Attachment 1

Commonwealth of Virginia

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

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Andrew R. Wheeler
Secretary of Natural and Historic Resources

Michael S. Rolband, PE, PWD, PWS Emeritus
Director
(804) 698-4000

March 11, 2022

Via email:andrew.wheeler@governor.virginia.gov

The Honorable Andrew S. Wheeler
Secretary of Natural and Historic Resources
1111 East Broad Street
Fourth Floor
Richmond, VA 23219

Re: EO-9

Dear Secretary Wheeler:

Governor Youngkin's Executive Order (EO) 9, signed on January 15, directs the Department of Environmental Quality to coordinate with you in completing the following by February 14:

1. Provide [the Governor] a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data;

2. Develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal Part VII of 9VAC5-140;

3. Take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the Code of Virginia; and

4. Notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

Pursuant to EO-9, therefore, enclosed for your review are the following:

- A draft report re-evaluating the costs and benefits of participation in RGGI in view of all available data (Item 1);

- A draft emergency regulation (Item 2), along with a brief description of the process for promulgating an emergency regulation under Va. Code §2.2-4011, including a draft letter to the Attorney General asking for his approval as required by that statute (Item 3);

- A brief description of the process and timetable for turning an emergency regulation into a permanent regulation under the Administrative Process Act, including a draft Notice of Intended Regulatory Action (NOIRA) to commence that process (Item 3); and

- A draft letter for your signature notifying RGGI, Inc., of the Governor's intent of withdrawing the Commonwealth from the RGGI program (Item 4).

Please let me know if you have any questions. My staff and I would be glad to brief this report with you at your convenience.

Sincerely,

Michael S. Rolband

VIRGINIA CARBON TRADING RULE AND REGIONAL GREENHOUSE GAS INITIATIVE (RGGI) PARTICIPATION

COSTS AND BENEFITS

A Report to the Honorable Glenn Youngkin, Governor Commonwealth of Virginia

Department of Environmental Quality
in coordination with
The Secretary of Natural and Historic Resources

MARCH 11, 2022

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EXECUTIVE SUMMARY

On July 10, 2020, Virginia formally adopted the CO_2 Budget Trading Program (Part VII of 9VAC5-140) for the power sector to implement a carbon emissions trading and reduction program as authorized by the Clean Energy and Community Flood Preparedness Act (Article 4 of Chapter 1219 of the 2020 Acts of Assembly). The rule allowed for full participation in the Regional Greenhouse Gas Initiative (RGGI) to reduce carbon dioxide (CO_2) emissions and make emissions allowances available for sale through an auction program that power producers use for compliance purposes. Proceeds from allowance sales are returned to Virginia to fund climate mitigation and resilience programs. Adoption of the rule was the result of a 3-year process that produced a program based on a consignment auction approach, and then transitioned into a full auction program as authorized by the General Assembly in 2020. Virginia began full participation in RGGI on January 1, 2021, and participated in five quarterly auctions to date.

On January 15, 2022, Governor Youngkin issued Executive Order 9 (2022) (EO-9) to re-evaluate Virginia's participation in RGGI and immediately begin the regulatory process to end its participation. The re-evaluation is based on new information that points to higher costs for residential and industrial ratepayers due to participation in RGGI, and that the benefits of RGGI participation have not been realized. Most of this cost increase information come from the State's largest regulated utility, Dominion Energy, in rate increase filings before the State Corporation Commission to recover the costs of compliance with the carbon-trading rule that includes the cost of purchasing emissions allowances to cover their CO_2 emissions.

This report serves as the required program re-evaluation in light of all available data regarding the costs and benefits of the carbon-trading rule and participation in RGGI. However, the availability of new information is limited since Virginia has just completed its first year of participation. The focus of the evaluation will be on the program areas of ratepayer impacts, allowance prices, and emissions trends. It will also look at the various analyses performed on RGGI and related clean power programs such as the Virginia Clean Economy Act (VCEA). The report also refers to the recently submitted annual report to the Governor and General Assembly on the Virginia Clean Energy and Community Flood Preparedness Act.

Our review of the data in the report provides the following high level conclusions regarding RGGI:

- Because of the captive nature of their ratepayers, the ability for power-generators to fully pass on costs to consumers, and the fact that the Code of Virginia dedicates RGGI proceeds to grants programs, participation in RGGI is in effect a direct carbon tax on all households and businesses;
- RGGI fails to achieve its goal as a carbon "cap-and-trade" system because it lacks any incentive for power-generators to actually reduce carbon-intensive gas emissions;
- Carbon emissions rates have been reduced in Virginia by over 50% in the past 10 years, prior to the Commonwealth's participation in RGGI.

Summary of Findings

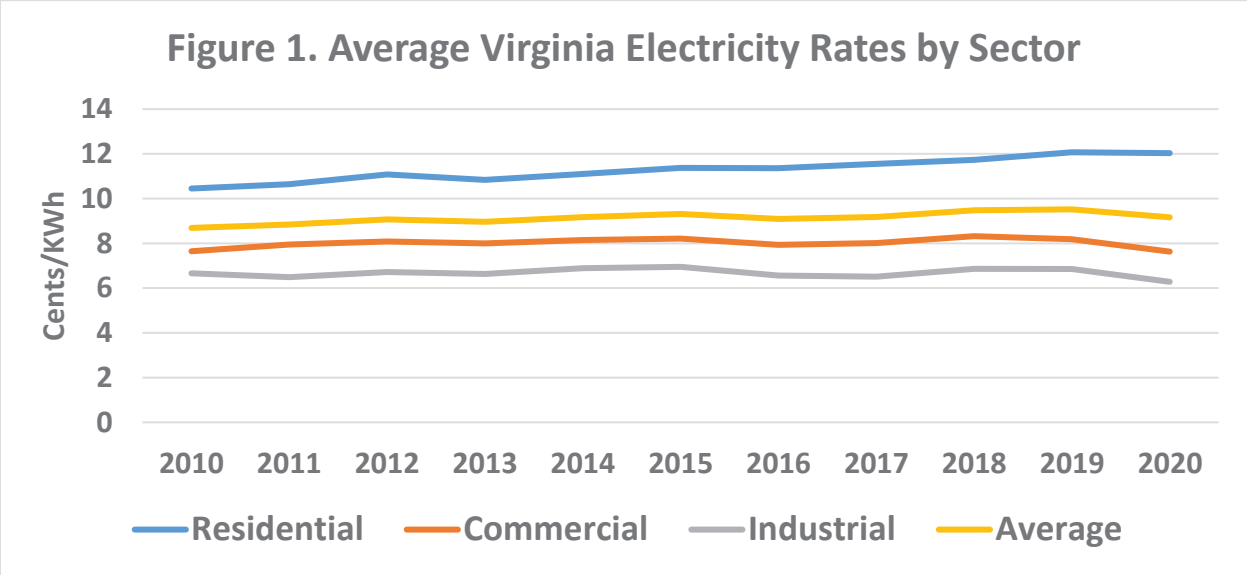
- Participation in RGGI in effect operates as a direct tax on households and businesses because all fees paid to the RGGI Board are passed through to utility-captive ratepayers.

- In addition, consumers are unable to avoid the pass through of these costs because they do not have the opportunity to switch electric providers – Dominion and other providers are monopolies in most regions of Virginia.
- The imposition of the RGGI "carbon tax" fails to offer any incentive to change behavior. Current law allows power generators, such Dominion Energy, to pass on all their costs, essentially bearing no cost for the carbon credits.
- Other states return the RGGI proceeds to consumers through rebates, while Virginia has opted to use the proceeds for separate and unrelated grant programs resulting in an effective tax increase on all ratepayers
- The original RGGI approach, prior to enactment, was designed to return the proceeds to the ratepayers in order to offset the costs of the program to the consumer, but this was not how Virginia implemented the program
- The costs of compliance with the trading rule and participation in RGGI have materialized in higher electricity rates as identified in the filings before the State Corporation Commission by Dominion Energy.
- Emission allowance prices have increased over time and substantially in the last year and are expected to continue increasing which will increase the tax on ratepayers.
- Lastly, without and prior to RGGI, electricity generation has increased while CO_2 per MWh has almost been cut in half in Virginia over the last ten years.
- RGGI is a bad construct that taxes consumers without providing incentives for change to the electricity producers.

SECTION 1 – ELECTRICITY RATE IMPACTS

One of the main concerns with participation in RGGI identified in EO-9 is the environmental compliance cost of RGGI on Virginia ratepayers. EO-9 states that the RGGI environmental compliance cost will increase "a typical" residential customer bill by $2.39 per month, and a typical industrial customer bill by $1,554 per month. EO-9 also states that Dominion Energy projects that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.

For background purposes, the historical trends of electricity rates from 2010 to 2020 are presented in Figure 1 below. These data show a gradual increase in all sector rates until 2020 where rates decline. Residential rates are the highest, followed by commercial with the industrial sector having the lowest average rates.



Source: Energy Information Administration

The first three-year control period for Virginia "CO_2 Budget Sources" began on January 1, 2021 and extends through December 31, 2023. Under each RGGI participating state's CO_2 Budget Trading Program, each "CO_2 budget source" is required to provide one CO_2 allowance for each ton of CO_2 emitted during the preceding three-year control period. Virginia utility law (Code of Virginia 56-585.1 A 4) allows Dominion and Appalachian Power ("CO_2 Budget Sources" under the CO_2 Budget Trading Program) to recover environmental compliance costs associated with participating in RGGI through new rate adjustment clauses.

On November 9, 2020, Dominion Energy filed a petition with the Virginia State Corporation Commission (SCC) to establish a new RGGI rate adjustment clause ("Rider RGGI") to recover $168,260,000 in "projected" RGGI compliance costs for the rate year of August 1, 2021 to July 31, 2022 (i.e., Case No. PUR-2020-00169), including:

- $129,960,000 for the purchase of 19 million allowances at $6.84 per allowance), and
- $38,330,000 of financing costs and a 9.2% rate of return associated with the purchase of 19 million allowances.

On August 4, 2021, the Commission issued an Order approving the Rider RGGI for initial year cost recovery starting on September 1, 2021 of $167.76 million (projected quantity and prices of allowances), 9.2% rate of return on projected allowance purchases, and finance costs associated with projected allowance purchases). As such, "the charge for service under Virginia Electric and Power Company's Filed Rate Schedules, as well as applicable energy charges specified in any special rates, contracts or incentives approved by the State Corporation Commission pursuant to Virginia Code § 56-235.2 shall be increased by 0.2393 cents per kilowatt-hour." The approved Rider RGGI explains the increase in a monthly residential customer electric bill and a monthly industrial customer electric bill of $2.39 and $1,554. The Order approving the Rider RGGI states, "RGGI is expected to cost Dominion's Virginia jurisdictional ratepayers approximately $3 billion [excluding finance costs] through 2045." The Order also states that any projected environmental compliance costs such as projected quantity and/or price of allowances and associated ROE and finance costs are to be trued-up in future Rider RGGI proceedings.

On August 24, 2021, a Petition for Reconsideration or Clarification ("Petition") was filed with the Commission. On November 17, 2021, the Commission issued its Order on Reconsideration, and elected not to modify the August 6, 2021 Order approving the Rider RGGI, with the exception of revised effective dates of the Rider RGGI:

- The first Rider RGGI tariff sheet is effective for usage on and after September 1, 2021 and reflects a rate of zero; and
- The next Rider RGGI tariff sheet is effective for usage on and after January 1, 2022, and reflects the 0.2393 cents per kilowatt-hour rate approved in the Rider RGGI Approval Order.

In December 2021, Dominion Energy filed a petition with the Commission for a revision of rate adjustment clause, "Rider RGGI" pursuant to § 56-585.1 A 5 e of the Code of Virginia (i.e., Case No. PUR-2021-0028). Dominion Energy withdrew the petition on January 10, 2022. The total environmental compliance cost recovery (i.e., revenue requirement) requested in the withdrawn Rider RGGI Petition for the Rate Year beginning September 1, 2022, was $323,411,000. It assumed an average price of $10.53 per allowance for the period of October 2021 through December 2023, a 9.35% ROE of allowances purchases, and finance costs associated with the allowance purchases. The withdrawn proposed petition for a revised rate adjustment clause would increase the approved Rider RGGI by 0.198 cents per kilowatt-hour, increasing the total Ride RGGI to 0.437 cents per kilowatt-hour.

Prices and quantities of allowances affect compliance costs, therefore, impact rate ratepayers. Data available on RGGI compliance costs are projected costs, because the actual quantity of allowance purchases and actual prices were not known at the time the new Rider RGGI was approved by the Commission.

Also, the second RGGI Program Review was completed in December 2017, resulting in the 2017 Model Rule, which was the foundation for the final rule subsequently adopted by Virginia as Part VII of 9VAC5-140 in accordance with the Clean Energy and Community Flood Preparedness Act. Resulting program modifications included changes to the Cost Containment Reserve (CCR) size and trigger price. The proposed CCR size from 2021 onwards will be 10% of the regional cap. The CCR trigger price will be $13.00 in 2021, and rise at 7% per year, ensuring that the CCR will only trigger if emission reduction costs are higher than projected.

In response to electricity rate concerns resulting from program compliance, four participating RGGI states, including Delaware, Maryland, Maine, and New Hampshire use a percentage of their allowance proceeds for direct bill assistance to mitigate the costs impact on ratepayers. In addition, North Carolina is seriously considering joining the RGGI program using the consignment approach modeled on the previous Virginia rule.

On February 2, 2021, the RGGI states, which include Virginia, released a statement announcing the plan for the Third Program Review to consider further updates to their programs, and in Summer 2021 the states released a preliminary timeline for conducting the Third Program Review, which will include a REMI macroeconomic analysis and bill impact analysis which may provide new information of future program costs and benefits.

The main conclusions of this section are as follows:

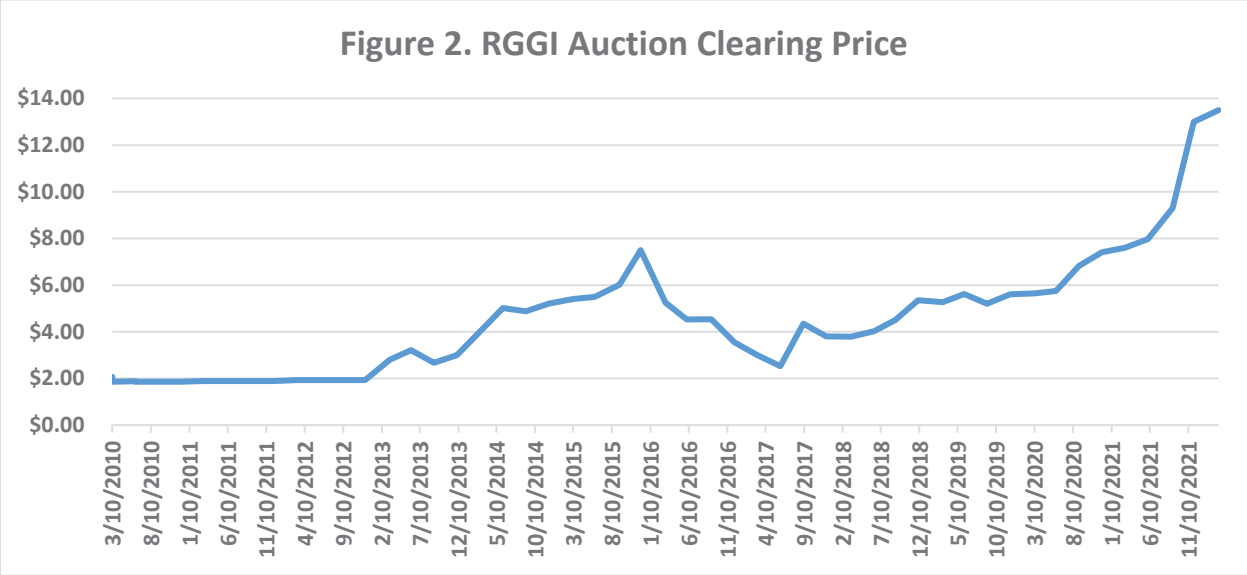
- The compliance costs of RGGI program participation have submitted by Dominion Energy and approved by the SCC, and have begun to impact electricity rates.
- These costs are and will continue to be directly related to the cost of allowances, along with other charges allowed under current law and regulations.
- Allowance prices have varied significantly in the past, and future prices will continue to vary.
- The social cost of carbon as required by VCEA has not been fully incorporated in the SCC process to date, but will be going forward, and may change future cost/benefit analyses.
- Four other RGGI participating states (and prospectively a fifth) provide bill assistance to customers using some of their auction proceeds.

SECTION 2 – ALLOWANCE PRICES AND AUCTION REVENUE

A central feature of any cap and trade program to reduce climate or criteria pollutant emissions is the concept of an emissions "allowance." An allowance usually represents the emission of one ton of pollution. These allowances are either sold or given to regulated entities for compliance or other purposes. As such, the allowance has value that is determined by the market through supply and demand. Reductions are achieved by gradually lowering the amount of allowances available in the market over time. RGGI operates under the concept where the allowances are allocated to the participating states and then sold through auctions. The proceeds are then returned to the states to support climate related programs.

Concern was raised in EO-9 about the rising cost of RGGI allowances and the resulting impact on electricity rates as described in more detail in Section 1 of this report. Therefore a review of allowance prices has been performed. Figure 2 shows the values of the RGGI auction clearing prices from 2010-2021. As shown in the figure, clearing prices have been volatile over time. Until 2014, prices remained below $4.00. From 2014 to 2017, the price rose to a high of $7.50 before falling to a low of $2.53. Since 2017, prices have risen steadily until experiencing a large jump in Auction 54, where the clearing price rose to the cost containment reserve (CCR) trigger level of $13.00. The cost containment reserve is a safeguard function of the RGGI program that sets a ceiling for allowance prices. Auction 54 is only the second time in the history of the program where the CCR has been triggered. The allowance price again increased slightly in Auction 55 to $13.50, an all-time high for the program, but did not trigger the updated CCR level

of $13.91 for 2022.



Source: Regional Greenhouse Gas Initiative Website

On the flip side of allowance prices is the proceeds generated by their sale that will go to support climate related mitigation and resilience programs. Thus far, Virginia has raised $301 million from the sale of allowances.

RGGI, Inc., administers quarterly auctions on behalf of the RGGI states where it offers allowances for sale to compliance entities and other groups. Virginia first participated in Auction 51, which was held on March 3, 2021, and the Commonwealth has participated in four additional auctions for a total of five. A summary of auction results is available in Table 1, and a distribution of funds raised from auctions is shown in Table 2.

It should be noted that RGGI, Inc., receives a small portion (0.3%) of Virginia's quarterly auction proceeds to fund its annual operating budget. Virginia's total payment to RGGI, Inc. for 2021 was $592,920.08. The payment due to RGGI Inc. for 2022 is $638,237.81.

Table 1: 2021 Auction Results Summary

	Allowances Sold	Allowance Price	Allowance Proceeds
Auction #51	5,735,509	$7.60	$43,589,868.40
Auction #52	5,698,446	$7.97	$45,416,614.62
Auction #53	5,698,445	$9.30	$52,995,538.50
Auction #54	6,587,274	$13.00	$85,634,562.00
Auction #55	5,497,712	$13.50	$74,219,112.00
Total	29,217,386		$301,855,695.52

The Clean Energy and Community Flood Preparedness Act provides that 45% and 50% of the proceeds generated from the auctions be used to fund the Virginia Community Flood

Preparedness Fund (CFPF) and the Housing Innovations in Energy Efficiency (HIEE) program, respectively. Administered by the Department of Housing and Community Development (DHCD), the CFPF helps localities across the Commonwealth reduce the impacts of flooding by implementing flood prevention and protection projects. Administered by the Department of Conservation and Recreation (DCR), the HIEE program makes energy efficiency upgrades to new and existing residential buildings to reduce energy bills for low-income Virginians. DEQ receives 3% of auction revenues to cover administrative expenses related to running the program and to carry out statewide climate change planning and mitigation activities. In partnership with the Virginia Department of Energy, DHCD receives 2% of the proceeds to administer and implement the HIEE program.

Table 2: Distribution of Funding

	RGGI	DHCD	DCR	DEQ	DHCD Admin
#51	$148,230.02	$21,720,819.19	$19,548,737.27	$1,303,249.15	$868,832.77
#52	$148,230.02	$22,634,192.30	$20,379,773.07	$1,358,051.54	$905,367.69
#53	$148,230.02	$26,423,654.24	$23,781,288.82	$1,585,419.25	$1,056,946.17
#54	$148,230.02	$42,743,165.99	$38,468,849.39	$2,564,589.96	$1,709,726.64
#55*	$159,559.45	$37,029,776.28	$33,326,798.65	$2,221,786.58	$1,481,191.05
Total	$75,2479.53	$150,551,608.00	$135,505,447.20	$9,033,096.48	$6,022,064.32

* Preliminary estimates

More information on the low-income energy efficiency and resiliency programs funded by auction proceeds can be found in the previously mentioned annual report on the Clean Energy and Community Flood Preparedness Act.

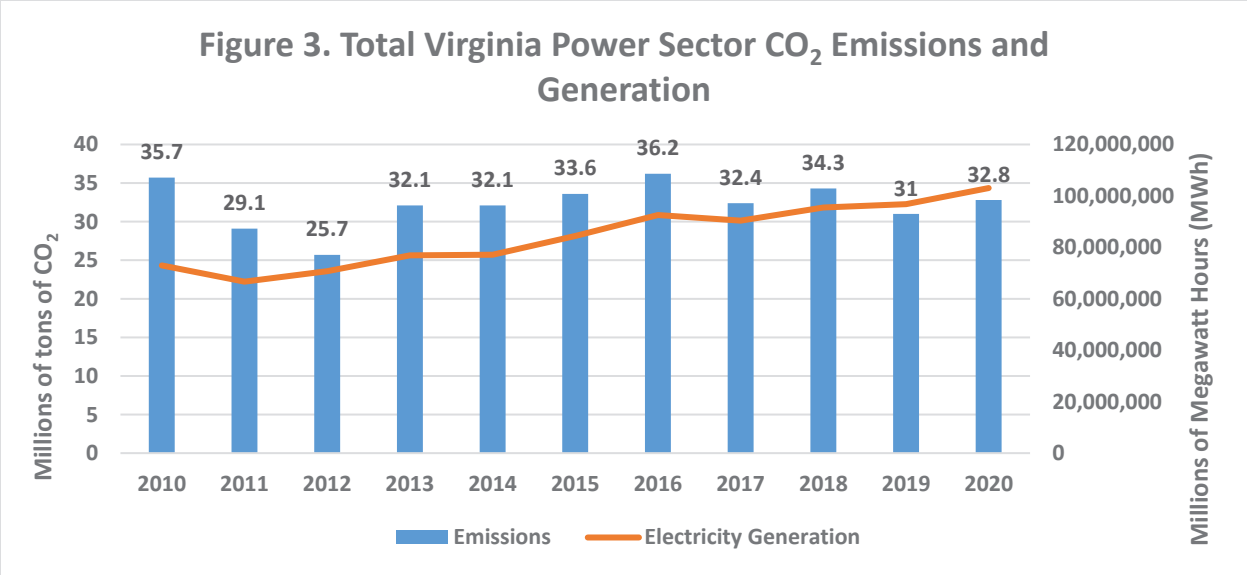
The main conclusions of this section are as follows:

- Allowance prices have varied widely over time.
- Allowance prices have increased sharply since 2020.
- Auction proceeds to Virginia for climate related programs have also increased based on these prices.
- Future allowance prices have been and will continue to be hard to predict.

SECTION 3 – POWER SECTOR GHG EMISSIONS TRENDS

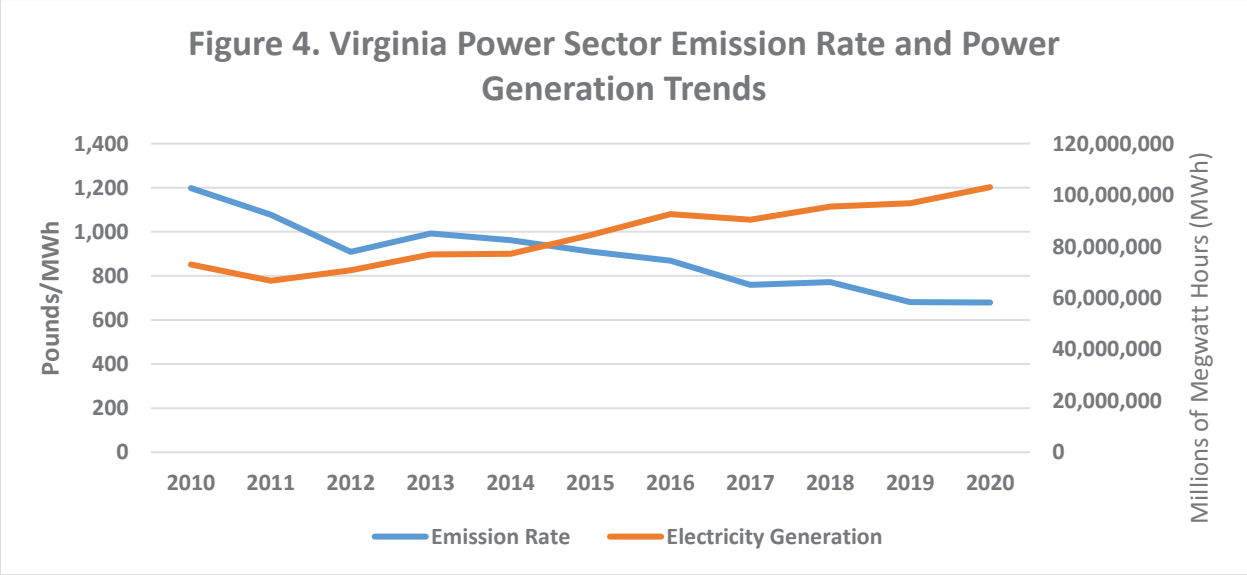
As mentioned earlier, emission reductions are the principle purpose and rationale of the carbon-trading rule and RGGI program. This is accomplished through setting emissions budgets and reducing them over time to achieve the desired reduction goal. It is too early to determine the impact of the program on emissions since 2021 is Virginia's first participation year.

However, to begin to assess this impact, the recent emission trends of the Virginia power sector must be evaluated. Emissions of CO_2 from the power sector are estimated and tracked by both the federal Environmental Protection Agency (EPA) and the DEQ. The recent trends in sector emissions are provided in Figure 3 below. It can be seen from the data that these emissions have fluctuated over the past 10 years with no discernable trend. During this period the average annual power sector emissions total in Virginia was 33.3 million tons.



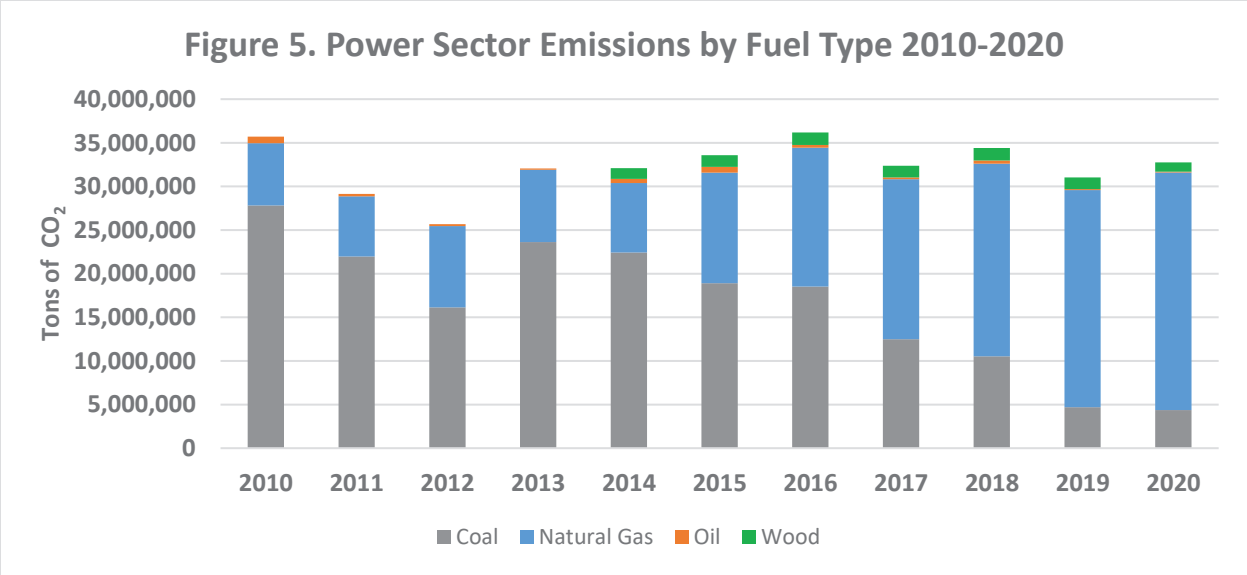
Source: EPA Air Markets Program Data and Energy Information Administration

While mass emissions have remained fairly constant, the overall state emission rate, which is the amount of CO_2 emissions produced by a set amount of electricity, has steadily and significantly been reduced. This trend is documented in Figure 4 where the statewide emission rate in 2010 was just under 1,200 lbs. per MWh that has then decreased to 679 lbs./MWh, which represents a 43% reduction in this average rate of CO_2 emissions per unit of electricity.



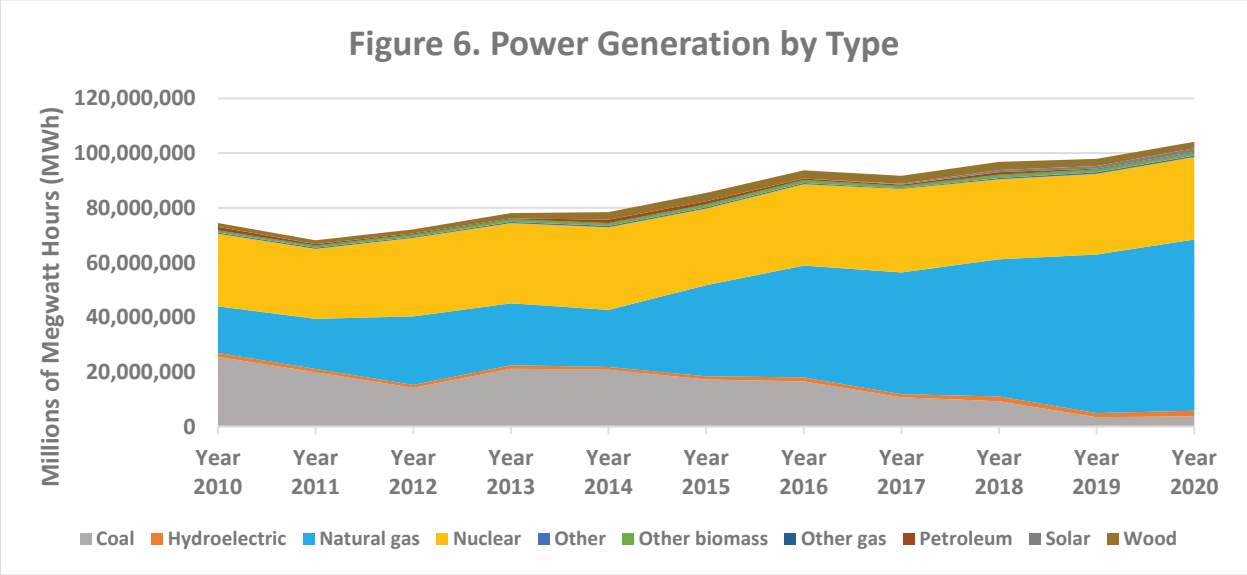
Source: Energy Information Administration

Given this mix of mass and emissions rate data and trends, a further data analysis is presented below in Figure 5 that shows that a major shift has occurred in the Virginia power sector where electricity generation from coal has been replaced by cleaner generation sources of natural gas and more recently renewable energy generation sources. Also during the same time, in-state electricity generation has increased by about 30%, which has led to the mass emissions levels remaining relatively constant.



Source: EPA Air Markets Program Data

A similar analysis of electricity generation by type is presented in Figure 6 that again shows the decrease in coal generation, increase in natural gas generation, and the introduction of renewable generation into the mix.



Source: Energy Information Administration

While these overall emissions and generation trends have occurred in the Virginia power sector, a number of source specific changes have occurred in Virginia's mix of power generation that will influence current and future emissions and generation trends. These changes, identified as new sources, closures and fuel conversions, are presented below in Table 3. From 2010 to 2020, six coal facilities closed, while five large combined cycle natural gas facilities have opened. Three coal facilities converted to biomass (wood) and one converted to gas.

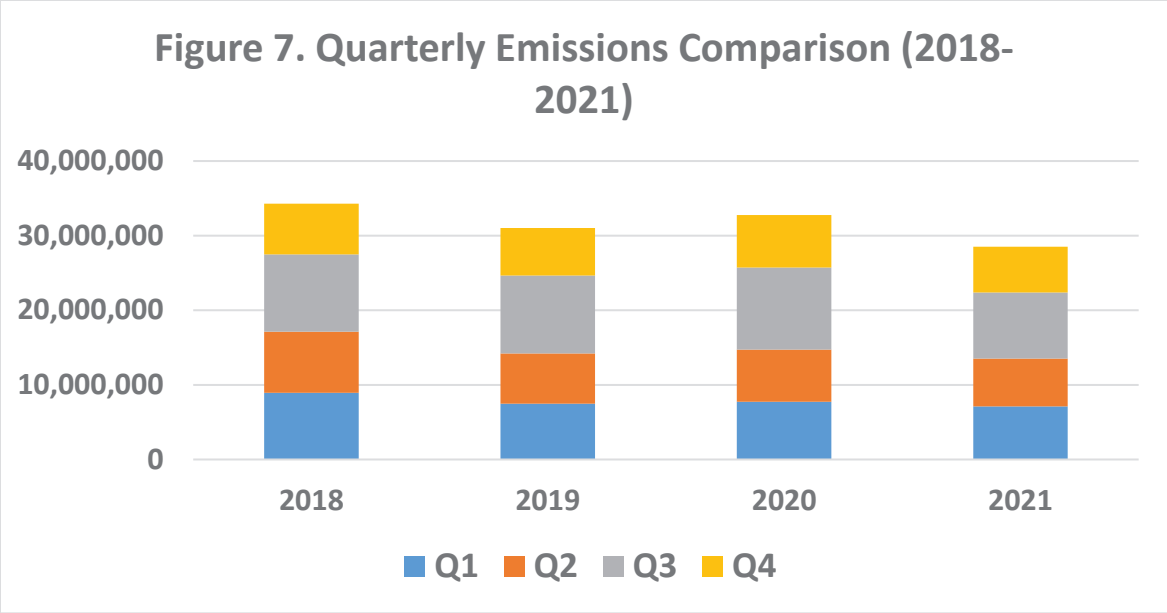
Table 3: Changes to Power Generation Sources in Virginia (2010-2020)

Plant Name	Change In Operation/Fuel	Year
Bear Garden Generating Station	Gas facility began operating	2011
Potomac River	Coal facility permanently closed	2012
Virginia City Hybrid Energy Center	Coal/biomass facility began operating	2012
Hopewell Power Station	Converted to biomass (wood) from coal	2013
NOVEC Halifax County Biomass Plant	Biomass facility began operating	2013
Southampton Power Station	Converted to biomass (wood) from coal	2013
Altavista Power Station	Converted to biomass (wood) from coal	2014
Bremo Power Station	Converted to gas from coal	2014
Chesapeake Energy Center	Coal facility permanently closed	2014
Warren County Power Station	Gas facility began operating	2014
Clinch River	Coal unit 3 retired, units 1 and 2 converted to gas	2015
Glen Lyn	Coal facility permanently closed	2015
Portsmouth Genco LLC	Coal facility permanently closed	2015
Brunswick County Power Station	Gas facility began operating	2016
Panda Stonewall Power Project	Gas facility began operating	2017
Bellemeade Power Station	Gas facility permanently closed	2018
Bremo Power Station	Gas facility permanently closed	2018
Chesterfield Power Station	Coal units 3 and 4 permanently closed	2018
Greensville County Power Station	Gas facility began operating	2018
Mecklenburg Power Station	Coal facility permanently closed	2018
Possum Point Power Station	Gas units 3 and 4 retired	2018
City Point Energy Center	Coal facility permanently closed	2019
Yorktown Power Station	Coal units 1 and 2 retired	2019
Possum Point Power Station	Oil unit 5 retired	2020

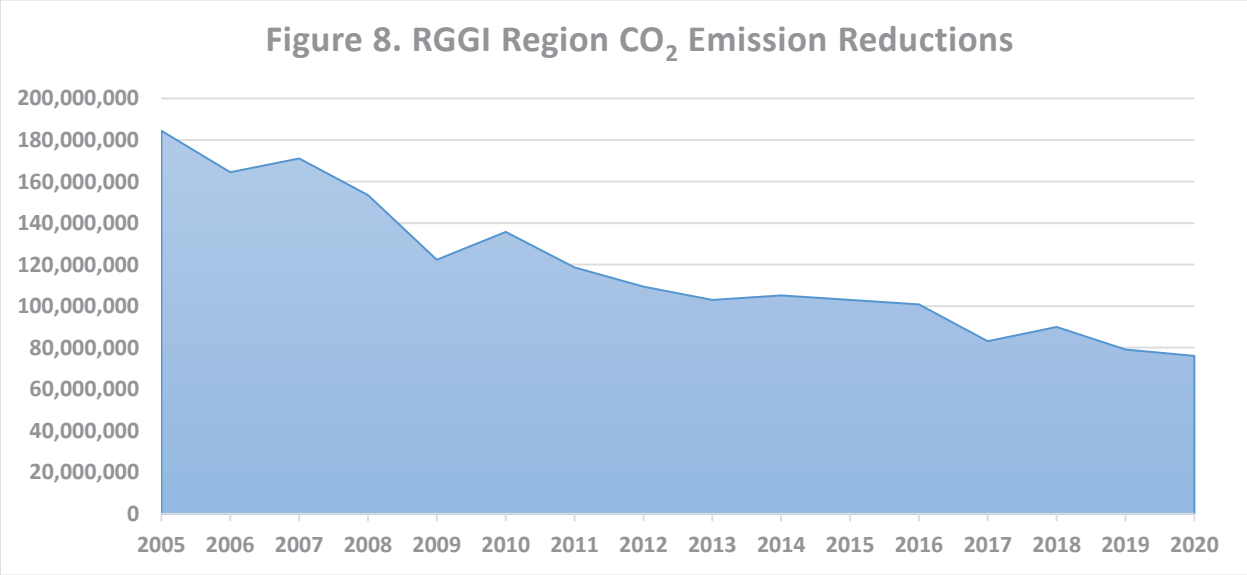
Source: PJM Generation Deactivations, EPA Air Markets Program Data tool

The carbon-trading rule and the RGGI program are designed to reduce regional CO_2 emissions over time by setting descending annual emission budgets to meet established reduction goals. The Virginia trading rule has established a starting emissions budget for 2021 of 27.6 million tons, which is then reduced annually at a consistent rate to 19.6 million tons in 2030. This is consistent with the RGGI goal of a 30% reduction between 2020 and 2030. However, since this is a regional trading program, the actual emissions reductions during this period may vary by state.

An analysis of control year 2021 emissions to date has been performed to see if any initial impact of the RGGI program can be seen in the Virginia power sector. To do so, the quarterly emissions data for 2021 have been compared the same data for past years. The results of this analysis are provided below in Figure 7. While there has been a decrease in emissions for 2021 as compared to prior years, this cannot be directly or solely attributed to RGGI participation.



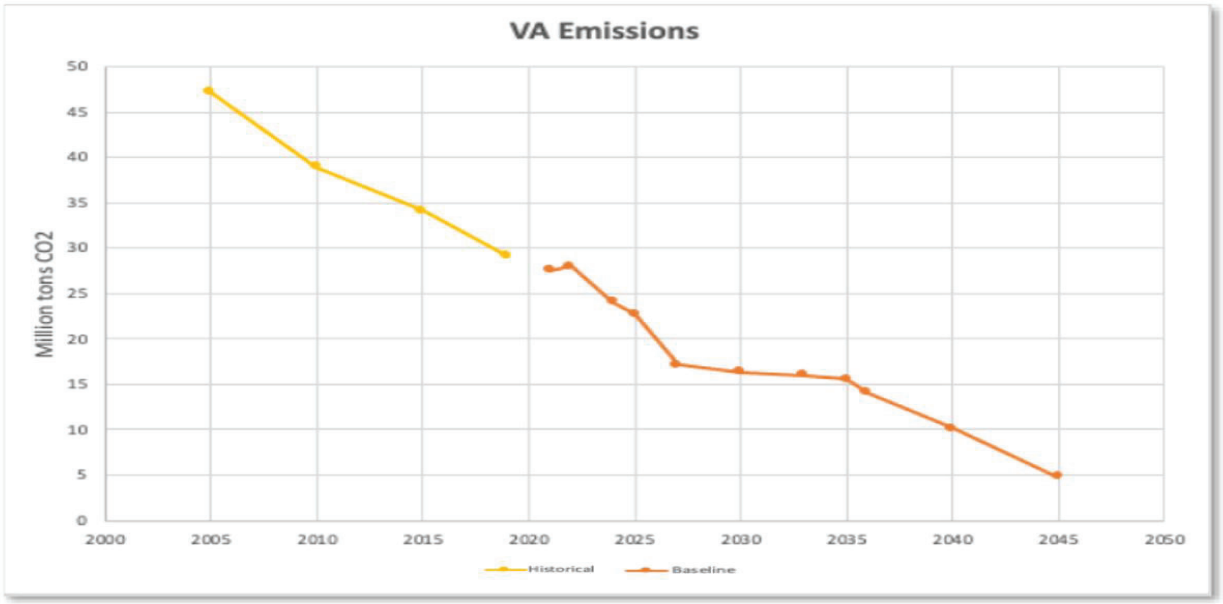
While the emissions data and impact of RGGI participation by Virginia is limited and inconclusive, the RGGI region has a long track record of emission reductions since the beginning of the program. This is shown in Figure 8 below where CO_2 emissions have decreased in the RGGI participating states by 59% from 2005 to 2020. Note that Virginia is not included in these data.



To assess the future of the power sector and predicted emissions reductions we must turn to modeling efforts that have been completed. A recently completed study and report completed by the Virginia Department of Energy, in consultation with the DEQ on the Virginia Clean Economy Act (VCEA) – Achieving Clean Electricity Generation at Least Cost to the Ratepayers by 2045. This study and report shows that the combination of participation in RGGI along with the specific mandates of the VCEA including the closure of most of the remaining coal and biomass electric generating facilities in Virginia, along with specific renewable energy

generation targets and standards, is expected to lead to a carbon free power sector in the 2045-2050 timeframe. This supports the requirements of both the VCEA and statutory goal of net-zero carbon emissions economy-wide by 2045. The CO_2 emissions reduction predictions of the study are provided in Figure 9.

Figure 9. CO_2 Emissions Reduction Predictions, VCEA Study



The main conclusions of this section are as follows:

- Mass emissions levels of CO_2 from the Virginia power sector have remained fairly constant over the last 10 years despite a 30% increase in power production.
- Average emission rates have substantially decreased during the same time and in-state electricity generation has increased.
- There is insufficient data to determine the impact of the trading rule and RGGI in reducing CO_2 emissions, since 2021 has been the first year of Virginia's participation in the program.
- The DOE study of the Virginia power sector indicates that an emission reduction program or combination of programs will be required to meet the Commonwealth's climate goals of the VCEA and the 2045 net-zero carbon emissions goal. In the absence of any such program, emissions may not reduce sufficiently to achieve these goals.

SECTION 4 – OTHER INFORMATION

Program Impact Analyses

As part of the regulatory process for the carbon-trading rule, a number of power sector and economic analyses were performed to determine the impact of the rule on generation, emissions, power prices, and allowance prices.

Prior to enactment of the Clean Energy and Community Flood Preparedness Act (CECFPA) in 2020 and subsequent carbon trading rule based on full auction participation, DEQ developed and

the SAPCB approved a trading rule that operated under a consignment auction approach. Under the consignment auction rule, Virginia's RGGI allowance budget was to be distributed directly to regulated sources on a pro rata basis according to a formula based on a source's historical CO_2 emissions. The regulated sources would then have been required to consign those allowances to the RGGI auction, with proceeds from the sale of the allowances at auction paid back to the regulated sources. The intention was that proceeds from consigned allowances would then flow to the ratepayers pursuant to a SCC process, thereby mitigating the cost of the RGGI program to ratepayers to the maximum extent. Two early analyses of the consignment auction approach indicated that electricity prices in Virginia would increase only nominally while consumer bills would actually go down. However, the CECFPA was enacted before the consignment rule could go into effect. The results of these analyses from 2017 and 2018 can be found at the following links.

November 2017

1. Policy Scenario 1
2. Policy Scenario 2
3. Reference Case 1
4. Reference Case 2
5. A bill analysis

November 2018

1. IPM reference case results
2. IPM policy case results
3. A bill analysis presentation
4. A co-benefits analysis

Also prior to Virginia becoming a full participant in RGGI, several economic impact analyses of the original CO_2 trading rule were completed by Virginia Department of Planning and Budget (DPB). This iteration of the rule implemented a consignment auction approach in lieu of a traditional auction approach in order to comply with as-then current state law. As required by § 2.2-4007.04 of the Administrative Process Act, DPB considered the economic impacts of the proposed, revised proposed, and final rule. These analyses considered a number of fiscal impact studies that were conducted as part of the regulatory development process. Note that the final regulation, which adopted the traditional auction approach, was exempt from the APA and therefore not subject to DPB review.

While these analyses informed the regulatory process at the time, they did not evaluate the rule in its current form. The IPM modeling also consistently underestimated allowance prices given the current price.

An independent comprehensive report on RGGI: Background, Impacts, and Selected Issues was published by the Congressional Research Service in 2019.

Finally, a more current study and report on the current and future power sector in Virginia has been performed to evaluate the combined impacts of the RGGI and VCEA programs as previously described in Section 3. However, this report does not assess the cost impact of the programs in detail.

Program Proceeds Investment

The RGGI program publishes annual reports on the investment of proceeds by its member states.

SECTION 5 - CONCLUSION

In conclusion, the results of this re-evaluation of the costs and benefits of the RGGI program on Virginia are as follows:

- RGGI operates as a direct tax on households and businesses because all fees paid to the RGGI Board are passed through to the ratepayers per Virginia Legislation. Since the utilities are allowed to increase their rates due to the costs associated with their required participation in the RGGI auction process, there is little correlation to emission reductions. By design the utilities are not penalized for failure to meet RGGI CO_2 emissions since they can pass on the costs to the ratepayers.
- Consumers are unable to avoid the pass through of these costs because they do not have the opportunity to switch electric providers – Dominion and other providers are monopolies in most regions of Virginia.
- Other states participating in the RGGI program designed their systems to provide rebates to their ratepayers, in Virginia the program operates as a hidden tax in which the legislature then disburses the funds through grant programs. Virginia consumers were originally told that the program would not increase their energy bills.
- The original RGGI auction approach was designed to return the proceeds to the ratepayers but this was not how Virginia implemented the program. The original analysis, conducted prior to the adoption of RGGI by the legislature, showed little impact on electricity prices to the consumer because of the anticipated return of the proceeds to the ratepayers.
- The costs of compliance with the trading rule and participation in RGGI are materializing in higher electricity rates for all ratepayers, as identified in the Dominion rate case filings. The first of these rate increase requests by Dominion Energy has been approved and went into effect on January 1. Future rate increases due to RGGI are expected and will be tied to the allowance prices which are difficult to predict.
- RGGI emissions allowance prices have increased over time and substantially in the last year. In fact, in Auction 54, the clearing price rose from $9.30 to the cost containment reserve trigger level of $13.00. The allowance price rose again slightly in Auction 55 to $13.50, an all-time high for the program. Future allowance price predictions will continue to be uncertain, but by design will continue to increase.
- In Virginia over the last 10 years energy generation has increased substantially while the CO_2 mass emissions has remained fairly constant. This is due to fuel switching and efficiencies, which is signified by the decreased emission rate. In 2010 the state produced 1,200 lbs/month of CO_2 per MWh compared to 679 lbs/CO_2 per MWh in 2020, prior to RGGI taking effect. Overall, CO_2 emissions in Virginia have fallen substantially since 2005, demonstrating that Virginia has been reducing their CO_2 emissions without regard to RGGI.
- RGGI is a bad construct that taxes consumers without providing incentives for change to the electricity producers. The program was not implemented in the way it was originally sold, and simply results in increased pricing to consumers out of the marketplace.

COMMONWEALTH OF VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY

PROCESS FOR ADDRESSING EO-9 EMERGENCY REGULATION AND REPEAL CO_2 EMISSIONS TRADING PROGRAM (PART VII OF 9VAC5-140)

Executive Order 9 (2022) (EO-9) **(Attachment A)** requires that DEQ in coordination with the Secretary develop an emergency regulation to repeal the CO_2 Emissions Trading Program regulation that enables Virginia to participate in the Regional Greenhouse Gas Initiative (RGGI), and begin the process for making the emergency regulation permanent. **Attachment B** shows the general process for doing so - in sum:

- in accordance with § 2.2-4011 A of the Administrative Process Act (APA) (**Attachment C**), the department consults with the Office of Attorney General to establish the nature of the emergency and requests the approval of the Attorney General in writing (**Attachment D**) to proceed with the emergency regulation;
- the State Air Pollution Control Board adopts the emergency regulation and submits it via Town Hall for executive review; and
- the emergency regulation becomes effective on approval by the Governor and submittal to the Registrar for publication.

In accordance with § 2.2-4011 C of the APA, an emergency regulation is effective for 18 months (24 months if an extension is requested). For an emergency regulation to become permanent, it must undergo the full regulatory adoption process during those 18 months. Thus, a Notice of Intended Regulatory Action (NOIRA) is usually issued concurrently with the emergency regulation. **Attachment E** describes this process and the schedule on which it must proceed. A draft proposed emergency regulation (**Attachment F**) and NOIRA for the permanent regulation (**Attachment G**) are provided.

EO-9 also requires DEQ in coordination with the Secretary to provide the Governor, "a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data, within 30 days," a draft of which will be provided separately. Finally, EO-9 directs the Secretary or DEQ to, ". . . notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action." A draft letter providing this notification for the Secretary's signature is provided at **Attachment H**.

Commonwealth of Virginia
Office of the Governor

Executive Order

NUMBER NINE (2022)

PROTECTING RATEPAYERS FROM THE RISING COST OF LIVING DUE TO THE REGIONAL GREENHOUSE GAS INITIATIVE

By virtue of the authority vested in me as Governor, I hereby issue this Executive Order to re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative and immediately begin regulatory processes to end it.

Importance of the Initiative

Reliable and affordable access to electricity is imperative to the health and safety of all Virginians. Our hospitals, schools, businesses, and homes all rely on this essential service. And the unpredictable and rising cost of electricity poses a significant and immediate threat to our Commonwealth and its citizens. In 2019, alone, over 100,000 Virginian households required Energy Assistance with a cost of $46 million to the Commonwealth.

Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) risks contributing to the increased cost of electricity for our citizens. Virginia's utilities have sold over $227 million in allowances in 2021 during the RGGI auctions, doubling the initial estimates. Those utilities are allowed to pass on the costs of purchasing allowances to their ratepayers. Under the initial bill "RGGI rider" created for Dominion Energy customers, typical residential customer bills were increased by $2.39 a month and the typical industrial customer bill by was raised by $1,554 per month. In a filling before the State Corporation Commission, Dominion Energy stated that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.

Simply stated, the benefits of RGGI have not materialized, while the costs have skyrocketed. Re-evaluation of the Initiative represents a meaningful step toward alleviating this financial burden on the Commonwealth's businesses and households. Regulations must be evaluated in view of the costs and benefits to all Virginians.

Directive

Accordingly, by virtue of the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural and Historic Resources, to take the following actions in accordance with the provisions and requirements of § 10.1-1300, et seq. and § 2.2-4000, et seq. of the *Code of Virginia*:

1. Provide me a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data, within 30 days.

2. During this same period, develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal 9VAC5-140.

3. During this same period, take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the *Code of Virginia*.

4. During this same period, notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

Effective Date

This Executive Order shall be effective upon its signing and shall remain in force and effect unless amended or rescinded by further executive order or directive.

Given under my hand and under the Seal of the Commonwealth of Virginia, this 15th day of January 2022.

Glenn Youngkin, Governor

Attest:

Kelly Thomasson, Secretary of the Commonwealth

Emergency regulations:

Information especially for state agencies

An emergency regulation is:

--Promulgated if (1) there is an "emergency situation" or (2) legislation requires a regulation to be promulgated within 280 days.

--Effective upon filing with the Registrar of Regulations.

--Initially effective for up to 18 months, and then may be extended for up to an additional 6 months if the Governor approves (for a total of 2 years).

--Usually replaced with a permanent regulation; therefore, a Notice of Intended Regulatory Action (NOIRA) to promulgate the permanent replacement regulation is normally filed at the same time as the emergency regulation.

Source: Section 2.2-4011 of the Code of Virginia

For more information, view the Town Hall User Manual at townhall.virginia.gov/UM/toc.cfm

Steps to promulgating:

Agency/board adopts emergency regulation and submits (Form TH-05 or TH06 and syncs RIS project) on the Town Hall for executive branch review.

↓

Executive branch review:
(In order of review)
Office of the Attorney General – no deadline;
Department of Planning & Budget – 14 day deadline;
Cabinet Secretary –14 day deadline;
Governor – no deadline.

↓

Once Governor approves, submit emergency regulation to the Virginia *Register of Regulations* via the Town Hall.
The emergency regulation is effective immediately upon filing.

↓

Ten days before publication in the *Register*, email notification is sent to registered public Town Hall users.

↓

The emergency regulation is published in the Register.
If NOIRA for permanent replacement regulation was also published, then 30-day public comment begins and Town Hall public comment forum opens.

Produced by the Virginia Department of Planning and Budget's Planning, Evaluation, and Regulation Division, 11/2018

ATTACHMENT C

Code of Virginia
Title 2.2. Administration of Government
Subtitle II. Administration of State Government
Part B. Transaction of Public Business
Chapter 40. Administrative Process Act
Article 2. Regulations

§ 2.2-4011. Emergency regulations; publication; exceptions

A. Regulations that an agency finds are necessitated by an emergency situation may be adopted by an agency upon consultation with the Attorney General, which approval shall be granted only after the agency has submitted a request stating in writing the nature of the emergency, and the necessity for such action shall be at the sole discretion of the Governor.

B. Agencies may also adopt emergency regulations in situations in which Virginia statutory law or the appropriation act or federal law or federal regulation requires that a regulation be effective in 280 days or less from its enactment and the regulation is not exempt under the provisions of subdivision A 4 of § 2.2-4006. In such cases, the agency shall state in writing the nature of the emergency and of the necessity for such action and may adopt the regulations. Pursuant to § 2.2-4012, such regulations shall become effective upon approval by the Governor and filing with the Registrar of Regulations.

C. All emergency regulations shall be limited to no more than 18 months in duration. During the 18-month period, an agency may issue additional emergency regulations as needed addressing the subject matter of the initial emergency regulation, but any such additional emergency regulations shall not be effective beyond the 18-month period from the effective date of the initial emergency regulation. If the agency wishes to continue regulating the subject matter governed by the emergency regulation beyond the 18-month limitation, a regulation to replace the emergency regulation shall be promulgated in accordance with this article. The Notice of Intended Regulatory Action to promulgate a replacement regulation shall be filed with the Registrar within 60 days of the effective date of the emergency regulation and published as soon as practicable, and the proposed replacement regulation shall be filed with the Registrar within 180 days after the effective date of the emergency regulation and published as soon as practicable.

D. In the event that an agency concludes that despite its best efforts a replacement regulation cannot be adopted before expiration of the 18-month period described in subsection C, it may seek the prior written approval of the Governor to extend the duration of the emergency regulation for a period of not more than six additional months. Any such request must be submitted to the Governor at least 30 days prior to the scheduled expiration of the emergency regulation and shall include a description of the agency's efforts to adopt a replacement regulation together with the reasons that a

replacement regulation cannot be adopted before the scheduled expiration of the emergency regulation. Upon approval of the Governor, provided such approval occurs prior to the scheduled expiration of the emergency regulation, the duration of the emergency regulation shall be extended for a period of no more than six months. Such approval shall be in the sole discretion of the Governor and shall not be subject to judicial review. Agencies shall notify the Registrar of Regulations of the new expiration date of the emergency regulation as soon as practicable.

E. Emergency regulations shall be published as soon as practicable in the Register.

F. The Regulations of the Marine Resources Commission shall be excluded from the provisions of this section.

ATTACHMENT D

January XX, 2022

The Honorable Jason S. Miyares
Attorney General of Virginia
202 North Ninth Street
Richmond, VA 23219

Dear Attorney General Miyares:

Pursuant to Va. Code §2.2-4011, the Department of Environmental Quality (DEQ) is asking your concurrence that an emergency situation exists with respect to Virginia's carbon trading program and participation in the Regional Greenhouse Gas Initiative (RGGI), and approval for DEQ to issue an emergency regulation to repeal the sections of 9VAC5-140 that establish and regulate the state's carbon trading program and participation in RGGI (VAC5-140-6010 through 6440). DEQ is making this request in accordance with Executive Order (EO) 9 issued by Governor Youngkin on January 15, 2021. (A copy of EO-9 is attached.)

Va. Code §2.2-4011 states that your approval of an emergency regulation, "shall be granted only after the agency has submitted a request stating in writing the nature of the emergency, and the necessity for such action shall be at the sole discretion of the Governor." The nature of this emergency is described by the Governor in EO-9 as follows:

> Reliable and affordable access to electricity is imperative to the health and safety of all Virginians. Our hospitals, schools, businesses, and homes all rely on this essential service. And the unpredictable and rising cost of electricity poses a significant and immediate threat to our Commonwealth and its citizens. In 2019, alone, over 100,000 Virginian households required Energy Assistance with a cost of $46 million to the Commonwealth.
>
> Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) risks contributing to the increased cost of electricity for our citizens. Virginia's utilities have sold over $227 million in allowances in 2021 during the RGGI auctions, doubling the initial estimates. Those utilities are allowed to pass on the costs of purchasing allowances to their ratepayers. Under the initial bill "RGGI rider" created for Dominion Energy customers, typical residential customer bills were increased by $2.39 a month and the typical industrial customer bill by was raised by $1,554 per month. In a filling before the State Corporation Commission, Dominion Energy stated that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.

Simply stated, the benefits of RGGI have not materialized, while the costs have skyrocketed. Re-evaluation of the Initiative represents a meaningful step toward alleviating this financial burden on the Commonwealth's businesses and households. Regulations must be evaluated in view of the costs and benefits to all Virginians.

Concurrent with making this request and in conformance with Va. Code §2.2-4011 and EO-9, DEQ is preparing a Notice of Intended Regulatory Action (NOIRA) to commence the process of bringing to the State Air Pollution Control Board for its consideration a proposed rule to make the repeal of Virginia's carbon trading program permanent.

Should you find that further consultation between your office and DEQ pursuant to Va. Code §2.2-4011 would be helpful in this matter, please do not hesitate to contact me. Thank you for your prompt attention to this request.

Sincerely,

Michael S. Rolband

ATTACHMENT E

The following table summarizes the emergency regulation/NOIRA process.

	DEQ/OAG consultation period via letter
	Board adopts emergency regulation (ER)
	DEQ submits adopted ER for executive branch review (OAG/DPB/SNR/Governor)
	Governor approves ER which is effective on filing; NOIRA filed same time
	Replacement Regulation (RR) Clock Starts
MONTH	DELIVERABLE
1	Submit NOIRA (filed automatically with ER)
2	30 day NOIRA comment period
3	prepare response to comments and board book
4	
5	board adopt proposed RR for public comment
6	proposed RR filed for executive branch review within 180 days after ER effective date
7	60 day proposed comment period starts
8	60 day proposed comment period ends
9	
10	
11	
12	
13	board adopt final RR
14	final RR filed for executive branch review within 180 days after end of proposed comment period
15	
16	
17	*request extension if needed*
18	original RR completion date
19	*6-month extension*
20	
21	
22	
23	
24	*RR final*

ATTACHMENT F

Project 7070 - Emergency/NOIRA

State Air Pollution Control Board

Repeal CO2 Budget Trading Program as required by Executive Order 9 (Revision A22)

~~Part VII~~

~~CO_2 Budget Trading Program~~

~~Article 1~~

~~CO_2 Budget Trading Program General Provisions~~

9VAC5-140-6010. ~~Purpose.~~ (Repealed.)

~~Article 1~~

~~CO_2 Budget Trading Program General Provisions~~

~~This part establishes the Virginia component of the CO_2 Budget Trading Program, which is designed to reduce anthropogenic emissions of CO_2, a greenhouse gas, from CO_2 budget sources in a manner that is protective of human health and the environment and is economically efficient.~~

9VAC5-140-6020. ~~Definitions.~~ (Repealed.)

~~A. As used in this part, all words or terms not defined here shall have the meanings given them in 9VAC5-10 (General Definitions), unless otherwise required by the context.~~

~~B. For the purpose of this part and any related use, the words or terms shall have the meanings given them in this section.~~

~~C. Terms defined.~~

~~"Account number" means the identification number given by the department or its agent to each COATS account.~~

~~"Acid Rain emission limitation" means, as defined in 40 CFR 72.2, a limitation on emissions of sulfur dioxide (SO_2) or nitrogen oxides (NO_x) under the Acid Rain Program under Title IV of the CAA.~~

~~"Acid Rain Program" means a multistate SO_2 and NO_x air pollution control and emission reduction program established by the administrator under Title IV of the CAA and 40 CFR Parts 72 through 78.~~

~~"Adjustment for banked allowances" means an adjustment applied to the Virginia CO_2 Budget Trading Program base budget for allocation years 2021 through 2025 to address allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states.~~

~~"Administrator" means the administrator of the U.S. Environmental Protection Agency or the administrator's authorized representative.~~

~~"Allocate" or "allocation" means the determination by the department of the number of CO_2 allowances recorded in the CO_2 allowance account of a CO_2 budget unit.~~

~~"Allocation year" means a calendar year for which the department allocates CO_2 allowances pursuant to Article 5 (9VAC5-140-6190 et seq.) of this part. The allocation year~~

of each CO_2 allowance is reflected in the unique identification number given to the allowance pursuant to 9VAC5-140-6250 C.

"Allowance auction" or "auction" means an auction in which the department or its agent offers CO_2 allowances for sale.

"Attribute" means a characteristic associated with electricity generated using a particular renewable fuel, such as its generation date, facility geographic location, unit vintage, emissions output, fuel, state program eligibility, or other characteristic that can be identified, accounted for, and tracked.

"Attribute credit" means a credit that represents the attributes related to one megawatt-hour of electricity generation.

"Automated Data Acquisition and Handling System" or "DAHS" means that component of the Continuous Emissions Monitoring System (CEMS), or other emissions monitoring system approved for use under Article 8 (9VAC5-140-6330 et seq.) of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by Article 8 (9VAC5-140-6330 et seq.) of this part.

"Billing meter" means a measurement device used to measure electric or thermal output for commercial billing under a contract. The facility selling the electric or thermal output shall have different owners from the owners of the party purchasing the electric or thermal output.

"Boiler" means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

"CO_2 allowance" means a limited authorization by the department or participating state under the CO_2 Budget Trading Program to emit up to one ton of CO_2, subject to all applicable limitations contained in this part.

"CO_2 allowance deduction" or "deduct CO_2 allowances" means the permanent withdrawal of CO_2 allowances by the department or its agent from a COATS compliance account to account for the number of tons of CO_2 emitted from a CO_2 budget source for a control period or an interim control period determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, or for the forfeit or retirement of CO_2 allowances as provided by this part.

"CO_2 Allowance Tracking System" or "COATS" means the system by which the department or its agent records allocations, deductions, and transfers of CO_2 allowances under the CO_2 Budget Trading Program. The tracking system may also be used to track CO_2 allowance prices and emissions from affected sources.

"CO_2 Allowance Tracking System account" means an account in COATS established by the department or its agent for purposes of recording the allocation, holding, transferring, or deducting of CO_2 allowances.

"CO_2 allowance transfer deadline" means midnight of March 1 occurring after the end of the relevant control period and each relevant interim control period, or if that March 1 is not a business day, midnight of the first business day thereafter and is the deadline by which CO_2 allowances shall be submitted for recordation in a CO_2 budget source's compliance account for the source to meet the CO_2 requirements of 9VAC5-140-6050 C for a control period and each interim control period immediately preceding such deadline.

"CO_2 allowances held" or "hold CO_2 allowances" means the CO_2 allowances recorded by the department or its agent, or submitted to the department or its agent for recordation, in

accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 7 (9VAC5-140-6300 et seq.) of this part, in a COATS account.

"CO_2 authorized account representative" means, for a CO_2 budget source and each CO_2 budget unit at the source, the natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Article 2 (9VAC5-140-6080 et seq.) of this part, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the natural person who is authorized, under Article 6 (9VAC5-140-6220 et seq.) of this part, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then for a CO_2 Budget Trading Program compliance account, this natural person shall be the same person as the designated representative as defined in the respective program.

"CO_2 authorized alternate account representative" means, for a CO_2 budget source and each CO_2 budget unit at the source, the alternate natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Article 2 (9VAC5-140-6080 et seq.) of this part, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the alternate natural person who is authorized, under Article 6 (9VAC5-140-6220 et seq.) of this part, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program then, for a CO_2 Budget Trading Program compliance account, this alternate natural person shall be the same person as the alternate designated representative as defined in the respective program.

"CO_2 budget emissions limitation" means, for a CO_2 budget source, the tonnage equivalent, in CO_2 emissions in a control period or an interim control period of the CO_2 allowances available for compliance deduction for the source for a control period or an interim control period.

"CO_2 budget permit" means the portion of the legally binding permit issued by the department pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) to a CO_2 budget source or CO_2 budget unit that specifies the CO_2 Budget Trading Program requirements applicable to the CO_2 budget source, to each CO_2 budget unit at the CO_2 budget source, and to the owners and operators and the CO_2 authorized account representative of the CO_2 budget source and each CO_2 budget unit.

"CO_2 budget source" means a source that includes one or more CO_2 budget units.

"CO_2 Budget Trading Program" means a multistate CO_2 air pollution control and emissions reduction program established according to this part and corresponding regulations in other states as a means of reducing emissions of CO_2 from CO_2 budget sources.

"CO_2 budget unit" means a unit that is subject to the CO_2 Budget Trading Program requirements under 9VAC5-140-6040.

"CO_2 cost containment reserve allowance" or "CO_2 CCR allowance" means an allowance that has been sold at an auction for the purpose of containing the cost of CO_2 allowances. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program base and adjusted budgets. CO_2 CCR allowances are subject to all applicable limitations contained in this part.

~~"CO_2 cost containment reserve trigger price" or "CCR trigger price" means the minimum price at which CO_2 CCR allowances are offered for sale by the department or its agent at an auction. The CCR trigger price in calendar year 2021 shall be $13. The CCR trigger price in calendar year 2022 shall be $13.91. Each calendar year thereafter, the CCR trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1A.~~

~~Table 140-1A~~
~~CO_2 CCR Trigger Price~~

~~2021~~	~~$13.00~~
~~2022~~	~~$13.91~~
~~2023~~	~~$14.88~~
~~2024~~	~~$15.92~~
~~2025~~	~~$17.03~~
~~2026~~	~~$18.22~~
~~2027~~	~~$19.50~~
~~2028~~	~~$20.87~~
~~2029~~	~~$22.33~~
~~2030~~	~~$23.89~~

~~"CO_2 emissions containment reserve allowance" or "CO_2 ECR allowance" means a CO_2 allowance that is withheld from sale at an auction by the department for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.~~

~~"CO_2 emissions containment reserve trigger price" or "ECR trigger price" means the price below which CO_2 allowances will be withheld from sale by the department or its agent at an auction. The ECR trigger price in calendar year 2021 shall be $6.00. Each calendar year thereafter, the ECR trigger price shall be 1.07 multiplied by the ECR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1B.~~

~~Table 140-1B~~
~~CO_2 ECR Trigger Price~~

~~2021~~	~~$ 6.00~~
~~2022~~	~~$ 6.42~~
~~2023~~	~~$ 6.87~~
~~2024~~	~~$ 7.35~~
~~2025~~	~~$ 7.86~~
~~2026~~	~~$8.41~~
~~2027~~	~~$ 9.00~~
~~2028~~	~~$ 9.63~~

2029	$10.30
2030	$11.02

"CO_2 offset allowance" means a CO_2 allowance that is awarded to the sponsor of a CO_2 emissions offset project by a participating state and is subject to the relevant compliance deduction limitations of the participating state's corresponding offset regulations as a means of reducing CO_2 from CO_2 budget sources.

"Combined cycle system" means a system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

"Combustion turbine" means an enclosed fossil or other fuel-fired device that is comprised of a compressor (if applicable), a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

"Commence commercial operation" means, with regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. For a unit that is a CO_2 budget unit under 9VAC5-140-6040 on the date the unit commences commercial operation, such date shall remain the unit's date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under 9VAC5-140-6040 on the date the unit commences commercial operation, the date the unit becomes a CO_2 budget unit under 9VAC5-140-6040 shall be the unit's date of commencement of commercial operation.

"Commence operation" means to begin any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber. For a unit that is a CO_2 budget unit under 9VAC5-140-6040 on the date of commencement of operation, such date shall remain the unit's date of commencement of operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under 9VAC5-140-6040 on the date of commencement of operation, the date the unit becomes a CO_2 budget unit under 9VAC5-140-6040 shall be the unit's date of commencement of operation.

"Compliance account" means a COATS account, established by the department or its agent for a CO_2 budget source under Article 6 (9VAC5-140-6220 et seq.) of this part, in which CO_2 allowances available for use by the source for a control period and each interim control period are held for the purpose of meeting the CO_2 requirements of 9VAC5-140-6050 C.

"Continuous Emissions Monitoring System" or "CEMS" means the equipment required under Article 8 (9VAC5-140-6330 et seq.) of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated DAHS), a permanent record of stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with 40 CFR Part 75 and Article 8 (9VAC5-140-6330 et seq.) of this part. The following systems are types of CEMS required under Article 8 (9VAC5-140-6330 et seq.) of this part:

a. A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour;

b. A NO_x emissions rate (or NO_x-diluent) monitoring system, consisting of a NO_x pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated

DAHS and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emissions rate, in pounds per million British thermal units (lb/MMBtu);

c. A moisture monitoring system, as defined in 40 CFR 75.11(b)(2) and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

d. A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated DAHS and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

e. An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated DAHS and providing a permanent, continuous record of O_2, in percent O_2.

"Control period" means a three-calendar-year time period. The fifth control period is from January 1, 2021, to December 31, 2023, inclusive, which is the first control period of Virginia's participation in the CO_2 Budget Trading Program. The first two calendar years of each control period are each defined as an interim control period, beginning on January 1, 2021.

"Cross State Air Pollution Rule (CSAPR) NO_X Annual Trading Program" means a multistate NO_X air pollution control and emission reduction program established in accordance with Subpart AAAAA of 40 CFR Part 97 and 40 CFR 52.38(a), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.38(a)(3) or (4) or that is established in a SIP revision approved by the administrator under 40 CFR 52.38(a)(5), as a means of mitigating interstate transport of fine particulates and NO_X.

"Cross State Air Pollution Rule (CSAPR) NO_X Ozone Season Trading Program" means a multistate NO_X air pollution control and emission reduction program established in accordance with Subpart BBBBB of 40 CFR Part 97 and 40 CFR 52.38(b), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.38(b)(3) or (4) or that is established in a SIP revision approved by the administrator under 40 CFR 52.38(b)(5), as a means of mitigating interstate transport of ozone and NO_X.

"Cross State Air Pollution Rule (CSAPR) SO_2 Group 1 Trading Program" means a multistate SO_2 air pollution control and emission reduction program established in accordance with Subpart CCCCC of 40 CFR Part 97 and 40 CFR 52.39(a), (b), (d) through (f), (j), and (k), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.39(d) or (e) or that is established in a SIP revision approved by the administrator under 40 CFR 52.39(f), as a means of mitigating interstate transport of fine particulates and SO_2.

"Cross State Air Pollution Rule (CSAPR) SO_2 Group 2 Trading Program" means a multistate SO_2 air pollution control and emission reduction program established in accordance with Subpart DDDDD of 40 CFR Part 97 and 40 CFR 52.39(a), (c), and (g) through (k), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.39(g) or (h) or that is established in a SIP revision approved by the administrator under 40 CFR 52.39(i), as a means of mitigating interstate transport of fine particulates and SO_2.

"Department" means the Virginia Department of Environmental Quality.

"Excess emissions" means any tonnage of CO_2 emitted by a CO_2 budget source during an interim control period or a control period that exceeds the CO_2 budget emissions limitation for the source.

"Excess interim emissions" means any tonnage of CO_2 emitted by a CO_2 budget source during an interim control period multiplied by 0.50 that exceeds the CO_2 budget emissions limitation for the source.

"Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

"Fossil fuel-fired" means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 5.0% of the annual heat input on a Btu basis during any year.

"General account" means a COATS account established under Article 6 (9VAC5-140-6220 et seq.) of this part that is not a compliance account.

"Gross generation" means the electrical output in MWe at the terminals of the generator.

"Interim control period" means a one-calendar-year time period during each of the first and second calendar years of each three-year control period. The first interim control period starts January 1, 2021, and ends December 31, 2021, inclusive. The second interim control period starts January 1, 2022, and ends December 31, 2022, inclusive. Each successive three-year control period will have two interim control periods, comprised of each of the first two calendar years of that control period.

"Life-of-the-unit contractual arrangement" means either:

a. A unit participation power sales agreement under which a customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity or associated energy from any specified unit pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period equal to or greater than 25 years or 70% of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period; or

b. Any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO_2 budget source or CO_2 budget unit and is entitled to receive all of the nameplate capacity and associated energy generated by such source or unit for the entire contractual period. Such agreements shall be subject to 9VAC5-140-6325. Such purchaser shall not be considered an "owner" as defined under this section.

"Maximum potential hourly heat input" means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use Appendix D of 40 CFR Part 75 to report heat input, this value shall be calculated, in accordance with 40 CFR Part 75, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value shall be reported, in accordance with 40 CFR Part 75, using the maximum potential flow rate and either the maximum CO_2 concentration in percent CO_2 or the minimum O_2 concentration in percent O_2.

"Minimum reserve price" means, in calendar year 2021, $2.38. Each calendar year thereafter, the minimum reserve price shall be 1.025 multiplied by the minimum reserve price from the previous calendar year, rounded to the nearest whole cent.

"Monitoring system" means any monitoring system that meets the requirements of Article 8 (9VAC5-140-6330 et seq.) of this part, including a CEMS, an excepted monitoring system, or an alternative monitoring system.

"Nameplate capacity" means the maximum electrical output in MWe that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the U.S. Department of Energy standards.

"Net-electric output" means the amount of gross generation in MWh the generators produce, including output from steam turbines, combustion turbines, and gas expanders, as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

"Non-CO_2 budget unit" means a unit that does not meet the applicability criteria of 9VAC5-140-6040.

"Operator" means any person who operates, controls, or supervises a CO_2 budget unit or a CO_2 budget source and shall include any holding company, utility system, or plant manager of such a unit or source.

"Owner" means any of the following persons:

a. Any holder of any portion of the legal or equitable title in a CO_2 budget unit;

b. Any holder of a leasehold interest in a CO_2 budget unit, other than a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the CO_2 budget unit;

c. Any purchaser of power from a CO_2 budget unit under a life-of-the-unit contractual arrangement in which the purchaser controls the dispatch of the unit; or

d. With respect to any general account, any person who has an ownership interest with respect to the CO_2 allowances held in the general account and who is subject to the binding agreement for the CO_2 authorized account representative to represent that person's ownership interest with respect to the CO_2 allowances.

"Participating state" means a state that has established a corresponding regulation as part of the CO_2 Budget Trading Program.

"Receive" or "receipt of" means, when referring to the department or its agent, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission) as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence by the department or its agent in the regular course of business.

"Recordation," "record," or "recorded" means, with regard to CO_2 allowances, the movement of CO_2 allowances by the department or its agent from one COATS account to another for purposes of allocation, transfer, or deduction.

"Reserve price" means the minimum acceptable price for each CO_2 allowance in a specific auction. The reserve price at an auction is either the minimum reserve price or the CCR trigger price, as specified in Article 9 (9VAC5-140-6410 et seq.) of this part.

"Serial number" means, when referring to CO_2 allowances, the unique identification number assigned to each CO_2 allowance by the department or its agent under 9VAC5-140-6250 C.

"Source" means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any air pollutant. A source, including a source with multiple units, shall be considered a single facility.

"Submit" or "serve" means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

a. In person;

b. By United States Postal Service; or

c. By other means of dispatch or transmission and delivery.

Compliance with any "submission," "service," or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

"Ton" or "tonnage" means any short ton, or 2,000 pounds. For the purpose of determining compliance with the CO_2 requirements of 9VAC5-140-6050 C, total tons for an interim control period or a control period shall be calculated as the sum of all recorded hourly emissions, or the tonnage equivalent of the recorded hourly emissions rates, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons. A short ton is equal to 0.9072 metric tons.

"Total useful energy" means the sum of gross electrical generation and useful net thermal energy.

"Undistributed CO_2 allowances" means CO_2 allowances originally allocated to a set aside account as pursuant to 9VAC5-140-6210 that were not distributed.

"Unit" means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

"Unit operating day" means a calendar day in which a unit combusts any fuel.

"Unsold CO_2 allowances" means CO_2 allowances that have been made available for sale in an auction conducted by the department or its agent, but not sold.

"Useful net thermal energy" means energy:

a. In the form of direct heat, steam, hot water, or other thermal form that is used in the production and beneficial measures for heating, cooling, humidity control, process use, or other thermal end use energy requirements, excluding thermal energy used in the power production process (e.g., house loads and parasitic loads); and

b. For which fuel or electricity would otherwise be consumed.

"Virginia CO_2 Budget Trading Program adjusted budget" means an adjusted budget determined in accordance with 9VAC5-140-6210 and is the annual amount of CO_2 tons available in Virginia for allocation in a given allocation year, in accordance with the CO_2 Budget Trading Program. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program adjusted budget.

"Virginia CO_2 Budget Trading Program base budget" means the budget specified in 9VAC5-140-6190. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program base budget.

9VAC5-140-6030. ~~Measurements, abbreviations, and acronyms.~~ (Repealed.)

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu - British thermal unit.

~~CAA - federal Clean Air Act.~~

~~CCR - cost containment reserve.~~

~~CEMS - Continuous Emissions Monitoring System.~~

~~COATS - CO_2 Allowance Tracking System.~~

~~CO_2 - carbon dioxide.~~

~~DAHS - Data Acquisition and Handling System.~~

~~H_2O - water.~~

~~lb - pound.~~

~~LME - low mass emissions.~~

~~MMBtu - million British thermal units.~~

~~MW - megawatt.~~

~~MWe - megawatt electrical.~~

~~MWh - megawatt hour.~~

~~NO_x - nitrogen oxides.~~

~~O_2 - oxygen.~~

~~ORIS - Office of Regulatory Information Systems.~~

~~QA/QC - quality assurance/quality control.~~

~~ppm - parts per million.~~

~~SO_2 - sulfur dioxide.~~

9VAC5-140-6040. ~~Applicability.~~ (Repealed.)

~~A. Any fossil fuel-fired unit that serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe shall be a CO_2 budget unit, and any source that includes one or more such units shall be a CO_2 budget source, subject to the requirements of this part.~~

~~B. Exempt from the requirements of this part is any fossil fuel CO_2 budget source located at or adjacent to and physically interconnected with a manufacturing facility that, prior to January 1, 2020, and in every subsequent calendar year, met either of the following requirements:~~

~~1. Supplies less than or equal to 10% of its annual net electrical generation to the electric grid; or~~

~~2. Supplies less than or equal to 15% of its annual total useful energy to any entity other than the manufacturing facility to which the CO_2 budget source is interconnected.~~

~~For the purpose of subdivision 1 of this subsection, annual net electrical generation shall be determined as follows:~~

~~(ES – EP) / EG x 100~~

~~Where:~~

~~ES = electricity sales to the grid from the CO_2 budget source~~

~~EP = electricity purchases from the grid by the CO_2 budget source and the manufacturing facility to which the CO_2 budget source is interconnected~~

~~EG = electricity generation~~

~~Such exempt CO_2 budget source shall have an operating permit containing the applicable restrictions under this subsection. An application for such operating permit shall be submitted to the department no later than January 1, 2022.~~

9VAC5-140-6050. ~~Standard requirements.~~ (Repealed.)

~~A. Permit requirements shall be as follows.~~

1. The CO_2 authorized account representative of each CO_2 budget source required to have an operating permit pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) and each CO_2 budget unit required to have an operating permit pursuant to 9VAC5-85 shall:

a. Submit to the department a complete CO_2 budget permit application under 9VAC5-140-6160 in accordance with the deadlines specified in 9VAC5-140-6150; and

b. Submit in a timely manner any supplemental information that the department determines is necessary in order to review the CO_2 budget permit application and issue or deny a CO_2 budget permit.

2. The owners and operators of each CO_2 budget source required to have an operating permit pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) and each CO_2 budget unit required to have an operating permit pursuant to 9VAC5-85 for the source shall have a CO_2 budget permit and operate the CO_2 budget source and the CO_2 budget unit at the source in compliance with such CO_2 budget permit.

B. Monitoring requirements shall be as follows.

1. The owners and operators and, to the extent applicable, the CO_2 authorized account representative of each CO_2 budget source and each CO_2 budget unit at the source shall comply with the monitoring requirements of Article 8 (9VAC5-140-6330 et seq.) of this part.

2. The emissions measurements recorded and reported in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part shall be used to determine compliance by the unit with the CO_2 requirements under subsection C of this section.

C. CO_2 requirements shall be as follows.

1. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions that have been generated as a result of combusting fossil fuel for an interim control period or control period from all CO_2 budget units at the source, less the CO_2 allowances deducted to meet the requirements of subdivision 2 of this subsection, with respect to the previous two interim control periods as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part.

2. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions that have been generated as a result of combusting fossil fuel for the interim control period from all CO_2 budget units at the source multiplied by 0.50, as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part.

3. Each ton of CO_2 emitted in excess of the CO_2 budget emissions limitation for a control period shall constitute a separate violation of this part and applicable state law.

4. Each ton of excess interim emissions shall constitute a separate violation of this part and applicable state law.

5. A CO_2 budget unit shall be subject to the requirements under subdivision 1 of this subsection starting on the later of January 1, 2021, or the date on which the unit commences operation.

6. CO_2 allowances shall be held in, deducted from, or transferred among COATS accounts in accordance with Article 5 (9VAC5-140-6190 et seq.), Article 6 (9VAC5-140-6220 et seq.), and Article 7 (9VAC5-140-6300 et seq.) of this part.

7. A CO_2 allowance shall not be deducted, to comply with the requirements under subdivision 1 or 2 of this subsection, for a control period that ends prior to the year for which the CO_2 allowance was allocated.

8. A CO_2 allowance under the CO_2 Budget Trading Program is a limited authorization by the department to emit one ton of CO_2 in accordance with the CO_2 Budget Trading Program. No provision of the CO_2 Budget Trading Program, the CO_2 budget permit application, or the CO_2 budget permit or any provision of law shall be construed to limit the authority of the department or a participating state to terminate or limit such authorization.

9. A CO_2 allowance under the CO_2 Budget Trading Program does not constitute a property right.

D. The owners and operators of a CO_2 budget source that has excess emissions in a control period shall:

1. Forfeit the CO_2 allowances required for deduction under 9VAC5-140-6260 D 1; and

2. Pay any fine, penalty, or assessment or comply with any other remedy imposed under 9VAC5-140-6260 D 2.

E. Recordkeeping and reporting requirements shall be as follows:

1. Unless otherwise provided, the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source shall keep on site at the source each of the following documents for a period of 10 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 10 years, in writing by the department.

a. The account certificate of representation for the CO_2 authorized account representative for the source and each CO_2 budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 9VAC5-140-6110, provided that the certificate and documents shall be retained on site at the source beyond such 10-year period until such documents are superseded because of the submission of a new account certificate of representation changing the CO_2 authorized account representative.

b. All emissions monitoring information, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part and 40 CFR 75.57.

c. Copies of all reports, compliance certifications, and other submissions and all records made or required under the CO_2 Budget Trading Program.

d. Copies of all documents used to complete a CO_2 budget permit application and any other submission under the CO_2 Budget Trading Program or to demonstrate compliance with the requirements of the CO_2 Budget Trading Program.

2. The CO_2 authorized account representative of a CO_2 budget source and each CO_2 budget unit at the source shall submit the reports and compliance certifications required under the CO_2 Budget Trading Program, including those under Article 4 (9VAC5-140-6170 et seq.) of this part.

F. Liability requirements shall be as follows.

1. No permit revision shall excuse any violation of the requirements of the CO_2 Budget Trading Program that occurs prior to the date that the revision takes effect.

2. Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget source, including a provision applicable to the CO_2 authorized account representative of a CO_2 budget source, shall also apply to the owners and operators of such source and of the CO_2 budget units at the source.

3. Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget unit, including a provision applicable to the CO_2 authorized account representative of a CO_2 budget unit, shall also apply to the owners and operators of such unit.

G. No provision of the CO_2 Budget Trading Program, a CO_2 budget permit application, or a CO_2 budget permit shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the CO_2 authorized account representative of the CO_2 budget source or CO_2 budget unit from compliance with any other provisions of applicable state and federal law or regulations.

9VAC5-140-6060. Computation of time. (Repealed.)

A. Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

B. Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

C. Unless otherwise stated, if the final day of any time period, under the CO_2 Budget Trading Program, falls on a weekend or a state or federal holiday, the time period shall be extended to the next business day.

9VAC5-140-6070. Severability. (Repealed.)

If any provision of this part, or its application to any particular person or circumstances, is held invalid, the remainder of this part, and the application thereof to other persons or circumstances, shall not be affected thereby.

Article 2

CO_2 Authorized Account Representative for CO_2 Budget Sources

9VAC5-140-6080. Authorization and responsibilities of the CO2 authorized account representative. (Repealed.)

Article 2

CO_2 Authorized Account Representative for CO_2 Budget Sources

A. Except as provided under 9VAC5-140-6090, each CO_2 budget source, including all CO_2 budget units at the source, shall have one and only one CO_2 authorized account representative, with regard to all matters under the CO_2 Budget Trading Program concerning the source or any CO_2 budget unit at the source.

B. The CO_2 authorized account representative of the CO_2 budget source shall be selected by an agreement binding on the owners and operators of the source and all CO_2 budget units at the source and must act in accordance with the account certificate of representation under 9VAC5-140-6110.

C. Upon receipt by the department or its agent of a complete account certificate of representation under 9VAC5-140-6110, the CO_2 authorized account representative of the source shall represent and, by his representations, actions, inactions, or submissions, legally bind each owner and operator of the CO_2 budget source represented and each CO_2 budget unit at the source in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative and such owners and operators. The owners

and operators shall be bound by any decision or order issued to the CO_2 authorized account representative by the department or a court regarding the source or unit.

D. No CO_2 budget permit shall be issued, and no COATS account shall be established for a CO_2 budget source, until the department or its agent has received a complete account certificate of representation under 9VAC5-140-6110 for a CO_2 authorized account representative of the source and the CO_2 budget units at the source.

E. Each submission under the CO_2 Budget Trading Program shall be submitted, signed, and certified by the CO_2 authorized account representative for each CO_2 budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CO_2 authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

F. The department or its agent will accept or act on a submission made on behalf of owners or operators of a CO_2 budget source or a CO_2 budget unit only if the submission has been made, signed, and certified in accordance with subsection E of this section.

9VAC5-140-6090. ~~CO2 authorized alternate account representative.~~ (Repealed.)

A. An account certificate of representation may designate one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative.

B. Upon receipt by the department or its agent of a complete account certificate of representation under 9VAC5-140-6110, any representation, action, inaction, or submission by the CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

C. Except in this section and 9VAC5-140-6080 A, 9VAC5-140-6100, 9VAC5-140-6110, and 9VAC5-140-6230, whenever the term "CO_2 authorized account representative" is used in this part, the term shall be construed to include the CO_2 authorized alternate account representative.

9VAC5-140-6100. ~~Changing the CO2 authorized account representatives and the CO2 authorized alternate account representative; changes in the owners and operators.~~ (Repealed.)

A. The CO_2 authorized account representative may be changed at any time upon receipt by the department or its agent of a superseding complete account certificate of representation under 9VAC5-140-6110. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative or CO_2 authorized alternate account representative prior to the time and date when the department or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

B. The CO_2 authorized alternate account representative may be changed at any time upon receipt by the department or its agent of a superseding complete account certificate of representation under 9VAC5-140-6110. Notwithstanding any such change, all representations,

~~actions, inactions, and submissions by the previous CO_2 authorized alternate account representative or CO_2 authorized alternate account representative prior to the time and date when the department or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized alternate account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.~~

~~C. Changes in the owners and operators shall be addressed as follows.~~

~~1. In the event a new owner or operator of a CO_2 budget source or a CO_2 budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative of the source or unit, and the decisions, orders, actions, and inactions of the department, as if the new owner or operator were included in such list.~~

~~2. Within 30 days following any change in the owners and operators of a CO_2 budget source or a CO_2 budget unit, including the addition of a new owner or operator, the CO_2 authorized account representative or CO_2 authorized alternate account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.~~

9VAC5-140-6110. ~~Account certificate of representation.~~ (Repealed.)

~~A. A complete account certificate of representation for a CO_2 authorized account representative or a CO_2 authorized alternate account representative shall include the following elements in a format prescribed by the department or its agent:~~

~~1. Identification of the CO_2 budget source and each CO_2 budget unit at the source for which the account certificate of representation is submitted;~~

~~2. The name, address, email address, telephone number, and facsimile transmission number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;~~

~~3. A list of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source;~~

~~4. The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: "I certify that I was selected as the CO_2 authorized account representative or CO_2 authorized alternate account representative, as applicable, by an agreement binding on the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Budget Trading Program on behalf of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the department or a court regarding the source or unit."; and~~

~~5. The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed.~~

~~B. Unless otherwise required by the department or its agent, documents of agreement referred to in the account certificate of representation shall not be submitted to the department or its agent. Neither the department nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.~~

9VAC5-140-6120. ~~Objections concerning the CO2 authorized account representative.~~ (Repealed.)

~~A. Once a complete account certificate of representation under 9VAC5-140-6110 has been submitted and received, the department and its agent will rely on the account certificate of representation unless and until the department or its agent receives a superseding complete account certificate of representation under 9VAC5-140-6110.~~

~~B. Except as provided in 9VAC5-140-6100 A or B, no objection or other communication submitted to the department or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or the finality of any decision or order by the department or its agent under the CO_2 Budget Trading Program.~~

~~C. Neither the department nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CO_2 authorized account representative, including private legal disputes concerning the proceeds of CO_2 allowance transfers.~~

9VAC5-140-6130. ~~Delegation by CO2 authorized account representative and CO2 authorized alternate account representative.~~ (Repealed.)

~~A. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent under this part.~~

~~B. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent under this part.~~

~~C. To delegate authority to make an electronic submission to the department or its agent in accordance with subsections A and B of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:~~

~~1. The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;~~

~~2. The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as the "electronic submission agent";~~

~~3. For each such natural person, a list of the type of electronic submissions under subsection A or B of this section for which authority is delegated to him; and~~

~~4. The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any electronic submission to the department or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6130 D shall be deemed to be an electronic submission by me. Until this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6130 D, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under 9VAC5-140-6130 is terminated."~~

D. A notice of delegation submitted under subsection C of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

E. Any electronic submission covered by the certification in subdivision C 4 of this section and made in accordance with a notice of delegation effective under subsection D of this section shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

F. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to review information in the CO_2 allowance tracking system under this part.

G. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to review information in the CO_2 allowance tracking system under this part.

H. To delegate authority to review information in the CO_2 allowance tracking system in accordance with subsections F and G of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

1. The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

2. The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as the "reviewer";

3. For each such natural person, a list of the type of information under subsection F or G of this section for which authority is delegated to him; and

4. The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any information that is reviewed by a natural person identified in this notice of delegation and of a type listed for such information accessible by the reviewer in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subsection I of this section shall be deemed to be a reviewer by me. Until this notice of delegation is superseded by another notice of delegation under subsection I of this section, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under this section is terminated."

I. A notice of delegation submitted under subsection H of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified reviewer, add a new reviewer, or eliminate entirely any delegation of authority.

~~Article 3~~

~~Permits~~

9VAC5-140-6140. ~~CO2 budget permit requirements.~~ (Repealed.)

~~Article 3~~
~~Permits~~

~~A. Each CO_2 budget source shall have a permit issued by the department pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation).~~

~~B. Each CO_2 budget permit shall contain all applicable CO_2 Budget Trading Program requirements and shall be a complete and distinguishable portion of the permit under subsection A of this section.~~

9VAC5-140-6150. ~~Submission of CO2 budget permit applications.~~ (Repealed.)

~~For any CO_2 budget source, the CO_2 authorized account representative shall submit a complete CO_2 budget permit application under 9VAC5-140-6160 covering such CO_2 budget source to the department by the later of January 1, 2021, or 12 months before the date on which the CO_2 budget source, or a new unit at the source, commences operation.~~

9VAC5-140-6160. ~~Information requirements for CO2 budget permit applications.~~ (Repealed.)

~~A complete CO_2 budget permit application shall include the following elements concerning the CO_2 budget source for which the application is submitted, in a format prescribed by the department:~~

~~1. Identification of the CO_2 budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration of the U.S. Department of Energy if applicable;~~

~~2. Identification of each CO_2 budget unit at the CO_2 budget source; and~~

~~3. The standard requirements under 9VAC5-140-6050.~~

~~Article 4~~

~~Compliance Certification~~

9VAC5-140-6170. ~~Compliance certification report.~~ (Repealed.)

~~Article 4~~
~~Compliance Certification~~

~~A. For each control period in which a CO_2 budget source is subject to the CO_2 requirements of 9VAC5-140-6050 C, the CO_2 authorized account representative of the source shall submit to the department by March 1 following the relevant control period, a compliance certification report. A compliance certification report is not required as part of the compliance obligation during an interim control period.~~

~~B. The CO_2 authorized account representative shall include in the compliance certification report under subsection A of this section the following elements, in a format prescribed by the department:~~

~~1. Identification of the source and each CO_2 budget unit at the source;~~

~~2. At the CO_2 authorized account representative's option, the serial numbers of the CO_2 allowances that are to be deducted from the source's compliance account under 9VAC5-140-6260 for the control period; and~~

~~3. The compliance certification under subsection C of this section.~~

C. In the compliance certification report under subsection A of this section, the CO_2 authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the CO_2 budget units at the source in compliance with the CO_2 Budget Trading Program, whether the source and each CO_2 budget unit at the source for which the compliance certification is submitted was operated during the calendar years covered by the report in compliance with the requirements of the CO_2 Budget Trading Program, including:

1. Whether the source was operated in compliance with the CO_2 requirements of 9VAC5-140-6050 C;

2. Whether the monitoring plan applicable to each unit at the source has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute CO_2 emissions to the unit, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part;

3. Whether all the CO_2 emissions from the units at the source were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

4. Whether the facts that form the basis for certification under Article 8 (9VAC5-140-6330 et seq.) of this part of each monitor at each unit at the source, or for using an excepted monitoring method or alternative monitoring method approved under Article 8 (9VAC5-140-6330 et seq.) of this part, if any, have changed; and

5. If a change is required to be reported under subdivision 4 of this subsection, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

9VAC5-140-6180. ~~Action on compliance certifications.~~ (Repealed.)

A. The department or its agent may review and conduct independent audits concerning any compliance certification or any other submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions.

B. The department or its agent may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on the information in the compliance certifications or other submissions, as adjusted under subsection A of this section.

Article 5

CO_2 Allowance Allocations

9VAC5-140-6190. ~~Base budgets.~~ (Repealed.)

Article 5

CO_2 Allowance Allocations

A. The Virginia CO_2 Budget Trading Program base budget shall be as follows:

1.

For 2021, the Virginia CO_2 Budget Trading Program base budget is 27.16 million tons.

2. For 2022, the Virginia CO_2 Budget Trading Program base budget is 26.32 million tons.

3. For 2023, the Virginia CO_2 Budget Trading Program base budget is 25.48 million tons.

4. For 2024, the Virginia CO_2 Budget Trading Program base budget is 24.64 million tons.

5. For 2025, the Virginia CO_2 Budget Trading Program base budget is 23.80 million tons.

6. For 2026, the Virginia CO_2 Budget Trading Program base budget is 22.96 million tons.

7. For 2027, the Virginia CO_2 Budget Trading Program base budget is 22.12 million tons.

8. For 2028, the Virginia CO_2 Budget Trading Program base budget is 21.28 million tons.

9. For 2029, the Virginia CO_2 Budget Trading Program base budget is 20.44 million tons.

10. For 2030, the Virginia CO_2 Budget Trading Program base budget is 19.60 million tons.

B.

For 2031 and each succeeding calendar year, the Virginia CO_2 Budget Trading Program base budget is 19.60 million tons unless modified as a result of a program review and future regulatory action.

9VAC5-140-6200. Undistributed and unsold conditional CO2 allowances. (Repealed.)

A. The department will retire undistributed CO_2 allowances at the end of each control period.

B. The department will retire unsold CO_2 allowances at the end of each control period.

9VAC5-140-6210. CO2 allowance allocations. (Repealed.)

A. The department will allocate the Virginia CO_2 Budget Trading Program base budget CO_2 allowances to the Virginia Auction Account.

B. For allocation years 2021 through 2030, the Virginia CO_2 Budget Trading Program adjusted budget shall be the maximum number of allowances available for allocation in a given allocation year, except for CO_2 CCR allowances.

C.

In the event that the CCR is triggered during an auction, the department will allocate CO_2 CCR allowances, separate from and additional to the Virginia CO_2 Budget Trading Program base budget set forth in 9VAC5-140-6190 to the Virginia Auction Account. The CCR allocation is for the purpose of containing the cost of CO_2 allowances. The department will allocate CO_2 CCR allowances as follows:

1.

On or before January 1, 2021, and each year thereafter, the department will allocate CO_2 CCR allowances equal to the quantity in Table 140-5A.

Table 140-5A
CO_2 CCR Allowances from 2021 Forward

2021	2.716 million tons
2022	2.632 million tons
2023	2.548 million tons
2024	2.464 million tons
2025	2.380 million tons
2026	2.296 million tons
2027	2.212 million tons

2028	2.128 million tons
2029	2.044 million tons
2030 and each year thereafter	1.960 million tons

2. CCR allowances allocated for a calendar year will be automatically transferred to the Virginia Auction Account to be auctioned. Following each auction, all CO_2 CCR allowances sold at auction will be transferred to winning bidders' accounts as CO_2 CCR allowances.

3. Unsold CO_2 CCR allowances will remain in the Virginia Auction Account to be re-offered for sale at auction within the same calendar year. CO_2 CCR allowances remaining unsold at the end of the calendar year in which they were originated will be made unavailable for sale at future auctions.

D. In the event that the ECR is triggered during an auction, the department will authorize its agent to withhold CO_2 allowances as needed. The department will further authorize its agent to convert and transfer any CO_2 allowances that have been withheld from any auction into the Virginia ECR account. The ECR withholding is for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs. The department's agent will withhold CO_2 ECR allowances as follows:

1. If the condition in 9VAC5-140-6420 C 1 is met at an auction, then the maximum number of CO_2 ECR allowances that will be withheld from that auction will be equal to the quantity shown in Table 140-5B minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the Virginia ECR account.

Table 140-5B ECR Allowances from 2021 Forward	
2021	2.716 million tons
2022	2.632 million tons
2023	2.548 million tons
2024	2.464 million tons
2025	2.380 million tons
2026	2.296 million tons
2027	2.212 million tons
2028	2.128 million tons
2029	2.044 million tons
2030 and each year thereafter	1.960 million tons

2. Allowances that have been transferred into the Virginia ECR account shall not be withdrawn.

E. The adjustment for banked allowances will be as follows. On March 15, 2021, the department may determine the adjustment for banked allowances quantity for allocation years 2021 through 2025 through the application of the following formula:

TABA = ((TA – TAE)/5) x RS%

Where:

TABA is the adjustment for banked allowances quantity in tons.

~~TA, adjustment, is the total quantity of allowances of vintage years prior to 2021 held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program but not including accounts opened by participating states, as reflected in the CO_2 Allowance Tracking System on March 15, 2021.~~

~~TAE, adjustment emissions, is the total quantity of 2018, 2019, and 2020 emissions from all CO_2 budget sources in all participating states, reported pursuant to CO_2 Budget Trading Program as reflected in the CO_2 Allowance Tracking System on March 15, 2021.~~

~~RS% is Virginia budget divided by the regional budget.~~

~~F. CO_2 Budget Trading Program adjusted budgets for 2021 through 2025 shall be determined as follows: on April 15, 2021, the department will determine the Virginia CO_2 Budget Trading Program adjusted budgets for the 2021 through 2025 allocation years by the following formula:~~

~~AB = BB – TABA~~

~~Where:~~

~~AB is the Virginia CO_2 Budget Trading Program adjusted budget.~~

~~BB is the Virginia CO_2 Budget Trading Program base budget.~~

~~TABA is the adjustment for banked allowances quantity in tons.~~

~~G. The department or its agent will publish the CO_2 trading program adjusted budgets for the 2021 through 2025 allocation years.~~

~~Article 6~~

~~CO_2 Allowance Tracking System~~

9VAC5-140-6220. ~~CO2 Allowance Tracking System accounts.~~ (Repealed.)

~~Article 6~~

~~CO_2 Allowance Tracking System~~

~~A. Consistent with 9VAC5-140-6230 A, the department or its agent will establish one compliance account for each CO_2 budget source. Allocations of CO_2 allowances pursuant to Article 5 (9VAC5-140-6190 et seq.) of this part and deductions or transfers of CO_2 allowances pursuant to 9VAC5-140-6180, 9VAC5-140-6260, 9VAC5-140-6280, or Article 7 (9VAC5-140-6300 et seq.) of this part will be recorded in the compliance accounts in accordance with this section.~~

~~B. Consistent with 9VAC5-140-6230 B, the department or its agent will establish, upon request, a general account for any person. Transfers of CO_2 allowances pursuant to Article 7 (9VAC5-140-6300 et seq.) of this part will be recorded in the general account in accordance with this article.~~

9VAC5-140-6230. ~~Establishment of accounts.~~ (Repealed.)

~~A. Upon receipt of a complete account certificate of representation under 9VAC5-140-6110, the department or its agent will establish an allowance account and a compliance account for each CO_2 budget source for which an account certificate of representation was submitted.~~

~~B. General accounts shall operate as follows.~~

~~1. Any person may apply to open a general account for the purpose of holding and transferring CO_2 allowances. An application for a general account may designate one and only one CO_2 authorized account representative and one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account~~

representative. A complete application for a general account shall be submitted to the department or its agent and shall include the following elements in a format prescribed by the department or its agent:

a. Name, address, email address, telephone number, and facsimile transmission number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

b. At the option of the CO_2 authorized account representative, organization name and type of organization;

c. A list of all persons subject to a binding agreement for the CO_2 authorized account representative or any CO_2 authorized alternate account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

d. The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: "I certify that I was selected as the CO_2 authorized account representative or the CO_2 authorized alternate account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the department or its agent or a court regarding the general account.";

e. The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed; and

f. Unless otherwise required by the department or its agent, documents of agreement referred to in the application for a general account shall not be submitted to the department or its agent. Neither the department nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

2. Authorization of the CO_2 authorized account representative shall be as follows:

a. Upon receipt by the department or its agent of a complete application for a general account under subdivision 1 of this subsection:

(1) The department or its agent will establish a general account for the person for whom the application is submitted.

(2) The CO_2 authorized account representative and any CO_2 authorized alternate account representative for the general account shall represent and, by his representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative or any CO_2 authorized alternate account representative and such person. Any such person shall be bound by any order or decision issued to the CO_2 authorized account representative or any CO_2 authorized alternate account representative by the department or its agent or a court regarding the general account.

(3) Any representation, action, inaction, or submission by any CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

b. Each submission concerning the general account shall be submitted, signed, and certified by the CO_2 authorized account representative or any CO_2 authorized alternate

account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission shall include the following certification statement by the CO_2 authorized account representative or any CO_2 authorized alternate account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

c. The department or its agent will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with subdivision 2 b of this subsection.

3. Changing CO_2 authorized account representative and CO_2 authorized alternate account representative, and changes in persons with ownership interest, shall be accomplished as follows:

a. The CO_2 authorized account representative for a general account may be changed at any time upon receipt by the department or its agent of a superseding complete application for a general account under subdivision 1 of this subsection. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the department or its agent receives the superseding application for a general account shall be binding on the new CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

b. The CO_2 authorized alternate account representative for a general account may be changed at any time upon receipt by the department or its agent of a superseding complete application for a general account under subdivision 1 of this subsection. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the department or its agent receives the superseding application for a general account shall be binding on the new alternate CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

c. In the event a new person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative, and the decisions, orders, actions, and inactions of the department or its agent, as if the new person were included in such list.

d. Within 30 days following any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or deletion of persons, the CO_2 authorized account representative or any CO_2 authorized

alternate account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CO_2 allowances in the general account to include the change.

4. Objections concerning CO_2 authorized account representative shall be governed as follows:

a. Once a complete application for a general account under subdivision 1 of this subsection has been submitted and received, the department or its agent will rely on the application unless and until a superseding complete application for a general account under subdivision 1 of this subsection is received by the department or its agent.

b. Except as provided in subdivisions 3 a and 3 b of this subsection, no objection or other communication submitted to the department or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative or the finality of any decision or order by the department or its agent under the CO_2 Budget Trading Program.

c. Neither the department nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

5. Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative shall be accomplished as follows:

a. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent provided for under this article and Article 7 (9VAC5-140-6300 et seq.) of this part.

b. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent provided for under this article and Article 7 (9VAC5-140-6300 et seq.) of this part.

c. To delegate authority to make an electronic submission to the department or its agent in accordance with subdivisions 5 a and 5 b of this subsection, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

(1) The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(2) The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as "electronic submission agent";

(3) For each such natural person, a list of the type of electronic submissions under subdivision 5 c (1) or 5 c (2) of this subsection for which authority is delegated to him; and

(4) The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any electronic submission to the department or its agent that is by a natural person

identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6230 B 5 d shall be deemed to be an electronic submission by me. Until this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6230 B 5 d, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under 9VAC5-140-6230 B 5 is terminated."

d. A notice of delegation submitted under subdivision 5 c of this subsection shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

e. Any electronic submission covered by the certification in subdivision 5 c (4) of this subsection and made in accordance with a notice of delegation effective under subdivision 5 d of this subsection shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

C. The department or its agent will assign a unique identifying number to each account established under subsection A or B of this section.

9VAC5-140-6240. ~~CO2 Allowance Tracking System responsibilities of CO2 authorized account representative.~~ (Repealed.)

Following the establishment of a COATS account, all submissions to the department or its agent pertaining to the account, including submissions concerning the deduction or transfer of CO_2 allowances in the account, shall be made only by the CO_2 authorized account representative for the account.

9VAC5-140-6250. ~~Recordation of CO2 allowance allocations.~~ (Repealed.)

A. By January 1 of each calendar year, the department or its agent will record in the following accounts:

1. In each CO_2 budget source's allowance account, the CO_2 allowances allocated to those sources by the department prior to being auctioned; and

2. In each CO_2 budget source's compliance account, the allowances purchased at auction by CO_2 budget units at the source under 9VAC5-140-6210 A.

B. Each year the department or its agent will record CO_2 allowances, as allocated to the unit under Article 5 (9VAC5-140-6190 et seq.) of this part, in the compliance account for the year after the last year for which CO_2 allowances were previously allocated to the compliance account. Each year, the department or its agent will also record CO_2 allowances, as allocated under Article 5 (9VAC5-140-6190 et seq.) of this part, in an allocation set-aside for the year after the last year for which CO_2 allowances were previously allocated to an allocation set-aside.

C. Serial numbers for allocated CO_2 allowances shall be managed as follows. When allocating CO_2 allowances to and recording them in an account, the department or its agent will assign each CO_2 allowance a unique identification number that will include digits identifying the year for which the CO_2 allowance is allocated.

9VAC5-140-6260. ~~Compliance.~~ (Repealed.)

~~A. CO_2 allowances that meet the following criteria are available to be deducted for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an interim control period.~~

~~1. The CO_2 allowances are of allocation years that fall within a prior control period, the same control period, or the same interim control period for which the allowances will be deducted.~~

~~2. The CO_2 allowances are held in the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that control period or interim control period or are transferred into the compliance account by a CO_2 allowance transfer correctly submitted for recordation under 9VAC5-140-6300 by the CO_2 allowance transfer deadline for that control period or interim control period.~~

~~3. For CO_2 offset allowances generated by other participating states, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an interim control period shall not exceed 3.3% of the CO_2 budget source's CO_2 emissions for that control period, or may not exceed 3.3% of 0.50 times the CO_2 budget source's CO_2 emissions for an interim control period, as determined in accordance with this article and Article 8 (9VAC5-140-6330 et seq.) of this part.~~

~~4. The CO_2 allowances are not necessary for deductions for excess emissions for a prior control period under subsection D of this section.~~

~~B. Following the recordation, in accordance with 9VAC5-140-6310, of CO_2 allowance transfers submitted for recordation in the CO_2 budget source's compliance account by the CO_2 allowance transfer deadline for a control period or an interim control period, the department or its agent will deduct CO_2 allowances available under subsection A of this section to cover the source's CO_2 emissions, as determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, for the control period or interim control period, as follows:~~

~~1. Until the amount of CO_2 allowances deducted equals the number of tons of total CO_2 emissions, or 0.50 times the number of tons of total CO_2 emissions for an interim control period, determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, from all CO_2 budget units at the CO_2 budget source for the control period or interim control period; or~~

~~2. If there are insufficient CO_2 allowances to complete the deductions in subdivision 1 of this subsection, until no more CO_2 allowances available under subsection A of this section remain in the compliance account.~~

~~C. Identification of available CO_2 allowances by serial number and default compliance deductions shall be managed as follows:~~

~~1. The CO_2 authorized account representative for a source's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period or interim control period in accordance with subsection B or D of this section. Such identification shall be made in the compliance certification report submitted in accordance with 9VAC5-140-6170.~~

~~2. The department or its agent will deduct CO_2 allowances for an interim control period or a control period from the CO_2 budget source's compliance account, in the absence of an identification or in the case of a partial identification of available CO_2 allowances by serial number under subdivision 1 of this subsection, as follows: Any CO_2 allowances that are available for deduction under subdivision 1 of this subsection. CO_2 allowances shall be~~

deducted in chronological order (i.e., CO_2 allowances from earlier allocation years shall be deducted before CO_2 allowances from later allocation years). In the event that some, but not all, CO_2 allowances from a particular allocation year are to be deducted, CO_2 allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances.

D. Deductions for excess emissions shall be managed as follows.

1. After making the deductions for compliance under subsection B of this section, the department or its agent will deduct from the CO_2 budget source's compliance account a number of CO_2 allowances equal to three times the number of the source's excess emissions. In the event that a source has insufficient CO_2 allowances to cover three times the number of the source's excess emissions, the source shall be required to immediately transfer sufficient allowances into its compliance account.

2. Any CO_2 allowance deduction required under subdivision 1 of this subsection shall not affect the liability of the owners and operators of the CO_2 budget source or the CO_2 budget units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under applicable state law. The following guidelines will be followed in assessing fines, penalties, or other obligations:

a. For purposes of determining the number of days of violation, if a CO_2 budget source has excess emissions for a control period, each day in the control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

b. Each ton of excess emissions is a separate violation.

c. For purposes of determining the number of days of violation, if a CO_2 budget source has excess interim emissions for an interim control period, each day in the interim control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

d. Each ton of excess interim emissions is a separate violation.

3. The propriety of the department's determination that a CO_2 budget source had excess emissions and the concomitant deduction of CO_2 allowances from that CO_2 budget source's account may be later challenged in the context of the initial administrative enforcement, or any civil or criminal judicial action arising from or encompassing that excess emissions violation. The commencement or pendency of any administrative enforcement, or civil or criminal judicial action arising from or encompassing that excess emissions violation will not act to prevent the department or its agent from initially deducting the CO_2 allowances resulting from the department's original determination that the relevant CO_2 budget source has had excess emissions. Should the department's determination of the existence or extent of the CO_2 budget source's excess emissions be revised either by a settlement or final conclusion of any administrative or judicial action, the department will act as follows:

a. In any instance where the department's determination of the extent of excess emissions was too low, the department will take further action under subdivisions 1 and 2 of this subsection to address the expanded violation.

b. In any instance where the department's determination of the extent of excess emissions was too high, the department will distribute to the relevant CO_2 budget source a number of CO_2 allowances equaling the number of CO_2 allowances deducted which are attributable to the difference between the original and final quantity of excess emissions. Should such CO_2 budget source's compliance account no longer exist, the

~~CO_2 allowances will be provided to a general account selected by the owner or operator of the CO_2 budget source from which they were originally deducted.~~

~~E. The department or its agent will record in the appropriate compliance account all deductions from such an account pursuant to subsections B and D of this section.~~

~~F. Action by the department on submissions shall be as follows:~~

~~1. The department may review and conduct independent audits concerning any submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the submissions.~~

~~2. The department may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on information in the submissions, as adjusted under subdivision 1 of this subsection.~~

9VAC5-140-6270. ~~Banking.~~ (Repealed.)

~~Each CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under 9VAC5-140-6180, 9VAC5-140-6260, 9VAC5-140-6280, or Article 7 (9VAC5-140-6300 et seq.) of this part.~~

9VAC5-140-6280. ~~Account error.~~ (Repealed.)

~~The department or its agent may, at its sole discretion and on its own motion, correct any error in any COATS account. Within 10 business days of making such correction, the department or its agent will notify the CO_2 authorized account representative for the account.~~

9VAC5-140-6290. ~~Closing of general accounts.~~ (Repealed.)

~~A. A CO_2 authorized account representative of a general account may instruct the department or its agent to close the account by submitting a statement requesting deletion of the account from the COATS and by correctly submitting for recordation under 9VAC5-140-6300 a CO_2 allowance transfer of all CO_2 allowances in the account to one or more other COATS accounts.~~

~~B. If a general account shows no activity for a period of one year or more and does not contain any CO_2 allowances, the department or its agent may notify the CO_2 authorized account representative for the account that the account will be closed in the COATS 30 business days after the notice is sent. The account will be closed after the 30-day period unless before the end of the 30-day period the department or its agent receives a correctly submitted transfer of CO_2 allowances into the account under 9VAC5-140-6300 or a statement submitted by the CO_2 authorized account representative demonstrating to the satisfaction of the department or its agent good cause as to why the account should not be closed. The department or its agent will have sole discretion to determine if the owner or operator of the unit demonstrated that the account should not be closed.~~

~~Article 7~~

~~CO_2 Allowance Transfers~~

9VAC5-140-6300. ~~Submission of CO2 allowance transfers.~~ (Repealed.)

~~Article 7~~

~~CO_2 Allowance Transfers~~

~~The CO_2 authorized account representatives seeking recordation of a CO_2 allowance transfer shall submit the transfer to the department or its agent. To be considered correctly submitted, the CO_2 allowance transfer shall include the following elements in a format specified by the department or its agent:~~

~~1. The numbers identifying both the transferor and transferee accounts;~~

~~2. A specification by serial number of each CO_2 allowance to be transferred;~~

3. The printed name and signature of the CO_2 authorized account representative of the transferor account and the date signed;

4. The date of the completion of the last sale or purchase transaction for the allowance, if any; and

5. The purchase or sale price of the allowance that is the subject of a sale or purchase transaction under subdivision 4 of this section.

9VAC5-140-6310. ~~Recordation.~~ (Repealed.)

A. Within five business days of receiving a CO_2 allowance transfer, except as provided in subsection B of this section, the department or its agent will record a CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified by the request, provided that:

1. The transfer is correctly submitted under 9VAC5-140-6300; and

2. The transferor account includes each CO_2 allowance identified by serial number in the transfer.

B. A CO_2 allowance transfer into or out of a compliance account that is submitted for recordation following the CO_2 allowance transfer deadline and that includes any CO_2 allowances that are of allocation years that fall within a control period prior to or the same as the control period to which the CO_2 allowance transfer deadline applies will not be recorded until after completion of the process pursuant to 9VAC5-140-6260 B.

C. Where a CO_2 allowance transfer submitted for recordation fails to meet the requirements of subsection A of this section, the department or its agent will not record such transfer.

9VAC5-140-6320. ~~Notification.~~ (Repealed.)

A. Within five business days of recordation of a CO_2 allowance transfer under 9VAC5-140-6310, the department or its agent will notify each party to the transfer. Notice will be given to the CO_2 authorized account representatives of both the transferor and transferee accounts.

B. Within 10 business days of receipt of a CO_2 allowance transfer that fails to meet the requirements of 9VAC5-140-6310 A, the department or its agent will notify the CO_2 authorized account representatives of both accounts subject to the transfer of (i) a decision not to record the transfer and (ii) the reasons for such nonrecordation.

C. Nothing in this section shall preclude the submission of a CO_2 allowance transfer for recordation following notification of nonrecordation.

9VAC5-140-6325. ~~Life-of-the-unit contractual arrangements.~~ (Repealed.)

A. A power purchaser entered into a life-of-the-unit contractual arrangement as described in subdivision b of the definition of "life-of-the-unit contractual arrangement" with a CO_2 budget source or unit shall be responsible for acquiring and transferring all allowances to the CO_2 budget source or unit that are necessary for demonstrating compliance with the CO_2 budget trading program.

B. The CO_2 budget source or unit shall provide a copy of the energy conversion or energy tolling agreement to the department within six months of July 10, 2020. If such agreement is subject to third-party disclosure restrictions, the CO_2 budget source or unit shall provide purchaser within 10 days prior written notice of its intention to disclose the agreement to the department and request confidential treatment from the public disclosure of such agreement. The department will grant a request for confidential treatment pursuant to applicable statutory and regulatory requirements addressing confidential information.

C. The CO_2 budget source or unit shall be responsible for compliance with and otherwise be subject to all other requirements of this part and the CO_2 budget trading program.

~~Article 8~~

~~Monitoring, Reporting, and Recordkeeping~~

9VAC5-140-6330. ~~General requirements.~~ (Repealed.)

~~Article 8~~

~~Monitoring, Reporting, and Recordkeeping~~

~~A. The owners and operators, and to the extent applicable, the CO_2 authorized account representative of a CO_2 budget unit shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this section and all applicable sections of 40 CFR Part 75. Where referenced in this article, the monitoring requirements of 40 CFR Part 75 shall be adhered to in a manner consistent with the purpose of monitoring and reporting CO_2 mass emissions pursuant to this part. For purposes of complying with such requirements, the definitions in 9VAC5-140-6020 and in 40 CFR 72.2 shall apply, and the terms "affected unit," "designated representative," and "CEMS" in 40 CFR Part 75 shall be replaced by the terms "CO_2 budget unit," "CO_2 authorized account representative," and "CEMS," respectively, as defined in 9VAC5-140-6020. For units not subject to an Acid Rain emissions limitation, the term "administrator" in 40 CFR Part 75 shall be replaced with "the department or its agent." Owners or operators of a CO_2 budget unit who monitor a non-CO_2 budget unit pursuant to the common, multiple, or bypass stack procedures in 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16 (b)(2)(ii)(B) pursuant to 40 CFR 75.13, for purposes of complying with this part, shall monitor and report CO_2 mass emissions from such non-CO_2 budget units according to the procedures for CO_2 budget units established in this article.~~

~~B. The owner or operator of each CO_2 budget unit shall meet the following general requirements for installation, certification, and data accounting.~~

~~1. Install all monitoring systems necessary to monitor CO_2 mass emissions in accordance with 40 CFR Part 75, except for equation G-1. Equation G-1 in Appendix G shall not be used to determine CO_2 emissions under this part. This may require systems to monitor CO_2 concentration, stack gas flow rate, O_2 concentration, heat input, and fuel flow rate.~~

~~2. Successfully complete all certification tests required under 9VAC5-140-6340 and meet all other requirements of this section and 40 CFR Part 75 applicable to the monitoring systems under subdivision 1 of this subsection.~~

~~3. Record, report, and quality-assure the data from the monitoring systems under subdivision 1 of this subsection.~~

~~C. The owner or operator shall meet the monitoring system certification and other requirements of subsection B of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under subdivision B 1 of this section on and after the following dates:~~

~~1. The owner or operator of a CO_2 budget unit, except for a CO_2 budget unit under subdivision 2 of this subsection, shall comply with the requirements of this section by January 1, 2021.~~

~~2. The owner or operator of a CO_2 budget unit that commences commercial operation July 1, 2021, shall comply with the requirements of this section by (i) January 1, 2022, or (ii) the earlier of 90 unit operating days after the date on which the unit commences commercial operation or 180 calendar days after the date on which the unit commences commercial operation.~~

~~3. For the owner or operator of a CO_2 budget unit for which construction of a new stack or flue installation is completed after the applicable deadline under subdivision 1 or 2 of this subsection by the earlier of (i) 90 unit operating days after the date on which emissions~~

first exit to the atmosphere through the new stack or flue or (ii) 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue.

D. Data shall be reported as follows:

1. Except as provided in subdivision 2 of this subsection, the owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in subsection C of this section for any monitoring system under subdivision B 1 of this section shall, for each such monitoring system, determine, record, and report maximum potential, or as appropriate minimum potential, values for CO_2 concentration, CO_2 emissions rate, stack gas moisture content, fuel flow rate, heat input, and any other parameter required to determine CO_2 mass emissions in accordance with 40 CFR 75.31(b)(2) or (c)(3) or Section 2.4 of Appendix D of 40 CFR Part 75 as applicable.

2. The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in subdivision C 3 of this section for any monitoring system under subdivision B 1 of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in Subpart D, or Appendix D of 40 CFR Part 75, in lieu of the maximum potential, or as appropriate minimum potential, values for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under subdivision C 3 of this section.

a. CO_2 budget units subject to an Acid Rain emissions limitation or CSAPR NO_X Ozone Season Trading Program that qualify for the optional SO_2, NO_x, and CO_2 (for Acid Rain) or NO_X (for CSAPR NO_X Ozone Season Trading Program) emissions calculations for low mass emissions (LME) units under 40 CFR 75.19 and report emissions for such programs using the calculations under 40 CFR 75.19, shall also use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

b. CO_2 budget units subject to an Acid Rain emissions limitation that do not qualify for the optional SO_2, NO_x, and CO_2 (for Acid Rain) or NO_X (for CSAPR NO_X Ozone Season Trading Program) emissions calculations for LME units under 40 CFR 75.19 shall not use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

c. CO_2 budget units not subject to an Acid Rain emissions limitation shall qualify for the optional CO_2 emissions calculation for LME units under 40 CFR 75.19, provided that they emit less than 100 tons of NO_X annually and no more than 25 tons of SO_2 annually.

3. The owner or operator of a CO_2 budget unit shall report net-electric output data to the department as required by Article 5 (9VAC5-140-6190 et seq.) of this part.

E. Prohibitions shall be as follows.

1. No owner or operator of a CO_2 budget unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required CEMS without having obtained prior written approval in accordance with 9VAC5-140-6380.

2. No owner or operator of a CO_2 budget unit shall operate the unit so as to discharge, or allow to be discharged, CO_2 emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this article and 40 CFR Part 75.

3. No owner or operator of a CO_2 budget unit shall disrupt the CEMS, any portion thereof, or any other approved emissions monitoring method, and thereby avoid monitoring and recording CO_2 mass emissions discharged into the atmosphere, except for periods of

~~recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this article and 40 CFR Part 75.~~

~~4. No owner or operator of a CO_2 budget unit shall retire or permanently discontinue use of the CEMS, any component thereof, or any other approved emissions monitoring system under this article, except under any one of the following circumstances:~~

~~a. The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this article and 40 CFR Part 75, by the department for use at that unit that provides emissions data for the same pollutant or parameter as the retired or discontinued monitoring system; or~~

~~b. The CO_2 authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with 9VAC5-140-6340 D 3 a.~~

9VAC5-140-6340. ~~Initial certification and recertification procedures.~~ (Repealed.)

~~A. The owner or operator of a CO_2 budget unit shall be exempt from the initial certification requirements of this section for a monitoring system under 9VAC5-140-6330 B 1 if the following conditions are met:~~

~~1. The monitoring system has been previously certified in accordance with 40 CFR Part 75; and~~

~~2. The applicable quality-assurance and quality-control requirements of 40 CFR 75.21 and Appendix B and Appendix D of 40 CFR Part 75 are fully met for the certified monitoring system described in subdivision 1 of this subsection.~~

~~B. The recertification provisions of this section shall apply to a monitoring system under 9VAC5-140-6330 B 1 exempt from initial certification requirements under subsection A of this section.~~

~~C. Notwithstanding subsection A of this section, if the administrator has previously approved a petition under 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16(b)(2)(ii)(B) as pursuant to 40 CFR 75.13 for apportioning the CO_2 emissions rate measured in a common stack or a petition under 40 CFR 75.66 for an alternative requirement in 40 CFR Part 75, the CO_2 authorized account representative shall submit the petition to the department under 9VAC5-140-6380 A to determine whether the approval applies under this program.~~

~~D. Except as provided in subsection A of this section, the owner or operator of a CO_2 budget unit shall comply with the following initial certification and recertification procedures for a CEMS and an excepted monitoring system under Appendix D of 40 CFR Part 75 and under 9VAC5-140-6330 B 1. The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology in 40 CFR 75.19 or that qualifies to use an alternative monitoring system under Subpart E of 40 CFR Part 75 shall comply with the procedures in subsection E or F of this section, respectively.~~

~~1. For initial certification, the owner or operator shall ensure that each CEMS required under 9VAC5-140-6330 B 1, which includes the automated DAHS, successfully completes all of the initial certification testing required under 40 CFR 75.20 by the applicable deadlines specified in 9VAC5-140-6330 C. In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this article in a location where no such monitoring system was previously installed, initial certification in accordance with 40 CFR 75.20 is required.~~

~~2. For recertification, the following requirements shall apply.~~

~~a. Whenever the owner or operator makes a replacement, modification, or change in a certified CEMS under 9VAC5-140-6330 B 1 that the administrator or the department~~

~~determines significantly affects the ability of the system to accurately measure or record CO_2 mass emissions or to meet the quality-assurance and quality-control requirements of 40 CFR 75.21 or Appendix B to 40 CFR Part 75, the owner or operator shall recertify the monitoring system according to 40 CFR 75.20(b).~~

~~b. For systems using stack measurements such as stack flow, stack moisture content, CO_2 or O_2 monitors, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the administrator or the department determines to significantly change the flow or concentration profile, the owner or operator shall recertify the CEMS according to 40 CFR 75.20(b). Examples of changes that require recertification include replacement of the analyzer, change in location or orientation of the sampling probe or site, or change of flow rate monitor polynomial coefficients.~~

~~3. The approval process for initial certifications and recertification shall be as follows: subdivisions 3 a through 3 d of this subsection apply to both initial certification and recertification of a monitoring system under 9VAC5-140-6330 B 1. For recertifications, replace the words "certification" and "initial certification" with the word "recertification," replace the word "certified" with "recertified," and proceed in the manner prescribed in 40 CFR 75.20(b)(5) and (g)(7) in lieu of subdivision 3 e of this subsection.~~

~~a. The CO_2 authorized account representative shall submit to the department or its agent, the appropriate EPA Regional Office and the administrator a written notice of the dates of certification in accordance with 9VAC5-140-6360.~~

~~b. The CO_2 authorized account representative shall submit to the department or its agent a certification application for each monitoring system. A complete certification application shall include the information specified in 40 CFR 75.63.~~

~~c. The provisional certification date for a monitor shall be determined in accordance with 40 CFR 75.20(a)(3). A provisionally certified monitor may be used under the CO_2 Budget Trading Program for a period not to exceed 120 days after receipt by the department of the complete certification application for the monitoring system or component thereof under subdivision 3 b of this subsection. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of 40 CFR Part 75, will be considered valid quality-assured data, retroactive to the date and time of provisional certification, provided that the department does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the department.~~

~~d. The department will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under subdivision 3 b of this subsection. In the event the department does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of 40 CFR Part 75 and is included in the certification application will be deemed certified for use under the CO_2 Budget Trading Program.~~

~~(1) If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR Part 75, then the department will issue a written notice of approval of the certification application within 120 days of receipt.~~

~~(2) If the certification application is incomplete, then the department will issue a written notice of incompleteness that sets a reasonable date by which the CO_2 authorized account representative shall submit the additional information required to complete the~~

certification application. If the CO_2 authorized account representative does not comply with the notice of incompleteness by the specified date, then the department may issue a notice of disapproval under subdivision 3 d (3) of this subsection. The 120-day review period shall not begin before receipt of a complete certification application.

(3) If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of 40 CFR Part 75, or if the certification application is incomplete and the requirement for disapproval under subdivision 3 d (2) of this subsection is met, then the department will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the department and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in subdivision 3 e of this subsection for each monitoring system or component thereof, which is disapproved for initial certification.

(4) The department may issue a notice of disapproval of the certification status of a monitor in accordance with 9VAC5-140-6350 B.

e. If the department issues a notice of disapproval of a certification application under subdivision 3 d (3) of this subsection or a notice of disapproval of certification status under subdivision 3 d (3) of this subsection, then:

(1) The owner or operator shall substitute the following values for each disapproved monitoring system, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under 40 CFR 75.20(a)(5)(i) or 40 CFR 75.20(g)(7): (i) for units using or intending to monitor for CO_2 mass emissions using heat input or for units using the low mass emissions excepted methodology under 40 CFR 75.19, the maximum potential hourly heat input of the unit; or (ii) for units intending to monitor for CO_2 mass emissions using a CO_2 pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO_2 and the maximum potential flow rate of the unit under Section 2.1 of Appendix A of 40 CFR Part 75;

(2) The CO_2 authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with subdivisions 3 a and 3 b of this subsection; and

(3) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the department's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

E. The owner or operator of a unit qualified to use the low mass emissions excepted methodology under 9VAC5-140-6330 D 3 shall meet the applicable certification and recertification requirements of 40 CFR 75.19(a)(2), 40 CFR 75.20(h), and this section. If the owner or operator of such a unit elects to certify a fuel flow meter system for heat input determinations, the owner or operator shall also meet the certification and recertification requirements in 40 CFR 75.20(g).

F. The CO_2 authorized account of each unit for which the owner or operator intends to use an alternative monitoring system approved by the administrator and, if applicable, the department under Subpart E of 40 CFR Part 75 shall comply with the applicable notification and application procedures of 40 CFR 75.20(f).

9VAC5-140-6350. ~~Out-of-control periods.~~ (Repealed.)

~~A. Whenever any monitoring system fails to meet the quality assurance/quality control (QA/QC) requirements or data validation requirements of 40 CFR Part 75, data shall be substituted using the applicable procedures in Subpart D or Appendix D of 40 CFR Part 75.~~

~~B. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under 9VAC5-140-6340 or the applicable provisions of 40 CFR Part 75, both at the time of the initial certification or recertification application submission and at the time of the audit, the department or administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this subsection, an audit shall be either a field audit or an audit of any information submitted to the department or the administrator. By issuing the notice of disapproval, the department or administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the initial certification or recertification procedures in 9VAC5-140-6340 for each disapproved monitoring system.~~

9VAC5-140-6360. ~~Notifications.~~ (Repealed.)

~~The CO_2 authorized account representative for a CO_2 budget unit shall submit written notice to the department and the administrator in accordance with 40 CFR 75.61.~~

9VAC5-140-6370. ~~Recordkeeping and reporting.~~ (Repealed.)

~~A. The CO_2 authorized account representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under 40 CFR 75.73, and the requirements of 9VAC5-140-6080 E.~~

~~B. The owner or operator of a CO_2 budget unit shall submit a monitoring plan in the manner prescribed in 40 CFR 75.62.~~

~~C. The CO_2 authorized account representative shall submit an application to the department within 45 days after completing all CO_2 monitoring system initial certification or recertification tests required under 9VAC5-140-6340, including the information required under 40 CFR 75.63 and 40 CFR 75.53(e) and (f).~~

~~D. The CO_2 authorized account representative shall submit quarterly reports, as follows:~~

~~1. The CO_2 authorized account representative shall report the CO_2 mass emissions data for the CO_2 budget unit, in an electronic format prescribed by the department unless otherwise prescribed by the department for each calendar quarter.~~

~~2. The CO_2 authorized account representative shall submit each quarterly report to the department or its agent within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in Subpart H of 40 CFR Part 75 and 40 CFR 75.64. Quarterly reports shall be submitted for each CO_2 budget unit, or group of units using a common stack, and shall include all of the data and information required in Subpart G of 40 CFR Part 75, except for opacity, heat input, NO_x, and SO_2 provisions.~~

~~3. The CO_2 authorized account representative shall submit to the department or its agent a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:~~

a. The monitoring data submitted were recorded in accordance with the applicable requirements of this article and 40 CFR Part 75, including the quality assurance procedures and specifications;

b. For a unit with add-on CO_2 emissions controls and for all hours where data are substituted in accordance with 40 CFR 75.34(a)(1), the add-on emissions controls were operating within the range of parameters listed in the QA/QC program under Appendix B of 40 CFR Part 75 and the substitute values do not systematically underestimate CO_2 emissions; and

c. The CO_2 concentration values substituted for missing data under Subpart D of 40 CFR Part 75 do not systematically underestimate CO_2 emissions.

9VAC5-140-6380. ~~Petitions.~~ (Repealed.)

A. Except as provided in subsection C of this section, the CO_2 authorized account representative of a CO_2 budget unit that is subject to an Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this article only to the extent that the petition is approved in writing by the administrator, and subsequently approved in writing by the department.

B. Petitions for a CO_2 budget unit that is not subject to an Acid Rain emissions limitation shall meet the following requirements.

1. The CO_2 authorized account representative of a CO_2 budget unit that is not subject to an Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this article only to the extent that the petition is approved in writing by the administrator and subsequently approved in writing by the department.

2. In the event that the administrator declines to review a petition under subdivision 1 of this subsection, the CO_2 authorized account representative of a CO_2 budget unit that is not subject to an Acid Rain emissions limitation may submit a petition to the department requesting approval to apply an alternative to any requirement of this article. That petition shall contain all of the relevant information specified in 40 CFR 75.66. Application of an alternative to any requirement of this article is in accordance with this article only to the extent that the petition is approved in writing by the department.

C. The CO_2 authorized account representative of a CO_2 budget unit that is subject to an Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of 40 CFR 75.72 or a CO_2 concentration CEMS used under 40 CFR 75.71(a)(2). Application of an alternative to any such requirement is in accordance with this article only to the extent the petition is approved in writing by the administrator and subsequently approved in writing by the department.

9VAC5-140-6390. ~~[Reserved].~~ (Repealed.)

9VAC5-140-6400. ~~[Reserved].~~ (Repealed.)

~~Article 9~~

~~Auction of CO_2 CCR and ECR Allowances~~

9VAC5-140-6410. ~~Purpose.~~ (Repealed.)

~~Article 9~~

~~Auction of CO_2 CCR and ECR Allowances~~

~~The following requirements shall apply to each allowance auction. The department or its agent may specify additional information in the auction notice for each auction. Such additional information may include the time and location of the auction, auction rules, registration deadlines, and any additional information deemed necessary or useful.~~

9VAC5-140-6420. ~~General requirements.~~ (Repealed.)

~~A. The department's agent will include the following information in the auction notice for each auction:~~

~~1. The number of CO_2 allowances offered for sale at the auction, not including any CO_2 CCR allowances;~~

~~2. The number of CO_2 CCR allowances that will be offered for sale at the auction if the condition of subdivision B 1 of this section is met;~~

~~3. The minimum reserve price for the auction;~~

~~4. The CCR trigger price for the auction;~~

~~5. The maximum number of CO_2 allowances that may be withheld from sale at the auction if the condition of subdivision D 1 of this section is met; and~~

~~6. The ECR trigger price for the auction.~~

~~B. The department's agent will follow these rules for the sale of CO_2 CCR allowances.~~

~~1. CO_2 CCR allowances shall only be sold at an auction in which total demand for allowances, above the CCR trigger price, exceeds the number of CO_2 allowances available for purchase at the auction, not including any CO_2 CCR allowances.~~

~~2. If the condition of subdivision 1 of this subsection is met at an auction, then the number of CO_2 CCR allowances offered for sale by the department or its agent at the auction shall be equal to the number of CO_2 CCR allowances in the Virginia Auction Account at the time of the auction.~~

~~3. After all of the CO_2 CCR allowances in the Virginia Auction Account have been sold in a given calendar year, no additional CO_2 CCR allowances will be sold at any auction for the remainder of that calendar year, even if the condition of subdivision 1 of this subsection is met at an auction.~~

~~4. At an auction in which CO_2 CCR allowances are sold, the reserve price for the auction shall be the CCR trigger price.~~

~~5. If the condition of subdivision 1 of this subsection is not satisfied, no CO_2 CCR allowances shall be offered for sale at the auction, and the reserve price for the auction shall be equal to the minimum reserve price.~~

~~C. The department's agent shall implement the reserve price as follows: (i) no allowances shall be sold at any auction for a price below the reserve price for that auction and (ii) if the total demand for allowances at an auction is less than or equal to the total number of allowances made available for sale in that auction, then the auction clearing price for the auction shall be the reserve price.~~

~~D. The department's agent will meet the following rules for the withholding of CO_2 ECR allowances from an auction.~~

~~1. CO_2 ECR allowances shall only be withheld from an auction if the demand for allowances would result in an auction clearing price that is less than the ECR trigger price prior to the withholding from the auction of any ECR allowances.~~

~~2. If the condition in subdivision 1 of this subsection is met at an auction, then the maximum number of CO_2 ECR allowances that may be withheld from that auction will be equal to the quantity shown in Table 140-5B of 9VAC5-140-6210 E minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the Virginia ECR Account.~~

9VAC5-140-6440. ~~Program monitoring and review.~~ (Repealed.)

~~Article 10~~

~~Program Monitoring and Review~~

~~In conjunction with the CO_2 Budget Trading Program program monitoring and review process, the department will evaluate impacts of the program specific to Virginia, including economic, energy, and environmental impacts and impacts on vulnerable and environmental justice and underserved communities. The department will, in evaluating the impacts on environmental justice communities, including low income, minority, and tribal communities, develop and implement a plan to ensure increased participation of environmental justice communities in the review.~~

Form: TH-05
April 2020

townhall.virginia.gov

Emergency Regulation and Notice of Intended Regulatory Action (NOIRA) Agency Background Document

Agency name	State Air Pollution Control Board
Virginia Administrative Code (VAC) Chapter citation(s)	Part VII of 9VAC5-140
VAC Chapter title(s)	Regulation for Emissions Trading
Action title	Repeal CO_2 Budget Trading Program as required by Executive Order 9 (Revision A22-E)
Date this document prepared	

This information is required for executive branch review and the Virginia Registrar of Regulations, pursuant to the Virginia Administrative Process Act (APA), Executive Order 14 (as amended, July 16, 2018), the Regulations for Filing and Publishing Agency Regulations (1VAC7-10), and the *Form and Style Requirements for the Virginia Register of Regulations and Virginia Administrative Code*.

Brief Summary

Provide a brief summary (preferably no more than 2 or 3 paragraphs) of the subject matter, intent, and goals of this this regulatory change (i.e., new regulation, amendments to an existing regulation, or repeal of an existing regulation). Alert the reader to all substantive matters or changes. If applicable, generally describe the existing regulation.

Executive Order 9 (2022), "Protecting Ratepayers from the Rising Cost of Living Due to the Regional Greenhouse Gas Initiative," requires that the department re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) and immediately begin regulatory processes to end it. Specifically, the order requires that the department develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal the implementing regulation implementing participation in RGGI (Part VII of 9VAC5-140), and take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the board's authority pursuant to § 10.1-1308 of the Code of Virginia.

Acronyms and Definitions

Define all acronyms used in this form, and any technical terms that are not also defined in the "Definitions" section of the regulation.

EO-9 - Executive Order 9 (2022)
RGGI - Regional Greenhouse Gas Initiative

Mandate and Impetus (Necessity for Emergency)

Explain why this rulemaking is an emergency situation in accordance with § 2.2-4011 A and B of the Code of Virginia. In doing so, either:

a) Indicate whether the Governor's Office has already approved the use of emergency regulatory authority for this regulatory change.
b) Provide specific citations to Virginia statutory law, the appropriation act, federal law, or federal regulation that require that a regulation be effective in 280 days or less from its enactment.

As required by § 2.2-4011, also describe the nature of the emergency and of the necessity for this regulatory change. In addition, delineate any potential issues that may need to be addressed as part of this regulatory change

The Governor's Office has already approved the use of emergency regulatory authority for this regulatory change via EO-9. The nature of the emergency and the necessity for this regulatory change are described in EO-9 as follows:

> Reliable and affordable access to electricity is imperative to the health and safety of all Virginians. Our hospitals, schools, businesses, and homes all rely on this essential service. And the unpredictable and rising cost of electricity poses a significant and immediate threat to our Commonwealth and its citizens. In 2019, alone, over 100,000 Virginian households required Energy Assistance with a cost of $46 million to the Commonwealth.
>
> Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) risks contributing to the increased cost of electricity for our citizens. Virginia's utilities have sold over $227 million in allowances in 2021 during the RGGI auctions, doubling the initial estimates. Those utilities are allowed to pass on the costs of purchasing allowances to their ratepayers. Under the initial bill "RGGI rider" created for Dominion Energy customers, typical residential customer bills were increased by $2.39 a month and the typical industrial customer bill by was raised by $1,554 per month. In a filling before the State Corporation Commission, Dominion Energy stated that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.
>
> Simply stated, the benefits of RGGI have not materialized, while the costs have skyrocketed. Re-evaluation of the Initiative represents a meaningful step toward alleviating this financial burden on the Commonwealth's businesses and households. Regulations must be evaluated in view of the costs and benefits to all Virginians.

Legal Basis

Identify (1) the promulgating agency, and (2) the state and/or federal legal authority for the regulatory change, including the most relevant citations to the Code of Virginia or Acts and Assembly chapter number(s), if applicable. Your citation must include a specific provision, if any, authorizing the

promulgating agency to regulate this specific subject or program, as well as a reference to the agency's overall regulatory authority.

Statutory Authority

Section 10.1-1308 of the Virginia Air Pollution Control Law (Title 10.1, Chapter 13 of the Code of Virginia) authorizes the State Air Pollution Control Board to promulgate regulations abating, controlling and prohibiting air pollution in order to protect public health and welfare.

Promulgating Entity

The promulgating entity for this regulation is the State Air Pollution Control Board.

State Requirements

The specific directive of EO-9 states:

> . . . I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural and Historic Resources, to take the following actions in accordance with the provisions and requirements of § 10.1-1300, et seq. and § 2.2-4000, et seq. of the Code of Virginia:
>
> > 1. Provide me a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data, within 30 days.
> >
> > 2. During this same period, develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal 9VAC5-140.
> >
> > 3. During this same period, take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the Code of Virginia.
> >
> > 4. During this same period, notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

This NOIRA is intended to implement items 2 and 3 of the directive.

Purpose

Describe the specific reasons why the agency has determined that this regulation is essential to protect the health, safety, or welfare of citizens. In addition, explain any potential issues that may need to be addressed as the regulation is developed.

As described in the Mandate and Impetus section of this document, EO-9 describes nature of the emergency and the necessity for this regulatory change in order to protect public health, safety and welfare.

Substance

Briefly identify and explain the new substantive provisions, the substantive changes to existing sections, or both. A more detailed discussion is provided in the "Detail of Changes" section below.

The purpose of this regulatory action is to repeal Part VII of 9VAC5-140 in its entirety.

Issues

Identify the issues associated with the regulatory change, including: 1) the primary advantages and disadvantages to the public, such as individual private citizens or businesses, of implementing the new or amended provisions; 2) the primary advantages and disadvantages to the agency or the Commonwealth; and 3) other pertinent matters of interest to the regulated community, government officials, and the public. If there are no disadvantages to the public or the Commonwealth, include a specific statement to that effect.

The primary advantage associated with the regulatory change is to protect the health, safety and welfare of the public through the reduced cost of electricity for citizens and businesses. Any potential adverse impacts are speculative as of this writing; however, should adverse impacts become apparent, they can be addressed at the appropriate time and by the appropriate regulatory means.

Alternatives to Regulation

Describe any viable alternatives to the regulatory change that were considered, and the rationale used by the agency to select the least burdensome or intrusive alternative that meets the essential purpose of the regulatory change. Also, include discussion of less intrusive or less costly alternatives for small businesses, as defined in § 2.2-4007.1 of the Code of Virginia, of achieving the purpose of the regulatory change.

Alternatives to the proposal will be considered by the board. It has been tentatively determined that the first alternative is appropriate, as it is the least burdensome and least intrusive alternative that fully meets the purpose of the regulatory action. The alternatives being considered, along with the reasoning by which any of the alternatives have been rejected, are discussed below.

1. Repeal the regulation to satisfy the provisions of EO-9. This option is being selected because it meets the stated purpose of the regulatory action.

2. Make alternative regulatory changes to those required by EO-9. This option is not being selected because it would not meet the stated purpose of the regulatory action.

3. Take no action. This option is not being selected because it would not satisfy the provisions of EO-9.

Periodic Review and Small Business Impact Review Announcement

If you wish to use this regulatory action to conduct, and this Emergency/NOIRA to announce, a periodic review (pursuant to § 2.2-4017 of the Code of Virginia and Executive Order 14 (as amended, July 16, 2018)), and a small business impact review (§ 2.2-4007.1 of the Code of Virginia) of this regulation, keep the following text. Modify as necessary for your agency. Otherwise, delete the paragraph below and insert "This NOIRA is not being used to announce a periodic review or a small business impact review."

This NOIRA is not being used to announce a periodic review or a small business impact review.

Public Participation

Indicate how the public should contact the agency to submit comments on this regulation, and whether a public hearing will be held, by completing the text below. In addition, as required by § 2.2-4007.02 of the Code of Virginia describe any other means that will be used to identify and notify interested parties and seek their input, such as regulatory advisory panels or general notices.

The the board is seeking comments on this regulation, including but not limited to: ideas to be considered in the development of this regulation, the costs and benefits of the alternatives stated in this background document or other alternatives, and the potential impacts of the regulation. The the board is also seeking information on impacts on small businesses as defined in § 2.2-4007.1 of the Code of Virginia. Information may include: 1) projected reporting, recordkeeping, and other administrative costs; 2) the probable effect of the regulation on affected small businesses; and 3) the description of less intrusive or costly alternatives for achieving the purpose of the regulation.

Anyone wishing to submit written comments may do so by mail, email or fax to Karen G. Sabasteanski, Department of Environmental Quality, P.O. Box 1105, Richmond VA 23218, phone 804-659-1973, fax 804-698-4178, email karen.sabasteanski@deq.virginia.gov. Comments may also be submitted through the Public Forum feature of the Virginia Regulatory Town Hall (http://www.townhall.virginia.gov). Written comments must include the name and address of the commenter. In order to be considered, comments must be received before midnight on the last day of the public comment period.

Public Hearing at Proposed Stage

[If holding a public hearing after the proposed stage, insert:]
A public hearing will be held following the publication of the proposed stage of this regulatory action and notice of the hearing will be posted on the Virginia Regulatory Town Hall (http://www.townhall.virginia.gov) and on the Commonwealth Calendar (https://www.virginia.gov/connect/commonwealth-calendar).

[If not holding a public hearing during the proposed stage, insert:]
A public hearing will not be held following the publication of the proposed stage of this regulatory action unless requests for a public hearing are received during the NOIRA public comment period from at least 25 persons.

Regulatory Advisory Panel

Please indicate, to the extent known, if advisers (e.g., regulatory advisory panel or negotiated rulemaking panel) will be involved in the development of the proposed regulation. Indicate that 1) the agency is not using a panel in the development of the proposal; 2) the agency is using a panel in the development of the proposal; or 3) the agency is inviting comment on whether to use a panel to assist the agency in the development of a proposal.

The board does not intend to establish a panel to assist in the development of the proposal. However, in response to requests received during the NOIRA public comment period the board will consider establishing a panel. Persons requesting the agency use a panel and interested in assisting in the development of a proposal should notify the Department's contact person by the end of the comment period and provide their name, address, phone number, email address and their organization (if any). If a panel is used, notification of the composition of the panel will be sent to all applicants.

Detail of Changes

List all regulatory changes and the consequences of the changes. Explain the new requirements and what they mean rather than merely quoting the text of the regulation. For example, describe the intent of the language and the expected impact. Describe the difference between existing requirement(s) and/or agency practice(s) and what is being proposed in this regulatory change. Use all tables that apply, but delete inapplicable tables.

Current chapter-section number	New chapter-section number, if applicable	Current requirements in VAC	Change, intent, rationale, and likely impact of new requirements
9VAC5-140-6010		Purpose of the regulation is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6020		Terms defined.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6030		Measurements, abbreviations, and acronyms used in the regulation are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6040		Entities to which the regulation applies are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6050		Standard requirements for permitting, monitoring, recordkeeping, liability, etc., are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6060		Computation of time is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6070		Severability is established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6080		Authorization and responsibilities of the CO_2 authorized account representative are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6090		The role of the CO_2 authorized alternate account representative is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6100		Changing the CO_2 authorized account representatives and the CO_2 authorized alternate account representative; changes in the owners and operators are delineated.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6110		The elements of an account certificate of representation are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6120		Objections concerning the CO_2 authorized account representative are addressed.	Repealed in accordance with the directives of EO-9.

9VAC5-140-6130		Delegation by CO_2 authorized account representatives and CO_2 authorized alternate account representatives is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6140		CO_2 budget permit requirements are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6150		Submission of CO_2 budget permit applications.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6160		Information requirements for CO_2 budget permit applications are established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6170		Compliance certification reports are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6180		Actions on compliance certifications are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6190		The Virginia CO_2 Budget Trading Program base budgets are listed.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6200		How to handle undistributed and unsold CO_2 allowances is found in this section.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6210		Allowance allocations are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6220		CO_2 allowance tracking system accounts are established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6230		Establishment of accounts is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6240		The CO_2 allowance tracking system responsibilities of CO_2 authorized account representatives are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6250		How the recordation of allowance allocations is to be accomplished.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6260		Compliance requirements are established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6270		Banking requirements are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6280		Management of account errors is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6290		How to close general accounts.	Repealed in accordance with the directives of EO-9.

9VAC5-140-6300		How to submit CO_2 allowance transfers.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6310		The recordation of allowance transfers is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6320		Notification of allowance transfers is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6325		Life-of-the-unit contractual arrangements are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6330		General requirements for monitoring, reporting, and recordkeeping.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6340		The initial certification and recertification procedures for a monitoring system are delineated.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6350		Out-of-control periods are addressed.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6360		Notifications are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6370		Recordkeeping and reporting requirements are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6380		Petitions for approval to apply an alternative to any acid rain requirement are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6390		Reserved.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6400		Reserved.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6410		The purpose of the requirements for allowance auctions is provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6420		General requirements for the auction notice.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6430		[repealed section]	[already repealed]
9VAC5-140-6440		Program monitoring and review requirements.	Repealed in accordance with the directives of EO-9.

Family Impact

In accordance with § 2.2-606 of the Code of Virginia, assess the potential impact of the proposed regulatory action on the institution of the family and family stability including to what extent the regulatory action will: 1) strengthen or erode the authority and rights of parents in the education, nurturing, and supervision of their children; 2) encourage or discourage economic self-sufficiency, self-pride, and the assumption of responsibility for oneself, one's spouse, and one's children and/or elderly parents; 3) strengthen or erode the marital commitment; and 4) increase or decrease disposable family income.

A positive impact to the institution of the family may be anticipated as a result of improved health, safety and welfare of the public through the reduced cost of electricity for citizens.

REG\DEV\A22-E-01PD

ATTACHMENT H

#[date]

Andrew McKeon
Executive Director
The Regional Greenhouse Gas Initiative, Inc.
90 Church Street, 4th Floor
New York, NY 10007

Re: Notice of Intent to Withdraw the Commonwealth of Virginia from RGGI

Dear Mr. McKeon:

In accordance with Governor Youngkin's Executive Order 9 (2022), this letter is to notify the Regional Greenhouse Gas Initiative, Inc. (RGGI, Inc.) of the following actions to be undertaken by the Virginia Department of Environmental Quality:

1. Provide the Governor with a full report re-evaluating the costs and benefits of participation in RGGI in view of all available data, within 30 days.

2. During this same period, develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal the CO_2 Budget Trading Program (Part VII of 9VAC5-140).

3. During this same period, take all necessary steps so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the Code of Virginia.

4. During this same period, notify RGGI, Inc., of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

Accordingly, this letter notifies RGGI, Inc., of the Governor's intent to withdraw the Commonwealth of Virginia from RGGI upon the conclusion of an appropriate legislative or regulatory process. I will keep you informed as this process progresses. Please contact either me or my staff if you have any questions.

Sincerely,

MSR/MGD/kgs

Attachment 2

VIRGINIA:

IN THE CIRCUIT COURT FOR THE CITY OF RICHMOND
JOHN MARSHALL COURTS BUILDING

RECEIVED AND FILED
CIRCUIT COURT
MAY 07 2021
EDWARD F. JEWETT, CLERK
BY_____D.C.

VIRGINIA MANUFACTURERS ASSOCIATION,	:	
Petitioner,	:	
v.	:	Case No.: CL20-4918
VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY, ET AL.,	:	Hon. Judge Beverly W. Snukals
Respondents.	:	

Respondents' Brief in Opposition

Respondents, the Virginia Department of Environmental Quality ("DEQ"), the State Air Pollution Control Board, and Director David Paylor, the Director of DEQ, by counsel, respectfully submit this brief in Opposition to the Petitioner's appeal.

This case is important, but not complex. The General Assembly passed legislation mandating that DEQ amend regulations for the CO_2 Budget Trading Program. The legislation expressly exempted the amended regulations from the Virginia Administrative Process Act ("APA"). DEQ followed the General Assembly's mandate and promulgated amended regulations.

Petitioner, Virginia Manufacturers Association ("VMA") has appealed the amended regulations but not challenged the legislation that required them. As discussed below, VMA's arguments are incorrect: the amended regulations follow the General Assembly's mandate, indeed at times, incorporating *verbatim* the language from the legislation; the amended regulations are exempt from the APA; they are not vague; and there is no illegal tax on electricity ratepayers. VMA is asking this Court to set aside a program that controls CO_2 pollution and provides millions of dollars to help low-income households and vulnerable shoreline communities. This Court should not be persuaded to undermine these efforts in contravention of the law.

Table of Contents

Relevant Factual History....1

I. The Act mandated that DEQ establish a CO2 auction trading program and then sell 100% of Virginia's CO2 allowances through that program. 1

A. Before the Act, Virginia could only participate in CO_2 auctions on a limited, "consignment" basis....1

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C. The Act explicitly exempted the Amended Regulations from the APA.....3

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Relevant Factual History

The relevant facts in this case are not in dispute.[1] As discussed below, before 2020, DEQ had a CO_2 budget trading program that was limited to utilizing a conditional allowance / consignment model. In 2020, the General Assembly passed legislation that mandated DEQ to implement a CO_2 direct auction program and then to sell all CO_2 allowances through such auctions. The General Assembly further required that DEQ implement these changes by amending its existing regulations and then expressly exempted those amendments from the APA. It is those Amended Regulations that VMA challenges in this case.

I. The Act mandated that DEQ establish a CO_2 auction trading program and then sell 100% of Virginia's CO_2 allowances through that program.

A. Before the Act, Virginia could only participate in CO_2 auctions on a limited, "consignment" basis.

The State Air Pollution Control Board, with the support of DEQ, adopted regulations establishing a CO_2 Budget Trading Program on April 19, 2019 and published those regulations on May 27, 2019 (hereafter referred to as the "Original Regulations"). VMA Pet. at ¶ 35.[2]

[1] VMA filed over 450 pages of attachments to its Brief in Support; most of these documents were not included in the Certified Agency Record. VMA never objected to the Certified Agency Record nor moved to supplement the record. Thus, this Court need not consider any of these documents as they are not part of the record in this case. *See* Va. Sup. Ct. R. 2A:3(c) (2020). Moreover, most of these documents are irrelevant to the issue in this case, which is whether DEQ's Amended Regulations are *lawful.* VMA's attachments address whether it is a good *policy* to establish a CO_2 trading program. *See, e.g.*, VMA Attachment E (2017 article on RGGI); Attachment J (cost study of Virginia's CO_2 trading program). The General Assembly answered that policy question in 2020. Thus, these attachments are largely irrelevant to this case.

[2] The dates of adoption and publication for the Original Regulations are significant because, as discussed below, it is by those dates that the General Assembly refers to the Original Regulations in the Clean Energy and Community Flood Preparedness Act.

Prior to adoption, the Original Regulations went through a full notice and comment process pursuant to the APA. *Id.* at ¶ 33. VMA participated in that process and submitted "extensive written comments." *Id.*

The Original Regulations were limited because DEQ lacked legislative authority to either directly sell CO_2 allowances in an auction or spend or receive proceeds from an auction. *Id.* at ¶ 31. The Original Regulations worked around these limitations by utilizing a consignment model. Under the Original Regulations, DEQ granted "conditional allowances" to power plants and other CO_2 sources, those sources then "consigned" those allowances over to the CO_2 auction program where they were sold at a consignment auction. *Id.* At the same time, CO_2 sources were required to obtain CO_2 allowances that equaled their CO_2 emissions. *Id.* In this way, DEQ neither participated directly in the auctions nor spent or received revenue from the auction. *Id.*

B. The General Assembly mandated that DEQ establish a CO_2 direct auction and "sell 100 percent" of all annual CO_2 allowances in the auction.

In the 2020 legislative session, the General Assembly passed two historic pieces of environmental legislation. The first was the Virginia Clean Economy Act, which is not subject to this lawsuit. The second was the Virginia Clean Energy and Community Flood Preparedness Act (hereafter referred to as the "Act.").[3]

[3] Both the media and trade publications immediately recognized the significance of both pieces of legislation. As one commenter described the importance of the Act:

> The Act directs DEQ to revise the Rule without notice and comment through the Virginia Administrative Process Act by incorporating the statute into the existing Rule. Now, Virginia will be sprinting toward RGGI membership by the end of this year. Direct RGGI membership is a significant shift from the prior consignment membership….

Liz Williamson, *Virginia Regional Carbon Trading: Ready, Set, Join RGGI!*, JD Supra, July 15, 2020) (available at https://www.jdsupra.com/legalnews/virginia-regional-carbon-trading-ready-77904/ (last visited Apr. 14, 2021). *See also Virginia Enacts Aggressive Clean Energy Laws*, The National Law Review (Apr. 17, 2020) (available at

The Act created a new Virginia Code provision: Section 10.1-1330, which requires DEQ to take two actions. First, Section 1330.B. authorizes the Director of DEQ to "establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article." Va. Code § 10.1-1330.B (2020). Second, the section mandates that the "Director shall seek to sell 100 percent of all allowances issued each year through the allowance auction." *Id.*[4]

C. The Act explicitly exempted the Amended Regulations from the APA.

Subsection A of Section 1330 of the Act requires DEQ to incorporate the provisions of the Act "into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019." Va. Code § 10.1-1330.A. The dates referenced in this provision refer to the dates of adoption and publication of the Original Regulations; *i.e.*, the regulations that developed the conditional allowance / consignment model described above.

Section 1330.A. then states: "Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 *et seq.*)." *Id.*

Thus, Section 1330 is clear. Whereas before, DEQ was not allowed to directly participate in a CO_2 auction and could not directly receive proceeds from auction sales, now:

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https://www.natlawreview.com/article/virginia-enacts-aggressive-clean-energy-laws (last visited Apr. 14, 2021); *Virginia Gov. Ralph Northam signs clean energy legislation*, WJHL News (Apr. 12, 2020) (available at https://www.wjhl.com/news/regional/virginia/virginia-gov-ralph-northam-signs-clean-energy-legislation/ (last visited Apr. 14, 2021).

[4] The legislation also contains several provisions that are not directly relevant to this case, but which demonstrate the General Assembly's purpose and intent. For example, the General Assembly revised Virginia Code 10.1-603.25 by converting the Virginia Shoreline Resiliency Fund into the Virginia Community Flood Preparedness Fund. Pursuant to the revisions, the fund "shall be used solely for the purpose of enhancing flood prevention or protection and coastal resilience as required by this article." Va. Code § 10.1-603.25.B. The General Assembly also required that "[n]o less than 25 percent of the moneys disbursed from the Fund each year shall be used for projects in low-income geographic areas." Va. Code § 10.1-603.25.E.

- DEQ must implement and manage a CO_2 auction program;
- DEQ must sell 100% of all CO_2 allowances through an allowance auction; and
- DEQ must do these tasks by amending the Original Regulations; however, those amendments are exempt from the APA.

II. DEQ followed the Act's mandate by revising its CO_2 Trading Regulations so that Virginia could directly participate in CO_2 auctions.

Consistent with the Act, on July 10, 2020, DEQ issued amendments to the Original Regulations (hereafter referred to as the "Amended Regulations"). VMA Pet. at ¶ 43. These Amended Regulations comprise the majority of the Certified Agency Record that DEQ filed in this case. Specifically, the Amended Regulations begin on the third page of the Certified Agency Record and consist of 57 pages of regulations that are now codified as 9 VAC5-140-6010 through 9 VAC5-140-6440. The Amended Regulations, as filed as part of the Certified Agency Record in this case, are paginated 1 through 57, with the page number appearing on the top right corner of each page. For ease of reference, this Opposition Brief will refer to this pagination system when citing to the Amended Regulations.

The Amended Regulations, as filed in this case, show both the Original Regulations and the amendments. The Original Regulations appear as regular typeface. Where DEQ deleted words, those words appear with a line through them. Where DEQ added words, those words are underlined. *See, e.g.*, Amended Regulations at 2 ("Allocate" or "allocation" means the determination by the department of the number of ~~conditional~~ $\underline{CO_2}$ allowances recorded in the ~~conditional~~ allowance account of a CO_2 budget unit…"). In other words, the Amended Regulations DEQ has filed with this Court are a blackline, edited version of the Original Regulations that show both the Original Regulations and the Amended Regulations.

As the Amended Regulations demonstrate, most of the Original Regulations remain unchanged. For example, two of the regulations that VMA challenge as impermissibly vague, 9 VAC5-140-6050.C and 9 VAC5-140-6260 (*see* VMA Brief at 22), are unchanged and only contain minor edits that update dates and remove obsolete terminology. *See* Amended Regulations at 16 (showing the only amendments to 9 VAC5-140-6050.C are to remove the phrase "initial control period" and to update dates); at 39 – 43 (showing minimal changes to 9 VAC5-140-6260).

Most of the changes in the Amended Regulations, as required by the Act, change the CO_2 trading program from a conditional allowance / consignment model to a direct auction model. For example, the Amended Regulations add language stating that CO_2 allowances would now be sold "by the Department or its agent" through an auction. *Id.* at 5. The Amended Regulation also delete references to conditional allowances and consignment auctions. *Id.* at 6-7; 28; 32-33; 56-57.[5]

III. Virginia received $43 million in net revenue from its first auction.

On March 5, 2021, Virginia participated in its first quarterly auction of CO_2 allowances. As reported, Virginia earned more than $43 million in net proceeds from the auction.[6] Pursuant to the Act, 45% of this revenue will assist localities affected by flooding and sea level rise. Va. Code § 10.1-1330.C. 50% of this revenue will be spent on low-income energy efficiency programs. *Id.* The next RGGI auction is scheduled for June 2, 2021.[7]

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[5] The Amended Regulations also add to the definition of the term "life-of-the-unit contractual arrangement" and then have a new regulation specifying the parties' obligations for CO_2 allowances under such an arrangement. *Id.* at 9-10; 45. These new regulations were explicitly required by Section 1331 of the Act. *See* Va. Code § 10.1-1331.

[6] *See* Sarah Vogelsong, *Virginia Nets More than $43 Million in First Carbon Allowance Auction*, The Virginia Mercury (Mar. 9, 2021) (available at https://www.virginiamercury.com/blog-va/virginia-nets-more-than-43-million-in-first-carbon-allowance-auction/) (last visited Apr. 13, 2021).

[7] https://www.rggi.org/auctions/upcoming-auctions.

Standard of Review and Burden of Proof

I. Standard of review when comparing regulations to enabling legislation.

At its core, VMA's Brief argues that the Amended Regulations are inconsistent with the Act. As the Virginia Court of Appeals has explained: "[w]hen [a] [c]ourt reviews whether a regulation is inconsistent with its enabling legislation, it must take into account the text as well as the context in the underlying statute, viewing it as a symmetrical and coherent regulatory scheme." *Karr v. Dep't of Envtl. Quality*, 66 Va. App. 507, 526 (2016) (internal citations and quotation marks omitted). Further, a court "is duty bound to interpret the several parts of a statute as a consistent and harmonious whole so as to effectuate the legislative goal." *Id.* at 527 (citing *Virginia Elec. & Power Co. v. Citizens for Safe Power*, 222 Va. 866, 869 (1981)).

Finally, although "pure questions of statutory interpretation" are subject to *de novo* review, if the statute in question "falls within the agency's specialized competence, the agency decision is entitled to special weight and will be overturned only if it constitutes a clear abuse of the delegated discretion." *Dorman v. Commonwealth*, 2019 Va. App. LEXIS 209, *6 (2019) (unpublished) (internal citations omitted); *see also Thormac, LLC v. Dep't of Alcoholic Bev. Control*, 68 Va. App. 216, 223 (Va. Ct. App. 2017) ("where the question involves an interpretation which is within the specialized competence of the agency and the agency has been entrusted with wide discretion by the General Assembly, the agency's decision is entitled to special weight in the court.").

II. Burden of proof

The APA places the burden upon VMA to demonstrate an error of law. Va. Code § 2.2-4027. "[T]he agency action is presumed valid on review and the burden rests upon the party complaining to overcome this presumption." *Strawbridge v. Cnty. of Chesterfield*, 23 Va. App. 493, 503 (1996).

Argument

VMA's Brief asserts four arguments for why the Amended Regulations should be declared void. These four arguments relate to VMA's six assignments of error that it has listed in its Petition for Appeal. For ease of reference, this Opposition Brief will address each of VMA's arguments in the order they were presented.

I. The Amended Regulations satisfy the Act's mandate of implementing a "market-based trading program consistent with the RGGI program" and of selling "100 percent of all allowances each year through the allowance auction."

VMA's first argument is that DEQ violated the Act when it issued the Amended Regulations. VMA Brief at 17. As discussed below, this argument fails because DEQ satisfied the Act's mandate that it establish a CO_2 auction program and then sell all CO_2 allowances through those auctions. Furthermore, VMA's assertion that DEQ "failed to incorporate" certain portions of the Act fails because those portions of the Act either had no relevance to the CO_2 auction program or were implemented in the Amended Regulations *verbatim*.

A. DEQ's Amended Regulations follow the General Assembly's Mandate.

Section 1330.B of the Act (codified at Virginia Code Section 10.1-1330.B) contains two sentences, each of which directs DEQ to take certain action. First, the Act authorizes DEQ to "establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article." Va. Code § 10.1330.B. Second, the Director of DEQ "shall seek to sell 100 percent of all allowances issued each year through the allowance auction." *Id.*

DEQ did exactly as the General Assembly instructed. Through the Amended Regulations, DEQ struck all language referencing the former consignment model and replaced it with the direct auction model the Act requires. For example, the Amended Regulations:

- Added language stating that CO_2 allowances would now be sold "by the Department or its agent" through a direct auction (Amended Regulations at 5);
- Deleted reference to conditional allowances and consignment auctions (*id.* at 6 – 7);
- Deleted "conditional allowances" and replaced them with "CO_2 allowances" (*id.* at 28);
- Repealed the methodology for conditional allocations (*id.* at 32 – 33); and
- Repealed the consignment auctions (*id.* at 56 – 57).

VMA does not, and cannot, dispute that the Amended Regulations repealed consignment auctions, removed references to conditional allowances, and removed other transitional provisions that are not compatible with a direct auction program. *See* VMA Brief at 17 (alleging that the Amended Regulations "*implement*" the Act but still violate it) (emphasis in original). Simply put, the Act mandated that DEQ take two significant steps: implement and manage a direct auction CO_2 program, and sell 100% of Virginia's CO_2 allowances in that program. Through the Amended Regulations, DEQ has done exactly what the General Assembly mandated. DEQ did not violate the Act, it followed it.

B. VMA's argument that DEQ "failed to incorporate" certain provisions of the Act fails because those provisions are either unrelated to DEQ's mandate or explicitly incorporated in the Amended Regulations.

Rather than argue that the Amended Regulations fail to satisfy the Act's mandate, VMA argues that DEQ did not go far enough and that, allegedly, DEQ "failed to incorporate" certain provisions of the Act. VMA Brief at 17. As discussed below, VMA is incorrect.

1. VMA's allegation that DEQ failed to incorporate the definitions section of the Act is both illogical, because that section did not require DEQ to do anything, and undermined by the 13 pages of definitions in the Amended Regulations.

First, VMA alleges that DEQ "failed to incorporate" Section 10.1-1329 of the Act. VMA Brief at 17. Section 1329 is titled "Definitions" and is a list of nine defined terms that are used in

the Act, including "DMME," "Energy efficiency program, and "Fund." Va. Code § 10.1-1329. ("As used in this article, unless the context requires a different meaning: [followed by nine defined terms]").

VMA's argument seems to be that DEQ was required to define terms such as "DMME" or "Fund" in the Amended Regulations. There are two problems with this argument. First, definitions prescribed by the General Assembly are already incorporated into the Board's regulations. The very first section in the Board's Regulations, 9 VAC5-10-10, provides that "[u]nless specifically defined in the Virginia Air Pollution Control Law . . . terms used [in the Air Board's regulations] shall have the meanings given them by 9VAC5-170-20, or commonly ascribed to them by recognized authorities." 9 VAC5-10-10(B). Thus, the regulations, by operation of 9 VAC5-10-10(B), defer to and adopt definitions provided by the General Assembly. *Id.* DEQ has already incorporated the definitions contained in the Act by virtue of existing regulations. Repeating this incorporation in the Amended Regulations would be redundant.

Second, the fact that the General Assembly included a list of defined terms in the Act does not require DEQ to do anything in its Amended Regulations. Indeed, those Amended Regulations contain 13 pages of definitions, many of which were unchanged by the amendments. *See* Amended Regulations at 1-13. DEQ did not "fail to incorporate" Section 10.1-1329 because there was nothing in that section for DEQ to incorporate. And, VMA has not shown a single instance where the definitions in the Amended Regulations contradict or undermine the Act's defined terms. Thus, VMA is incorrect: DEQ did not violate the Act by "failing to incorporate" the definitions listed in the Act. The Board's existing regulations already incorporate by reference definitions passed by the General Assembly, the Original Regulations already had a lengthy definitions section, and DEQ amended those definitions where necessary to comply with the Act. *Id.*

2. VMA's allegation that DEQ failed to incorporate Section 1331 is incorrect: The Amended Regulations contain a nearly *verbatim* inclusion of that section.

Second, VMA alleges that DEQ "failed to incorporate" Section 10.1-1331. *See* VMA Brief at 17 (listing Section 10.1-1331 as one of the provisions DEQ "failed to incorporate") and at 18 (alleging that the Amended Regulations "also has not incorporated . . . Section 1331.").

This argument is demonstrably false: not only do the Amended Regulations incorporate this section, they do so nearly *verbatim*. Section 1331 of the Act (codified at Virginia Code Section 10.1-1331) is titled "Energy conversion or energy tolling agreements." The section states that if Virginia becomes a "full participant in RGGI," then two items must be included in DEQ's Amended Regulations. Va. Code § 10.1-1331. First, the Amended Regulations must include within its definition of the phrase "life-of-the-unit contractual arrangement" the following phrase: "any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO2 budget source or CO2 budget unit and is entitled to receive all of the nameplate capacity" from that source. *Id.* Second, the Act requires the Amended Regulations include a provision stating that under such an agreement, the purchaser is responsible for acquiring the associated CO_2 allowances. *Id.*[8]

The Amended Regulations include both requirements. The Original Regulations already contained a definition of "life-of-the-unit contractual arrangement." *See* Amended Regulations at 9-10 (showing the original definition in subsection "a"). Thus, the Amended Regulations added

[8] A "life-of-the-unit contractual arrangement" in the electricity utility industry is essentially a dedicated power plant: a situation where a power plant commits, by long-term contract, to provide all or most of its produced electricity to a single purchaser. *See, e.g.* 42 U.S.C. § 7651a(27) (2020) (defining the term under federal law). Section 1331 of the Act clarifies that under such a contractual arrangement, it is the power purchaser who must obtain the CO_2 allowances. *See* Va. Code § 10.1-1331 ("any purchaser under an energy conversion or energy tolling agreement shall be responsible for acquiring any CO2 allowances"); Amended Regulations at 45 (adding a new section, 9 VAC5-140-6325, that includes this same clarification).

the word "either" to the definition, made the original definition subsection "a." and then added a new "b." *Id.* Subsection b of that definition is, *verbatim*, the definition from Section 1331. *Id.*

Then, the Amended Regulations added a new provision, 9 VAC 5-140-6325, that clarifies that the purchaser under such an arrangement is responsible for obtaining the necessary CO_2 allowances. *Id.* at 45.

So that there is no doubt as to whether the Amended Regulations incorporate Section 1331, here is the exact language from both the Act and the Amended Regulations:

Section 1331 of the Act	**Relevant Amended Regulations**
If the Governor seeks to include the Commonwealth as a full participant in RGGI or another carbon trading program… then	
(i) the definition of the term "life-of-the-unit contractual arrangement" under the Final Regulation shall include any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO2 budget source or CO2 budget unit and is entitled to receive all of the nameplate capacity and associated energy generated by such source or unit for the entire contractual period and	"Life-of-the-unit contractual arrangement" means either… (b) For any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO_2 budget source or CO_2 budget unit and is entitled to receive all of the nameplate capacity and associated energy generated by such source or unit for the entire contractual period. (Amended Regulations at pp. 9-10.)
(ii) any purchaser under an energy conversion or energy tolling agreement shall be responsible for acquiring any CO2 allowances required under the Final Regulation in relation to a CO2 budget source or CO2 budget agreement that is subject to such agreement.	A power purchaser entered into a life-of-the-unit contractual arrangement… shall be responsible for acquiring and transferring all allowances to the CO_2 budget source or unit that are necessary for demonstrating compliance with the CO_2 budget trading program. (Amended Regulations at p. 45.)

VMA never mentions the Amended Regulations' new definition of "life-of-the-unit contractual arrangement." VMA Brief at 17-18. Nor does VMA ever mention the new

requirement, codified in 9 VAC5-140-6325, that the purchaser under such an arrangement acquire the requisite CO_2 allowances. *Id.* Instead, VMA ignores these provisions and claims that the Amended Regulations "fail to incorporate" Section 1331. *Id.* This is simply false: the Amended Regulations incorporate, on a nearly *verbatim* basis, Section 1331.[9]

3. VMA's allegation that the Amended Regulations "fail to incorporate" Section 10.1-1330(C) is a red herring: that provision addresses how the *proceeds* from direct auctions will be spent; there is nothing in that provision for DEQ to include in its regulations implementing and managing a direct auction program.

Third, VMA alleges in its Petition for Appeal that DEQ failed to incorporate Section 10.1-1330.C, which VMA describes as "the most substantive and impactful part" of the Act. VMA Pet. at ¶ 51. Curiously, VMA never makes this argument in its Brief in Support. *See* VMA Brief at 17-18 (listing the three provisions of the Act it alleges that DEQ "failed to incorporate" but not including Section 10.1-1330.C). Nonetheless, because VMA made this assertion in its Petition for Appeal, the Respondents will address it here.

Section 1330.C of the Act (codified at Virginia Code Section 10.1-1330.C) specifically provides for how the proceeds from the CO_2 direct auctions shall be allocated:

1. 45% of the revenue shall go to the Virginia Community Flood Preparedness Fund;

[9] In support of its argument that DEQ failed to incorporate Section 1331, VMA cites *Jackson v. Marshall*, 454 S.E.2d 23 (Va. Ct. App. 1995). VMA Brief at 18. VMA cites *Jackson* for the proposition that "no deference can be given to an agency when compliance with a statute is at issue." *Id.* The word "deference" is only used once in in the *Jackson* opinion: "On review, the interpretation which an administrative agency gives its law must be accorded great deference." *Jackson*, 454 S.E.2d at 26. Not only is VMA's characterization of *Jackson* incorrect, it is also irrelevant. *Jackson* involved a Department of Social Services administrative hearing over allegations of sexual abuse where the hearing officer issued a ruling finding "Reason to Suspect Sexual Abuse," yet the statute at issue only allowed for findings of either "Founded" or "Unfounded." *Id.* at 24-25. The *Jackson* court then reasoned that, even though agency interpretation of its law "must be accorded great deference," where a statute "is clear and unambiguous, a court will give the statute its plain meaning." *Id.* at 26. Here, Section 1331 is clear and DEQ inserted its provisions directly into the Amended Regulations. Thus, *Jackson* is inapplicable.

2. 50% of the revenue shall go to the Department of Housing and Community Development to support low-income energy efficiency programs;
3. 3% of the revenue shall go to DEQ to cover administrative expenses of managing the auction and related activities; and
4. 2% of the revenue shall go to the Department of Housing and Community Development, in partnership with the Department of Mines, Minerals, and Energy, to administer and implement the low-income efficiency programs funded above.

Va. Code § 10.1-1330.C.

There is nothing in this provision related to how DEQ shall "establish, implement, and manage" the CO_2 direct auction program. Va. Code § 10.1-1330.B. Nor is there anything in this provision related to how the Director of DEQ shall "seek to sell 100 percent of all allowances issued each year." *Id.* Thus, there was nothing for DEQ to incorporate from Section 1330.C into the Amended Regulations. Indeed, it would be nonsensical for DEQ, through regulations that implement the auction program, to prescribe rules for how other state agencies, such as the Department of Housing and Community Development, are to administer separate programs. DEQ did not "fail to incorporate" Section 1330.C as VMA alleges; rather, there is nothing in that provision for DEQ to incorporate in the Amended Regulations.[10]

[10] VMA included a fourth "failure to incorporate" allegation in its brief. In two separate places, VMA alleges that DEQ failed to incorporate "Section 10.1-1300." *See* VMA Brief at 17 (listing among the sections DEQ allegedly "failed to incorporate" "Section 10.1-1300"); at 18 ("Revision A20 also has not incorporated Section 10.1-1300 . . . ."). This could be a typographical error as Virginia Code Section 10.1-1300 is not part of the Act, is unrelated to the CO_2 trading program, and is not mentioned in VMA's Petition for Appeal.

Since VMA makes this assertion twice in its brief; however, the Respondents will briefly address it here. This allegation should be rejected for three reasons. First, VMA did not identify this provision as an assignment of error in its Petition for Appeal; and therefore, has waived its right to raise this new issue now. *See* Va. Sup. Ct. R. 2A:4(a) (requiring a petition for appeal to "specify the errors assigned") (2020). Second, this code provision was not changed by the Act.

II. VMA's APA-based assignments of error fail because: (A) the Act exempted the Amended Regulations from the APA; and (B) the Act authorized each of the changes VMA identifies in its brief.

VMA's first three assignments of error (Claims I, II, and III) in its Petition for Appeal allege that DEQ violated the APA by issuing the Amended Regulations without going through APA's notice-and-comment process. VMA Pet. at ¶¶ 58-78. VMA supports these claims through the second argument in its brief. *See* VMA Brief at 18-21. As discussed below, VMA's argument is incorrect because the Act expressly exempts the Amended Regulations from the APA and because the Act authorizes each of the changes VMA complains of.

A. The Act expressly exempts the Amended Regulations from the APA.

Section 1330.A of the Act (codified at Virginia Code Section 10.1-1330.A) states:

> The provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department *shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et. seq.*).

Va. Code § 10.1-1330.A (emphasis added). Thus, the Act expressly exempts DEQ's Amended Regulations from the requirements of the APA. This Court's analysis need go no further.

VMA incorrectly alleges that DEQ claims that the Amended Regulations qualify for one of the exemptions listed in the APA. VMA Brief at 19 (asserting that DEQ was invoking Virginia Code 2.2-4006(A)(4)(a) to justify avoiding the APA). In support of this assertion, VMA cites "Attachment A (Agency Record) at 3." *Id.* But nowhere on that page, nor anywhere else in the

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Virginia Code Section 10.1-1300 is the definitions section for the chapter of the Virginia Code that establishes the State Air Pollution Control Board. It was last amended in 2015, well before the Original Regulations or the Act. *See* Va. Code § 10.1-1300 (legislative history section showing the last amendment in 2015). Thus, VMA's argument that DEQ somehow violated "the Act" by failing to incorporate this section is internally inconsistent: this section is not part of the Act so failing to incorporate it cannot be a violation of the Act. Finally, VMA has not identified any definition or provision in the Amended Regulations that is inconsistent with Section 10.1-1300. Thus, VMA's contention that DEQ "failed to incorporate" this code provision is without merit.

record, does DEQ ever claim this APA exemption. There is no reason to claim such an exemption: the Act exempts the Amended Regulations from the APA. [11]

VMA relies upon a strawman fallacy: after misrepresenting DEQ's justification for not going through the APA process, VMA spends the remainder of its second argument refuting DEQ's supposed position. *See* VMA Brief at 19-22. There was no reason for DEQ to resort to one of the APA's exemptions when the Act exempted the Amended Regulations from the APA.[12]

B. The Act authorized each of the changes VMA identifies in its brief.

VMA concedes that the Act exempts the Amended Regulations from the APA. VMA Brief at 19. But according to VMA, DEQ went "far beyond the scope of the exemption" and included

[11] Recently, VMA made the same APA argument in a case before the Honorable Judge W. Reilly Marchant. In *VMA v. Northam*, Case No. CL20-4521, VMA asserted that emergency temporary standards for workplace safety, passed in response to the COVID-19 pandemic, were illegal because they did not go through the APA process. VMA also asserted that Governor Northam's emergency executive orders, also passed in response to the COVID-19 pandemic, had to go through the APA process. This Court dismissed VMA's APA claim reasoning:

> Count I is an allegation that there are violations to the Administrative Process Act. The Court finds that the VAPA doesn't apply to executive orders. In regard to the Emergency Temporary Standards, the Court also agrees with the Defense that 40.1 exempts the ETS, the Emergency Temporary Standards, from the VAPA. They exempt it. So the Court grants the Defense motion to dismiss Count I for those reasons.

VMA v. Northam, Case No. CL20-4521, Hearing Transcript at 60:6-15 (Feb. 16, 2021). *See also* Order Granting Motion to Dismiss at ¶ 1 ("Count I… is **HEREBY DISMISSED** for the reasons stated on the record at the February 16, 2021 hearing and because the VAPA does not apply to Emergency Executive Orders and because Virginia Code Section 40.1-22(6a) expressly exempts the Emergency Temporary Standard from the VAPA."). VMA has now filed a notice of appeal. *See* Notice of Appeal (Mar. 31, 2021).

While VMA may prefer to have the Amended Regulations go through the APA, just like they wanted the Emergency Temporary Standards at issue before the Honorable Judge Marchant to go through the APA, in both instances the General Assembly expressly exempted the regulations from the APA. In both instances, VMA's reliance on the APA is mistaken.

[12] VMA also asserts, without explanation, that the Act's APA exemption "is very narrow." VMA Brief at 20. Yet VMA does not point to any limiting language in the exemption.

"abundant substantive changes" in the Amended Regulations. *Id.* VMA then lists, in bullet-point format, six such changes.

Yet each of these changes are amendments that move Virginia from the previous consignment model (where DEQ granted "conditional allowances" to the regulated community who then consigned them over to the RGGI market) to the current direct auction model that the Act requires. Specifically, the first and third of VMA's examples are provisions where DEQ removed the concept of conditional allowances. *Compare* VMA Brief at 20 *with* Amended Regulations at 2 (replacing "conditional allowances" with "CO_2 allowances"). Similarly, the fourth, fifth, and sixth examples are provisions where DEQ removed the concept of a consignment auction and replaced it with a direct auction. *Compare* VMA Brief at 20 *with* Amended Regulations at 32-33 (repealing conditional allocation methodology regulations and removing reference to consignment auctions); at 56-57 (repealing consignment auction regulations).

These changes are expressly required by Section 1330.B of the Act, which requires DEQ to "establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program," and which requires the Director to "sell 100 percent of all allowances issued each year." Va. Code § 10.1-1330.B. Put differently, because the General Assembly mandated that DEQ move from the consignment/conditional allowance model to a direct auction model, DEQ amended its regulations to remove all references to consignment auctions and conditional allowances.

VMA characterizes its second example as an amendment that "strikes language in the definition for 'adjustment for banked allowances.'" VMA Brief at 20. This change, found on page 1 of the Amended Regulations, simply deletes the last phrase from the definition of the term "Adjustment for banked allowances." Specifically:

> "Adjustment for banked allowances" means an adjustment applied to the Virginia CO_2 Budget Trading Program base budget for allocation years 2021 through 2025 to address allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states~~, that are in addition to the aggregate quantity of emissions from all CO_2 budget sources in all of the participating states at the end of the initial control period in 2020 and as reflected in the CO_2 Allowance Tracking System on March 15, 2021~~.

Amended Regulations at 1. DEQ made this change because, by moving from the consignment model to being a "full participant in RGGI" (Act at Section 1331), DEQ was now in sync with RGGI's time schedule—not its own—and it no longer needed an "initial control period in 2020." *See* Amended Regulations at 9 (deleting the term "Initial Control Period.") In other words, the Original Regulations included both an "Initial Control Period" and an "Interim Control Period." *Id.* (including both terms in the Original Regulations). After the Act, DEQ no longer needed both concepts so it deleted the term "Initial Control Period" from the Amended Regulations. *Id.* For consistency, it then deleted the last phrase in the definition of "adjustment for banked allowances" that referenced this now obsolete term. *Id.* at 1. VMA incorrectly characterizes this change as more than it is by describing it as changing "how the adjustment shall be aggregated with other participating states." VMA Brief at 20. This is incorrect. The only revision, as shown on the record, is removing reference to an obsolete term, *i.e.*, allowances from the "Initial Control Period."[13]

[13] After listing six examples of "abundant substantive changes" that VMA contends are illegal, VMA includes another example. VMA claims that "DEQ opted to further exceed its authority" by imposing a new provision requiring manufacturing facilities that generate some of their own electricity to apply for a permit exemption. VMA Brief at 20. According to VMA, this requirement is not in the Act; and is therefore, not exempt from the APA. *Id.* This is another red herring. The manufacturing facility exemption already existed in the Original Regulations; thus, it already went through the APA process. *See* Amended Regulations at 14 (showing the Original Regulations and showing that the exemption found in 9 VAC5-140-6040 is not one of the new amendments). Thus, this exemption already went through the APA process and VMA's opportunity to appeal these regulations has passed.

III. Contrary to VMA's assertion, the Amended Regulations are not vague.

The third argument in VMA's Brief (and its sixth assignment of error in its Petition for Appeal) is that the Amended Regulations are "void as a vague regulation." VMA Brief at 21. As discussed below, VMA's argument is incorrect. First, to establish that a regulation is unlawfully void, VMA faces an incredibly high burden, yet VMA points to no language in the Amended Regulations that comes anywhere close to meeting that burden Second, each of the specific arguments VMA advances in support of its vagueness theory is flawed.

A. The Amended Regulations are not void under Virginia law.

VMA cites two Virginia Supreme Court cases in support of its unlawfully void argument: *Tanner v. City of Va. Beach*, 277 Va. 432 (2009), and *Volkswagon of Am., Inc. v. Smit*, 279 Va. 327 (2010). *See* VMA Brief at 22. In each opinion, the court begins its analysis by stating that setting aside a statute or regulation on voidness grounds, which is rooted in due process concerns, is an extreme remedy that should be avoided if possible. In *Tanner*, the court stated:

> We are required to resolve any reasonable doubt concerning the constitutionality of a law in favor of its validity. Thus, if a statute or ordinance can be construed reasonably in a manner that will render its terms definite and sufficient, *such an interpretation is required*.

Moreover, these facilities were already required to apply for a permit. *See generally* 9 VAC5 Chapter 85 (permits for stationary sources of pollutants subject to regulation). Thus, the permit requirement is not new either. The only new revision DEQ made to this exemption is to provide a new application deadline of January 1, 2022. *See* Amended Regulations at 14. There are other updated deadlines throughout the Amended Regulations. *See, e.g. id.* at 5 (updating calendar year trigger price definitions); at 10 (similar update for the definition of "minimum reserve price"); at 25 (new deadline for submission of CO_2 budget permit applications); at 27 (revising Virginia's base budget to begin in 2021 rather than 2020); at 46 (replacing certain 2020 deadlines with new 2021 deadlines). According to VMA's argument, anytime the General Assembly mandates that a state agency make changes to an existing regulatory regime, the General Assembly must also explicitly empower the agency to make necessary deadline changes that go with those revisions.

Tanner, 277 Va. at 438-39 (emphasis added) (citations omitted). In *Volkswagon*, the court began its analysis by citing *Tanner*, and adding, "a court should not declare a statute to be wholly unconstitutional unless such a determination *is absolutely necessary* to decide the merits of the case. *Volkswagon*, 279 Va. at 337 (emphasis added) (citations and internal quotations omitted).

Thus, VMA as the moving party, has the burden to demonstrate that there is no "reasonable doubt" that the Amended Regulations are so vague that they are incapable of being "construed reasonably in a manner that will render [them] definite and sufficient." *Tanner*, 277 Va. at 439.

VMA cannot meet this burden. The key obligation that the Amended Regulations place on owners and operators of fossil-fuel burning power plants is to acquire CO_2 allowances that are equal or greater than the amount of the plant's CO_2 emissions. This obligation is codified in 9 VAC5-140-6050.C. *See* Amended Regulations at 16. That provision states:

> 1. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source *shall hold CO_2 allowances* available for compliance deductions under 9 VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account *in an amount not less than the total CO_2 emissions* that have been generated as a result of combusting fossil fuel for an interim control period or control period from all CO_2 budget units at the source….

Id. There is nothing vague about this obligation. Indeed, each of the key terms in this regulation is specifically defined in the Amended Regulations. *See, e.g.*, Amended Regulations at 4 (defining "CO_2 budget source" and "CO_2 budget unit"); at 6 (defining "compliance account"); at 12 (defining "source" and "unit"). VMA fails to explain how any of this is vague; much less, incapable of being "construed reasonably in a manner that will render its terms definite and sufficient," which is the legal standard articulated in *Tanner*. 277 Va. at 438-39.

The Amended Regulations stand in stark contrast to the ordinance at issue in *Tanner*. There, Virginia Beach imposed a city ordinance that made it unlawful "for any person to create, or allow to be created any unreasonably loud, disturbing and unnecessary noise in the city." *Id.* at

435. The ordinance failed to define "unreasonably loud" and the trial court heard testimony from police officers that they interpreted the ordinance using a "reasonable person standard" that "depends on an individual officer's assessment." *Id.* at 437. The Virginia Supreme Court ruled that the ordinance was unlawfully vague because persons subject to the ordinance could not determine in advance whether activity was unlawful. *Id.* at 439-40.

Here, there is no reasonable person test. Indeed, the phrase "reasonable person" does not appear anywhere in the Amended Regulations. VMA fails to demonstrate how any CO_2 unit or budget source, subject to these Amended Regulations, is unable to determine whether activity is unlawful. The Amended Regulations are clear: such a regulated entity must acquire CO_2 allowances that are "not less than" its CO_2 emissions.[14]

There is one final point worth noting about VMA's vagueness claim. Challenges to statutes or regulations on vagueness grounds are due process claims. *See Volkswagon*, 279 Va. at 337. Yet most of the obligations the Amended Regulations place on power plants, such as the obligation to acquire CO_2 allowances, are not new: they are obligations that existed in the Original Regulations. *See, e.g.*, Amended Regulations at 16 (showing only one minor change to 9VAC-140-6050.C). The Original Regulations went through a full APA notice and comment process that VMA participated in. VMA elected not to appeal the Original Regulations. Thus, even if the obligations were somehow vague, VMA has had due process and waived its right to now challenge the specificity of these obligations.

B. Each of VMA's voidness arguments is flawed.

In support of its "unlawfully void" argument, VMA makes three arguments; each is flawed.

[14] Also, *Tanner* involved a city ordinance that applied to the general population. The Amended Regulations, by contrast, apply to fossil-fuel burning electric utilities and other large, sophisticated entities who already comply with a myriad of federal, state, and local regulations.

1. VMA's argument that the Amended Regulations "do not even mention" RGGI ignores the Act's mandate and how the Amended Regulations work.

First, VMA argues that "[w]ithout RGGI, the [Amended Regulations] cannot operate; however, the RGGI program is not even mentioned." VMA Brief at 22. There are two flaws in this argument. First, the Act does not require DEQ to join RGGI or mention RGGI in its amendments; rather, it very specifically mandates that DEQ "establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program." Va. Code § 10.1-1330.B. In other words, the General Assembly gave DEQ flexibility: it could join RGGI, create its own auction "consistent with the RGGI program," or should a new auction be created in the future, join it. *See also* Va. Code § 10.1-1331 ("If the Governor seeks to include the Commonwealth as a full participant in RGGI…."). DEQ followed the Act's mandate by fashioning Amended Regulations that are "consistent with RGGI" but would also be consistent with one of these other options. Thus, rather than being an unlawful ambiguity, the lack of the word "RGGI" in the Amended Regulations is intentional and consistent with the Act.

The second flaw with this argument is that other states' regulations do not mention RGGI either; yet there is no evidence that their auctions, which have been occurring for years, impose vague or uncertain obligations on participants.[15] If VMA's argument that regulations that fail to mention RGGI are so vague that they cannot be complied with, then one would not expect over a

[15] For example, Massachusetts' CO2 Budget Trading Program regulations are nearly identical to Virginia's Amended Regulations, yet Massachusetts has been successfully participating in RGGI auctions for years. *See* 310 Code of Mass. Regulations 7.70 (creating the "Massachusetts CO2 Budget Trading Program," requiring utilities to purchase allowances through that trading program, and only using the word "RGGI" when discussing the "RGGI CO_2 Allowance Tracking System"). *See also* 26 Code of Maryland Regulations Subtitle 9 (establishing the "Maryland CO2 Budget Trading Program" without using the word "RGGI"); 6 New York Code of Rules and Regulations Subpart 242-1 (establishing the New York CO2 Budget Trading Program but not using the word "RGGI"); Code of Vermont Regulations 12-031-002 (establishing the Vermont CO 2 Budget Trading Program but not using the word "RGGI").

decade of successful auctions by other states that have regulations that do not mention RGGI. *See, e.g.,* RGGI Auction Results (showing cumulative auction proceeds since RGGI's inception of $3,953,834,280.29) (available at https://www.rggi.org/auctions/auction-results) (last visited Apr. 14, 2021); RGGI Fourth Compliance Report (Apr. 2, 2021) (finding that "99.1% of covered power section emissions were in compliance" with auction requirements) (available at https://www.rggi.org/sites/default/files/Uploads/PressReleases/2021_04_02_FoCP_Compliance.pdf) (last visited Apr. 14, 2021).

2. VMA's argument that RGGI requirements are de facto rules is internally inconsistent, misapplies caselaw, and is a challenge to the Original Regulations, not the Amended Regulations.

VMA's second argument is that "RGGI requirements are de facto rules neatly eluding public notice or engagement in Virginia." VMA Brief at 24. There are three flaws with this argument. First, it is inconsistent with VMA's prior argument that the regulations are vague for failing to mention RGGI. Both statements cannot be true: regulations cannot be simultaneously vague for not using the word "RGGI" and vague for imposing RGGI.

The second flaw is that it misconstrues the concept of "de facto rules." VMA cites a single case regarding "de facto rules" — *Virginia Bd. Of Med. v. Virginia Physical Therapy Ass'n.*, 413 S.E.2d 59 (Va. Ct. App. 1991). *Id.* That case involved a determination of whether an informal "rule" adopted by the Board of Medicine constituted a "rule or regulation" under the APA. *Virginia Bd. of Medicine*, 413 S.E.2d at 64-65. In that context, the Court of Appeals discussed the concept of a "de facto rule," meaning, an agency action that the agency characterizes as something short of a final rule or regulation, but nonetheless, may constitute a rule or regulation under the APA. *Id.* That concept has no application here. The Amended Regulations are regulations. There

is no dispute. The Amended Regulations did not go through the APA process because the General Assembly expressly exempted them. Va. Code § 10.1-1330.A.

The third flaw in this argument, mentioned in Section A above, is that the *Original Regulations* imposed the requirements VMA now complains of. For example, VMA complains that the Amended Regulations require participants to comply with the requirements for RGGI COATS accounts. VMA Brief at 22. Yet the regulation VMA cites to make this argument, 9VAC5-140-6260, is substantially unchanged by the Amended Regulations. *See* Amended Regulations at 39-41 (showing the only change the Amended Regulations made to this provision is to remove reference to an "initial control period"). In other words, the Original Regulations imposed the same requirements VMA now claims to be unlawfully vague. Yet, the Original Regulations went through a full notice and comment process that VMA participated in and VMA chose not to pursue an APA appeal. Thus, VMA cannot now claim some sort of due process violation for a requirement that is not new. Moreover, the Original Regulations are not before the Court; thus, any alleged ambiguity is not at issue here.

3. VMA offers no evidence to support its claim that a "person of ordinary intelligence" could not comply with the Amended Regulations and the results of Virginia's first CO_2 auction demonstrate that VMA's claim is false.

VMA's third argument is that a "person of ordinary intelligence, in the Revision A20 program could not decipher the program requirements in general." VMA Brief at 23-24. This argument is flawed for two reasons. First, VMA has the burden of proof and, as discussed above, it is a very high burden for a vagueness claim. VMA points to no evidence in the record to substantiate this claim.

Second, this Court can take judicial notice[16] of media accounts of Virginia's first CO_2 auction which occurred earlier this year. As reported, Virginia generated over $43 million in revenue from the first auction and there were no reports of widespread confusion by participants.[17]

IV. VMA's tax claims fail because: (A) they are challenges to the Act, not the Amended Regulations; and (B) the revenue collected is not an illegal tax.

The fourth argument in VMA's Brief (and its fourth and fifth assignments of error in its Petition for Appeal) is that "requiring utilities to buy CO2 allowances to offset 100% of their annual tons of CO2 emissions" is an "illegal carbon tax on Virginia electricity ratepayers." VMA Brief at 25. There are two flaws with this argument. First, it is a challenge to the Act (and other statutes), not a challenge to the Amended Regulations. Second, utilities charging their customers for CO_2 allowances is not an illegal tax under Virginia law.

A. VMA's tax arguments are challenges to the Act, not the Amended Regulations; yet, VMA did not challenge the Act in this case.

According to VMA, "[t]he trading market, as structured under Revision A20, creates a carbon tax outside of the required taxation process." *Id.* Yet, "the trading market," that VMA describes was explicitly mandated by the General Assembly through the Act:

> The Director is hereby authorized to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article. The Director shall seek to sell 100 percent of all allowances issued each year through the allowance auction. . . .

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[16] Pursuant to Virginia Supreme Court Rule 2:201, this Court may take judicial notice of "a factual matter not subject to reasonable dispute in that it is either (1) common knowledge or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned." Va. Sup. R. 2:201(a) (2020).

[17] *See* Sarah Vogelsong, *Virginia Nets More than $43 Million in First Carbon Allowance Auction*, The Virginia Mercury (Mar. 9, 2021) (available at https://www.virginiamercury.com/blog-va/virginia-nets-more-than-43-million-in-first-carbon-allowance-auction/) (last visited Apr. 13, 2021). VMA has provided no evidence of widespread confusion in any of the other RGGI states since their adoption of similar regulations.

Va. Code § 10.1-1330.B. Thus, the General Assembly — not DEQ — created "the trading program" that VMA asserts is an illegal tax and the General Assembly mandated that the DEQ Director sell "100 percent" of all allowances through that program. Yet VMA did not challenge the Act.

VMA similarly argues that "the CECFPA directs the state treasury to hold the proceeds recovered from the allowance auction in an interest-bearing account," and by doing so, "the CECFPA specifically evades the general treasury." VMA Brief at 26. According to VMA, this evasion of the general treasury is unconstitutional. *Id.* But as VMA's own brief demonstrates, this is an argument against the Act, not the Amended Regulations. *Id.* ("the CECFPA specifically evades the general treasury…").

VMA did not challenge the constitutionality of the Act. Instead, VMA is asking this Court to set aside the Amended Regulations. But even if this Court did so, the Act would remain in place; thus, the "illegal tax" VMA claims exists would remain.

B. Even if the Act was before this Court, the General Assembly's authorization for utilities to include the costs of allowances in their rates is not an illegal tax.

VMA argues that "Revision A20 effectively *imposes a tax on electricity ratepayers* because the CECFPA provides for recovery of these costs through rates as environmental compliance project costs." VMA Brief at 25 (emphasis added). Not only is this argument, as discussed above, a challenge to the Act rather than to the Amended Regulations, this argument suffers from two additional defects: this provision is neither a tax nor illegal.

First, the Act mandates the creation of a CO_2 direct auction program. Va. Code § 10.1-1330.B. The potential added costs of electricity that ratepayers may pay utilities to comply with that program is not a tax under Virginia law. As the United States Court of Appeals for the Fourth Circuit reasoned in *Corr v. Metro. Wash. Airports Auth.*, 740 F.3d 295, 300 (4th Cir. 2013), in

assessing an illegal tax claim, "Virginia courts ask whether a given exaction is a bona fide fee-for-service or an invalid revenue-generating device." For example, tolls "are user fees and not taxes when they are nothing more than an authorized charge for the use of a special facility." *Id.* (quoting *Elizabeth River Crossings OpCo., LLC v. Meeks*, 749 S.E.2d 176, 183 (Va. 2013) (internal quotation marks omitted)). The rate that electricity customers pay an electricity utility is the "authorized charge" the customer pays in exchange for receiving the electricity. *Id.* The fact that the General Assembly, through the Act, has allowed utilities to include within that fee the costs of purchasing CO_2 allowances necessary to produce that electricity does not transform a customer's electricity bill into a tax.[18]

The second defect with VMA's argument is that even if passing on the costs of purchasing CO_2 allowances to ratepayers did constitute a tax, the General Assembly has the legal authority to levy taxes. *See* Va. Cont. Art. VII, § 7. *See also Wise Cty Bd. of Supervisors v. Wilson*, 250 Va. 482, 484 (1995) ("no entity other than an elected governing body may levy taxes"). The constitutional limitation on the General Assembly's taxing power is found in Article X, Section 7 of the Virginia Constitution, which states that "[n]o money shall be paid out of the State treasury except in pursuance of appropriations made by law." Va. Const. Art X, § 7. The Virginia Supreme Court has interpreted the term "appropriation" to mean "payment out of the state treasury." *Button v. Day*, 203 Va. 687, 695 (1962). Thus, taxes collected in Virginia can only be paid out of the state

[18] If VMA's argument were correct, every "environmental compliance project cost" that a utility includes in its costs of service would constitute an illegal tax on rate payers. For example, the General Assembly allows a utility to charge all its customers for the costs of projects that replace existing overhead powerlines with underground power lines. *See* Va. Code § 56-585.1.A.6. According to VMA, this cost sharing would be an illegal tax because it is a project cost that is paid for by all customers for a public need. Similarly, the General Assembly allows utilities to include the "cost of compliance" with renewable energy portfolio standards as part of its cost of service. Va. Code § 56-585.1.A.5.d. These costs, according to VMA's logic, would also constitute illegal taxes on electricity customers.

treasury if authorized by the General Assembly through the passage of a law. Here, the General Assembly did just that: it passed the Act. Specifically, Section 10.1-1330.C of the Act, begins with, "[t]o the extent permitted by Article X, Section 7 of the Constitution of Virginia," and then articulates exactly how proceeds from direct auctions are to be distributed. Thus, even if the Act were challenged in this case (which it is not), and even if requiring electricity customers to pay through electricity rates for the purchase of CO_2 allowances necessary to produce their electricity constituted a tax (which it does not), it is not an unconstitutional or illegal tax because the General Assembly explicitly directed how the proceeds should be distributed through a law.

V. VMA is not entitled to attorneys' fees under the APA or otherwise.

In its petition, VMA requests that this Court award it attorneys' fees that VMA incurred in bringing this action. VMA Pet. at 26. Pursuant to Virginia Code Section 2.2-4030, a party is only entitled to attorneys' fees in an APA appeal if "(i) the agency's position is not substantially justified, (ii) the agency action was in violation of law, or (iii) the agency action was for an improper purpose." Va. Code § 2.2-4030.A.

Here, none of these elements have been satisfied. As discussed above, DEQ's issuance of the Amended Regulations was mandated by the General Assembly through the Act and the Act expressly exempted the Amended Regulations from the APA. Thus, DEQ neither violated the law nor acted "for an improper purpose." *Id.* For all the reasons stated above, DEQ respectfully requests that this Court deny VMA's request for attorneys' fees.

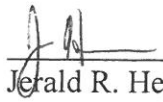
Conclusion

This case is important. In 2020, the Virginia General Assembly passed historic environmental legislation that addresses both the causes of climate change and its impact on vulnerable communities in Virginia. Part of that legislation required that DEQ amend the existing CO_2 budget trading program by moving to a direct auction model and then selling 100% of Virginia's CO_2 allowances in those auctions. The General Assembly expressly exempted these amendments from the APA. DEQ followed the General Assembly's mandate: it issued the Amended Regulations that made all necessary changes to the existing CO_2 Budget Trading Program. Now, DEQ is directly auctioning CO_2 allowances and the proceeds, which were over $43 million in the first auction, are going to support programs for low-income communities and vulnerable shorelines. This is exactly what the General Assembly legislated.

Yet this case is not complicated. VMA has challenged the Amended Regulations, but not the Act. Contrary to VMA's assertions, the Amended Regulations expressly follow the Act, they do not violate it. There can be no APA violation because the Act exempts the Amended Regulations from the APA. The Amended Regulations are not unlawfully vague. Finally, allowing utilities to charge their customers for the costs of CO_2 allowances is not an issue before this Court (because it is an issue that goes to the Act, not the Amended Regulations), and even if it was, doing so is not an illegal tax.

The Virginia General Assembly acted to address climate change and vulnerable communities in Virginia are receiving the benefit of these actions. This Court should not be persuaded to undermine this progress.

Respectfully submitted,



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I hereby certify that a copy of the above Brief in Opposition was served via certified mail and by electronic mail on May 7, 2021, on the following:

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Attachment 3

ENERGY + ENVIRONMENT
GENERAL ASSEMBLY 2020
GOVERNMENT + POLITICS

Virginia lawmakers agreed to join a regional carbon market. Here's what happens next.

By: Sarah Vogelsong - April 14, 2020 12:01 am

Coal fired units at Dominion Energy's Chesterfield Power Station would close by 2024 under the Clean Economy Act that passed the General Assembly in 2020. (Ryan M. Kelly/ For the Virginia Mercury)

A year after Republican resistance stalled Virginia's effort to cap carbon emissions from large producers of the greenhouse gas at the forefront of climate change, the wheels are again in motion: Virginia is joining the Regional Greenhouse Gas Initiative.

Joining the cap-and-invest program was one of Democrats' top legislative priorities for the 2020 General Assembly session. Thanks to their majorities in both the House of Delegates and the Senate, they achieved their goal on mostly, but not quite, party-line votes. Gov. Ralph Northam has also supported the state's participation, although several technical amendments he's proposed related to fund administration still have to be approved by the reconvened General Assembly next week.

"By joining RGGI, Virginia will take part in a proven, market-based program for reducing carbon pollution in a manner that protects consumers," Northam said in a statement Sunday. "I am proposing important refinements and I look forward to signing it into law soon."

Clearing these political hurdles, though, is only the beginning of the administration's work. Virginia will become a full participant in RGGI starting Jan. 1. Here's what will happen between now and then.

The caboose budget will be finalized, allowing the state to devote resources to joining RGGI

In 2019, Republicans blocked Virginia from joining RGGI by adding language to the budget that forbid the Department of Environmental Quality from spending any money "to support membership or participation in the Regional Greenhouse Gas Initiative until such time as the General Assembly has approved such membership."

The General Assembly has now approved such participation — but that approval doesn't go into effect until July 1, while the budget passed in 2019, with its prohibition on RGGI spending, remains in force.

That doesn't mean the state's hands are tied until July, however. The solution lies in the "caboose" budget, a bill that amends the last biennial budget and applies to spending through June 30, the last day of the fiscal year. The 2020 caboose budget, as might be expected, strips out the RGGI spending provision.

Last weekend, Northam returned the caboose bill to the General Assembly with 37 proposed amendments designed to help Virginia respond to the COVID-19 pandemic. None of the amendments are related to RGGI, but legislators will have to agree on a final version of the caboose budget when they reconvene April 22 before the administration can take any further action to join the initiative.

"We are anxiously awaiting the date and time where that becomes effective, because that will be sort of the starting gun for us," said DEQ Deputy Director Chris Bast.

The state's existing carbon regulation will be rewritten

Virginia already has a regulation on its books to govern how the state could operate in a carbon market. But because the General Assembly has to approve all state expenditures and

revenues, and the "carbon rule" was written before any such approval had been given, regulators had to devise a way for the state to participate in the RGGI market without spending or making any money.

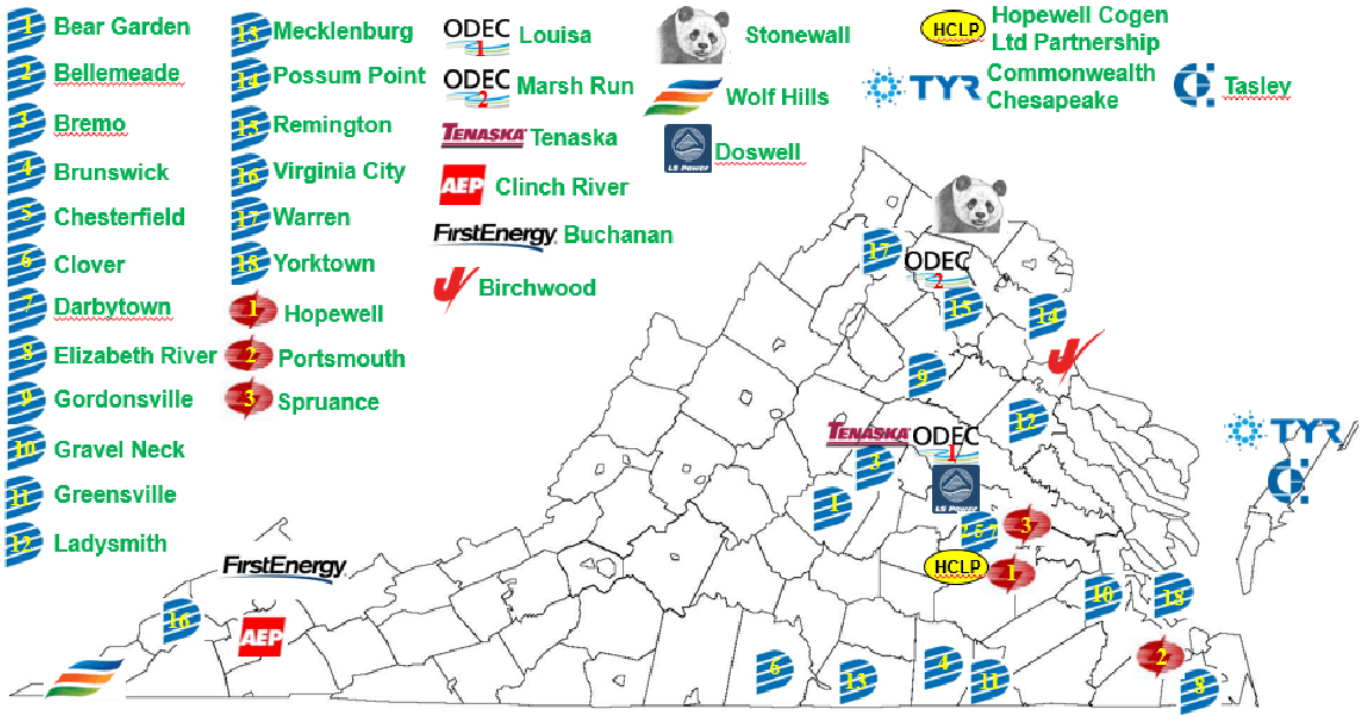
What they came up with was an elaborate workaround called a consignment auction. Under this plan the state would have distributed carbon allowances to emitters based on their historical emissions, and the emitters would then have been required to sell those allowances into the market while buying back what they needed.

It was "a very complicated regime that we had concocted. But it worked, or it would have worked," said Virginia Department of Environmental Quality Air Director Mike Dowd.

Now there's no need for that system. The legislation that cleared the General Assembly this session authorizes the state to take a simpler approach of directly auctioning off carbon allowances to emitters and then depositing the revenues of that auction in specific funds for energy efficiency, flood preparedness and other measures.

"We'll be doing what every other state in RGGI does," said Dowd.

With the existing carbon rule now out of date, DEQ will be charged with revising it to match the new law. To ease and speed up that process, the General Assembly has also allowed the agency to bypass the typical procedural requirements for changing regulations outlined in the Administrative Process Act.



Power plants covered under Virginia's carbon regulation. The unbuilt Chickahominy Power Station and C4GT facilities are not included. (Virginia Department of Environmental Quality presentation, October 2018)

Virginia will sign a contract with RGGI, Inc. and appoint two members to its Board of Directors

Once the budget restrictions are lifted, Virginia will be free to enter into talks with RGGI, Inc., the nonprofit organization that coordinates the states' participation in the program. Although RGGI, Inc. has no regulatory authority of its own — its role is administrative and technical — it is the hub through which Virginia will finalize the details of how it will participate in the regional carbon market.

Some of the outstanding issues to be resolved, said Dowd, include Virginia's contribution to the overall program's annual administrative costs, the process of transferring allowances and confirmation that the state's system will work smoothly with the regional one.

Why RGGI states are called "participants," not "members"

Although this reporter and others have frequently referred to the 10 New England and Mid-Atlantic states that are part of RGGI as "members" of the program, the states staunchly insist they are "participants," a distinction intended to keep them from running afoul of the Compact Clause of the U.S. Constitution.

This Article I clause declares that "No State shall, without the Consent of Congress, … enter into any Agreement or Compact with another State."

That might seem to be an insurmountable barrier to the kind of agreement RGGI is built on. But, as the *Harvard Law Review* observed, "no court has ever invalidated an interstate agreement for lack of [congressional] consent," and "the Supreme Court has long maintained that not every arrangement that might be considered an 'agreement or compact' in the modern meaning of the terms requires congressional consent."

Despite legal challenges to RGGI from the electric industry and other parties, no ruling to date has struck down the effort. Many scholars and policymakers have accepted that the initiative does not violate the Compact Clause based on three key points. First, RGGI, Inc. has no regulatory or enforcement authority. Second, every state that participates in RGGI does so by adopting its own independent legislation, albeit legislation based on a consistent Model Rule. And third, any state is free to exit or enter RGGI as it sees fit, as the case of New Jersey — which voted to withdraw from RGGI in 2011 and then, in 2019, to rejoin it — illustrates.

As DEQ Air Director Mike Dowd put it, RGGI "is in large measure a gentleman's agreement among the participating states."

"These are the details that we haven't been able to talk about with RGGI for the last year," he said.

Northam will also appoint two people to the RGGI, Inc. Board of Directors, which usually includes each state's environmental agency head and the leader of its energy regulatory body.

"RGGI's a consensus organization. It's not the type of organization that operates by a majority-rule vote," said Bast. Joining the board, he said, will ensure Virginia has a seat at the table in future decisions, including those related to Pennsylvania's pending linkage with the market.

Carbon emitters will prepare for auctions and compliance obligations

All fossil fuel plants with a capacity of 25 or more megawatts will be required to buy carbon allowances to cover their emissions once Virginia begins fully participating in the market Jan. 1 — a cost the legislature will allow utilities to pass directly onto their customers, with no extra returns for investors.

In February, Dominion estimated RGGI compliance would raise the average customer's monthly bill by $1.22 over the next five years, while the State Corporation Commission estimated monthly bills will increase between $2 and $2.50.

These facilities will also need to ready themselves for regular compliance reporting to ensure they are purchasing enough allowances and monitoring their emissions appropriately.

Because RGGI auctions are held quarterly and the first won't occur until March 2021, there might appear to be a lag between the program's requirements and the first chance emitters have to meet them. Compliance with RGGI limits, however, is assessed on a three-year basis (although emitters do have to meet certain targets during that time).

This design gives facilities some flexibility: as long as they can prove they hit their targets and held the necessary number of allowances over that period, they will be in the clear.

Between the quarterly auctions, businesses can also buy and sell allowances on RGGI's secondary market. Some Virginia emitters, officials believe, may already be storing them up for Jan. 1.

State modeling will be updated

State models developed during the crafting of the original carbon regulation will be updated to match what Bast called the "new reality" in Virginia, one shaped by Northam's goal of weaning the state's electric grid off fossil fuels by midcentury, the shift from a compliance auction system to a direct one, and passage of the Virginia Clean Economy Act, which sets hard targets for utilities to develop renewable resources and encourage energy efficiency.

All of those factors will change estimates of what RGGI compliance will cost Virginians, as well as what revenues it will produce.

"The emissions cap and the clean energy standard in the Clean Economy Act really do work hand in hand," said Bast. "The sum is greater than its parts."

Other modeling will likely occur on the regional level, as the RGGI states assess how the participation of a large emitter like Virginia will affect the broader market.

RGGI Director of Program Administration Anna Ngai said in an email this March that the other states "recognize the benefits of a broader market with more participants, as larger markets increase economic efficiency and cost-effectiveness."

While the list of hoops for the state to jump through before Jan. 1 may be long, Dowd said he had few doubts the process would be completed in time.

"There are no problems that we see on the horizon that would in any way hinder our full participation starting next year," he said.

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Attachment 4

VIRGINIA CLEAN ENERGY AND COMMUNITY FLOOD PREPAREDNESS ACT

A Joint Report to Governor Ralph S. Northam
and the General Assembly of Virginia

Department of Environmental Quality
Department of Housing and Community Development
Department of Conservation and Recreation
Department of Energy

DECEMBER 2021

EXECUTIVE SUMMARY

This report was prepared pursuant to § 10.1-1330 of the Code of Virginia which directs the Department of Environmental Quality (DEQ), the Department of Conservation and Recreation (DCR), the Department of Housing and Community Development (DHCD), and the Department of Energy (DOE) to, beginning January 1, 2022, annually prepare a joint annual written report describing the Commonwealth's participation in the Regional Greenhouse Gas Initiative, the annual reduction in greenhouse gas emissions, the revenues collected and deposited in the interest-bearing account maintained by the Department of Environmental Quality pursuant to the Clean Energy and Community Flood Preparedness Act, and a description of each way in which money was expended during the fiscal year.

SECTION 1 – DEPARTMENT OF ENVIRONMENTAL QUALITY

1.1 Introduction

Signed in April 2020 by Governor Northam, the Clean Energy and Community Flood Preparedness Act (CECFPA) directed DEQ to establish through regulation a carbon dioxide (CO_2) cap and trade program to reduce emissions released by electric generation facilities. The Act also authorizes Virginia to link its cap and trade program to the larger Regional Greenhouse Gas Initiative (RGGI).

Several executive actions concerning the development of a market-based mechanism to reduce carbon pollution preceded the signing of the Clean Energy and Community Flood Preparedness Act. Executive Order 57, signed by Governor McAuliffe in 2016, directed the Secretary of Natural Resources to convene a work group to study and recommend methods to reduce CO_2 from electric power facilities and grow the clean energy economy within existing state authority. This group facilitated extensive stakeholder engagement before submitting a final report with recommendations to the Governor.

Subsequently, in 2017, Governor McAuliffe signed Executive Directive 11, titled, “Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia’s Clean Energy Economy.” This order directed DEQ to develop a regulation to control CO_2 from electric power facilities that allows for the use of market-based mechanisms and the trading of CO_2 allowances through a multi-state trading program.

Although the regulation was officially adopted in 2019, language in the 2019 budget effectively suspended its implementation. Then, as noted above, during the 2020 Session, the General Assembly passed the Clean Energy and Community Flood Preparedness Act. Pursuant to the Act, DEQ adopted a revised regulation in June 2020 that converted the Carbon Trading Program from the prior consignment-based model to a direct auction trading system. The regulation was subject to a legal challenge in the Circuit Court for the City of Richmond. The Circuit Court upheld the regulation in July 2021.

1.2 Overview of the Carbon Trading Program

Virginia has chosen to implement its carbon trading rule pursuant to Clean Energy and

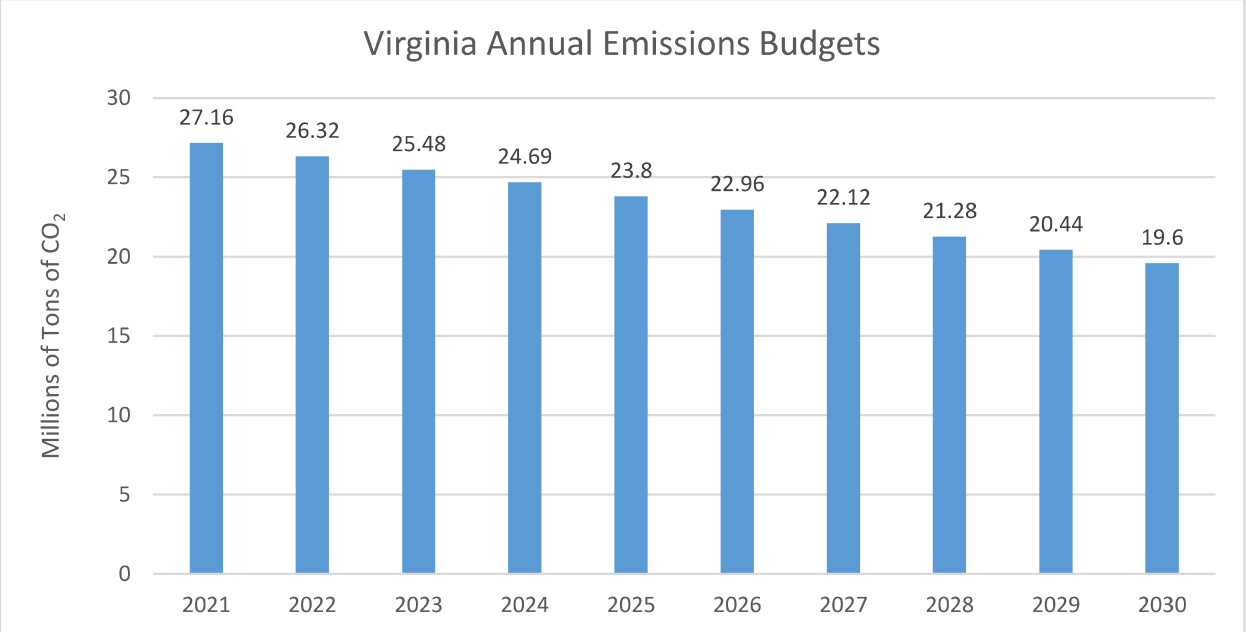
Community Flood Preparedness Act by participating in the Regional Greenhouse Gas Initiative, which currently has 11 participating states in the mid-Atlantic, and New England.

The RGGI program serves a dual purpose in that it is a cap and trade program for regulated sources where allowances can be purchased for each ton of CO_2 emissions. These allowances can then be used for compliance purposes, banked for future use, or traded to other sources. These allowances are fully fungible and can be used throughout the RGGI program area. At the end of each three-year compliance period, regulated sources must surrender the number of allowances equal to their CO_2 emissions during the compliance period.

For participating states, the RGGI program serves as a cap and invest program where each state offers their allowances based on established emissions budgets for sale during quarterly auctions. As these emission budgets decrease over time, so do the regional CO_2 emissions. The proceeds from the auctions are returned to the states to fund climate related programs.

The Virginia Carbon Trading Program regulation establishes a declining annual budget on carbon dioxide emissions from power plants consistent with the RGGI reduction goals. To comply with the regulation, power generators must reduce emissions and purchase allowances through quarterly auctions administered by RGGI, Inc., the curating non-profit organization for the RGGI program, on behalf of DEQ. Emissions reductions are secured as the budget is lowered over time. From 2020 to 2030, the power sector emissions budgets among Virginia and the RGGI states will decrease by 30%. Virginia's annual emissions budgets are shown in Table 1.

Figure 1: Virginia Carbon Trading Rule Annual Budgets



Source: Virginia Carbon Trading Program Regulation

The Clean Energy and Community Flood Preparedness Act provides that 45% and 50% of the proceeds generated from the auctions are used to fund the Virginia Community Flood Preparedness Fund (CFPF) and the Housing Innovations in Energy Efficiency (HIEE) program,

respectively. The CFPF helps localities across the Commonwealth reduce the impacts of flooding by implementing flood prevention and protection projects. The HIEE program makes energy efficiency upgrades to new and existing residential buildings to reduce energy bills for low-income Virginians. DEQ receives 3% of auction revenues to cover administrative expenses related to running the Program and to carry out statewide climate change planning and mitigation activities. The Department of Housing and Community Development, in partnership with the Virginia Department of Energy, receives 2% of the proceeds to administer and implement the low-income energy efficiency programs.

Virginia's participation in RGGI is expected to facilitate Virginia's energy transition and the goal of achieving 100% carbon-free electricity generation by 2045 set forth in the Virginia Clean Economy Act.

1.3 Sources Affected in Virginia

A total of 27 electric generating facilities in Virginia are currently subject to the carbon trading rule. The combined capacity of these facilities is 19,922 megawatts (MWs) and their combined emissions in 2020 were 31.4 million tons of CO_2. In terms of fuel specific generation, 2,827 MWs of coal-fired generation emitted 4.4 million tons of CO_2, 14,765 MWs of natural gas-fired combine cycle generation emitted 26.9 million tons of CO_2, and 2,330 MWs of oil-fired generation emitted 0.1 million tons of CO_2. A list and map of the affected sources in Virginia are presented in Table 1 and Figure 2. Some sources are not visible on the map due to their proximity to each other.

Table 1: RGGI Sources in Virginia

	County	Plant Name	Capacity (MW)	2020 CO_2 Emissions (Tons)
1	Buckingham	Bear Garden Generating Station	559	1,805,606
2	King George	Birchwood Power Facility	258	108,616
3	Brunswick	Brunswick County Power Station	1,472	4,135,381
4	Buchanan	Buchanan Units 1 & 2	88	258,931
5	Chesterfield	Chesterfield Power Station	1,500	2,020,768
6	Russell	Clinch River	475	184,040
7	Halifax	Clover Power Station	848	1,432,252
8	Accomack	Commonwealth Chesapeake	403	20,758
9	Henrico	Darbytown Combustion Turbine	368	80,893
10	Hanover	Doswell Limited Partnership	1,313	3,097,621
11	Chesapeake City	Elizabeth River Combustion Turbine	389	63,055
12	Louisa	Gordonsville Power Station	300	594,369
13	Surry	Gravel Neck Combustion Turbine	408	113,015
14	Greensville	Greensville County Power Station	1,773	4,189,822
15	Hopewell	Hopewell Cogeneration Facility	399	1,025,984
16	Caroline	Ladysmith Combustion Turbine Station	893	682,849
17	Louisa	Louisa Generation Facility	509	238,055
18	Fauquier	Marsh Run Generation Facility	513	355,517
19	Loudoun	Panda Stonewall Power Project	812	2,012,751
20	Prince William	Possum Point Power Station	1,591	1,604,137

21	Fauquier	Remington Combustion Turbine Station	706	419,714
22	Accomack	Tasley Energy Center	27	0
23	Fluvanna	Tenaska Generating Station	1,011	1,925,324
24	Wise	Virginia City Hybrid Energy Center	668	1,109,652
25	Warren	Warren County Power Station	1,472	3,747,811
26	Washington	Wolf Hills Energy	285	68,266
27	York	Yorktown Power Station	882	62,396
		TOTALS	**19,922**	**31,357,583**

Source: EPA Air Markets Program Data, EIA Form 860

Figure 2: RGGI Regulated Sources

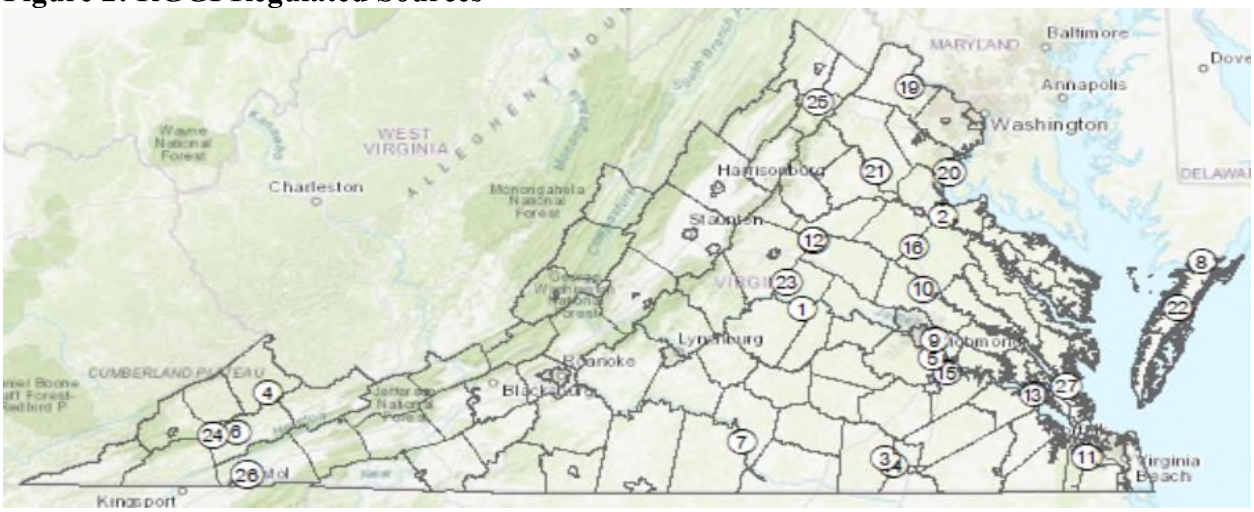
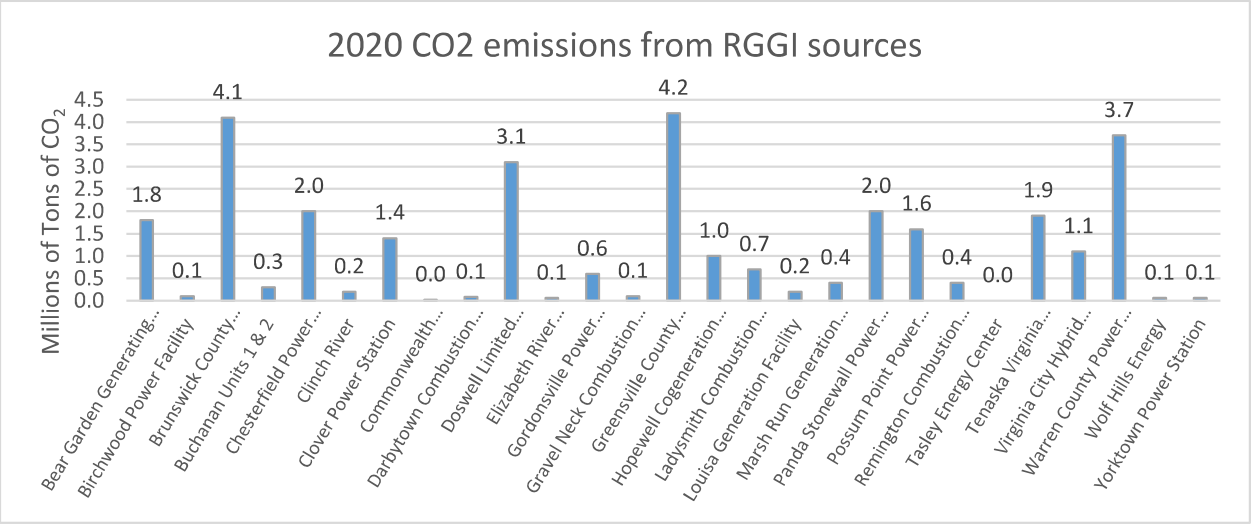


Figure 3 shows the 2020 emissions from each of the sources regulated under the carbon-trading rule. The largest CO_2 emitting sources in Virginia in 2020 were newly constructed and highly efficient combined cycle natural gas-fired facilities. Further discussion of the transition of the Virginia power sector to more efficient and less-polluting generation is available in Section 1.4.

Figure 3: 2020 CO_2 Emissions from RGGI Sources



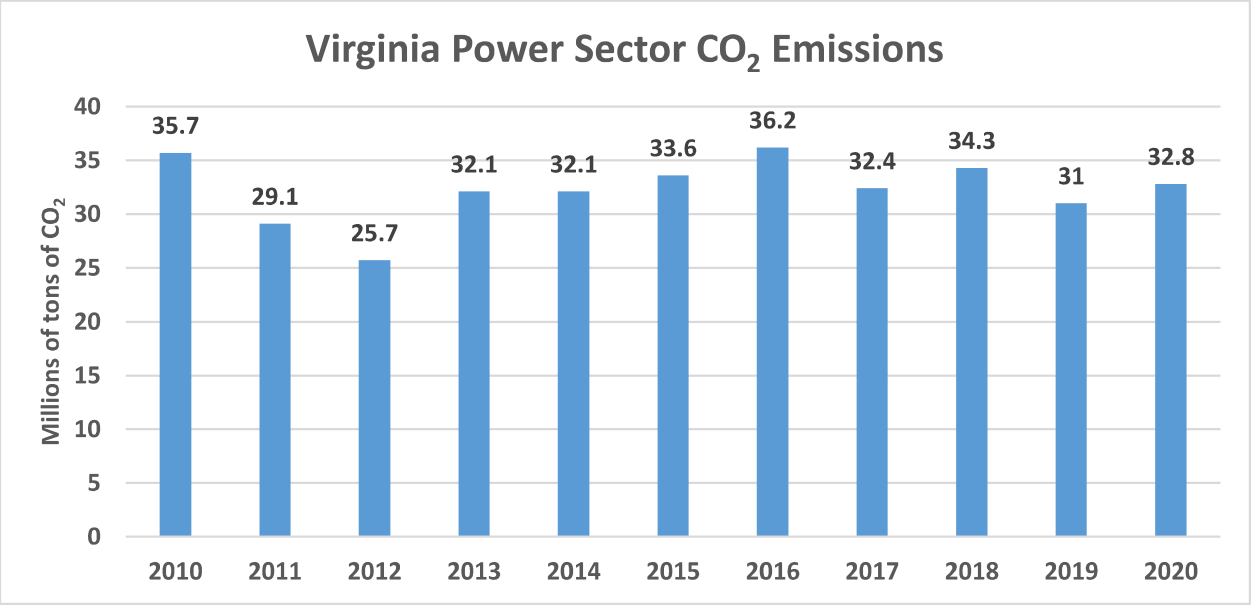
Source: EPA Air Markets Program Data

1.4 Virginia Power Sector Trends

The Virginia power sector historically produced the majority of electricity generation and carbon emissions from the combustion of coal. In 2005, half of the total electricity generation and 80% of CO_2 emissions came from coal-fired units and facilities. Since then, a transition in the Virginia power sector has occurred with coal being replaced with cleaner burning natural gas, and the introduction of renewables. Natural gas overtook coal as the largest fossil fuel generation source in 2012. The other major in-state electricity source is zero-carbon emitting nuclear generation from two nuclear plants in Virginia. The level of nuclear generation has remained mostly constant over the years. To further document this transition a series of figures are presented below.

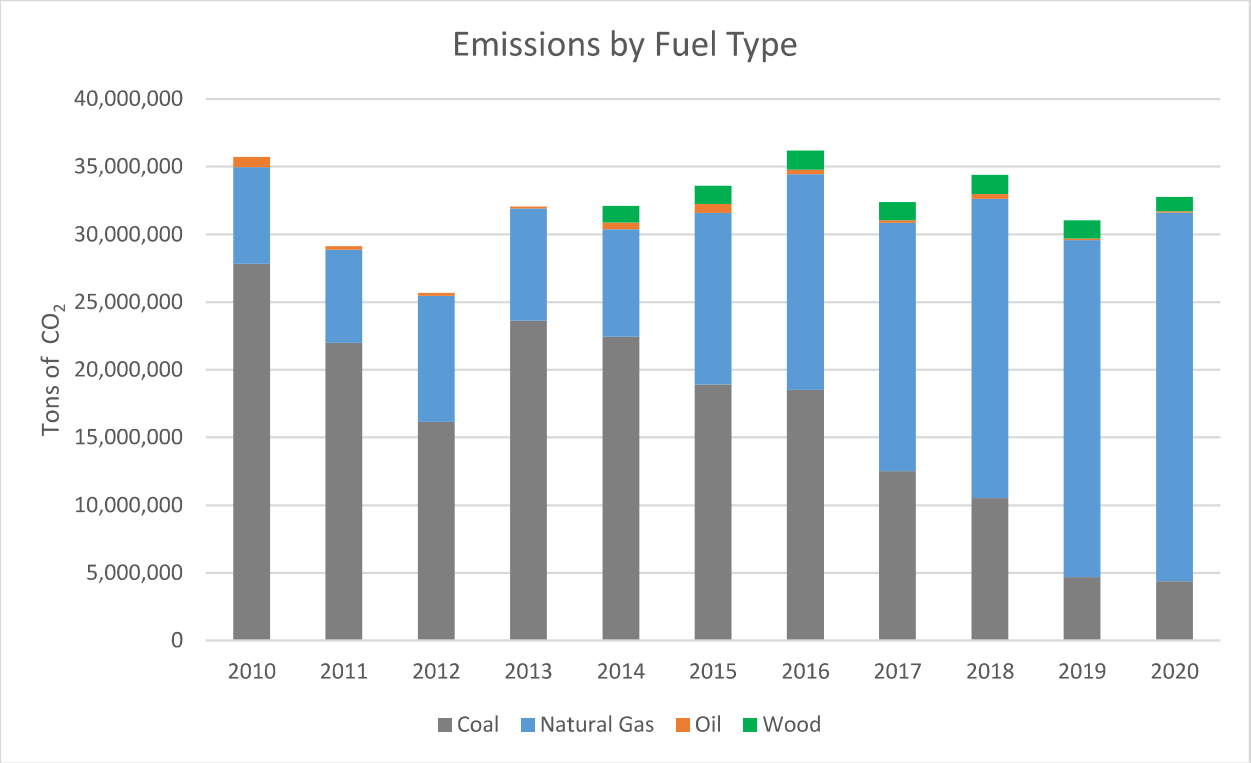
- Figure 4 shows the CO_2 emissions from the Virginia power sector from 2010 to 2020. Sector emissions have varied from year to year due to normal factors such as seasonal weather conditions and changes in electricity demand with no obvious trend either up or down. At first this would seem to contradict the transition from coal to cleaner natural gas generation. Much of the continuing levels of power sector CO_2 emissions is due to the addition of a substantial amount of natural gas generation capacity during this ten-year period with a corresponding increase of in-state electricity generation which has also reduced the amount of power imported into Virginia as shown in the next two figures.
- Figure 5 shows the same total emissions by year and broken down by fuel use. This shows the decrease in CO_2 emissions from coal generation and increase in emissions from increased natural gas generation.
- Figure 6 most noticeably shows the power sector transition with the large decrease in coal generation, and even larger increase in natural gas generation and overall in-state generation.

Figure 4: Total Virginia Power Sector CO_2 Emissions 2010-2020



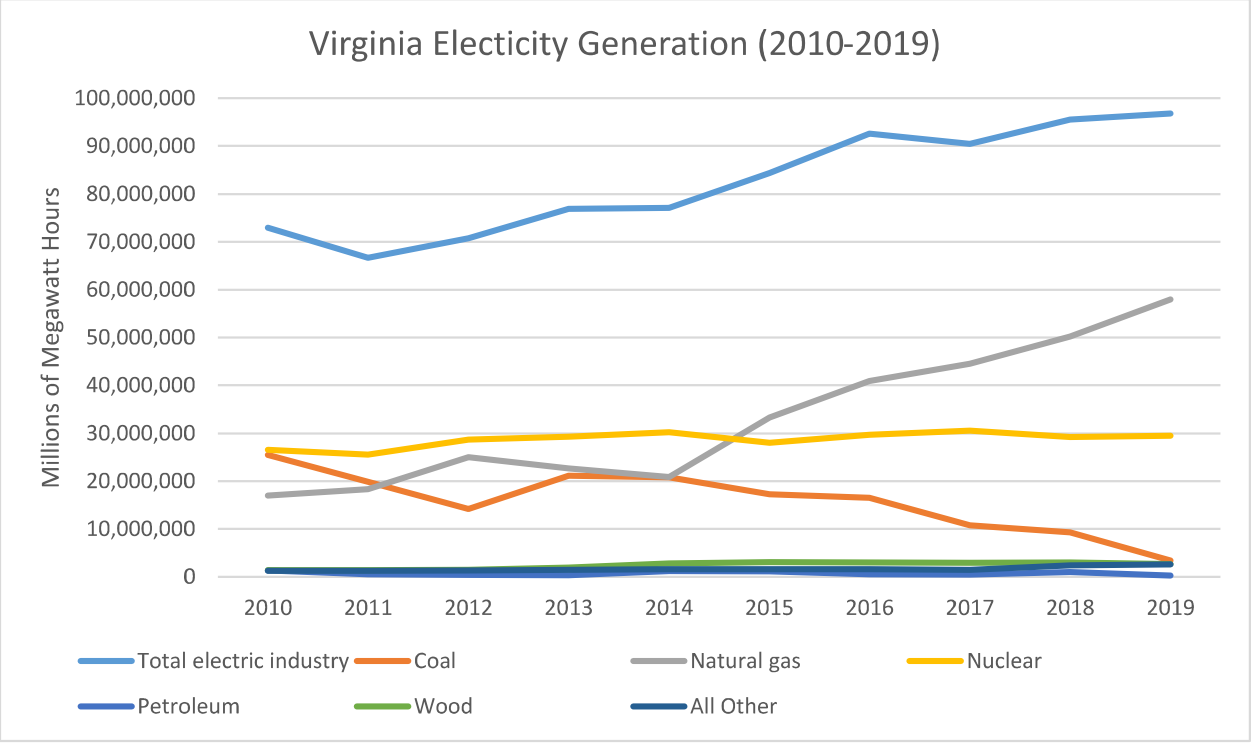
Source: EPA Air Markets Program Data

Figure 5: Power Sector Emissions by Fuel Type 2010-2020



Source: EPA Air Markets Program Data

Figure 6: Electricity Generation in Virginia by Fuel Type 2010-2019



Source: EIA State Energy Profile

Looking towards the future, it is expected that Virginia's power sector CO_2 emissions will steadily decrease due to the combination of the decreasing annual emissions caps of the RGGI program and the long term clean energy requirements and goals of the Virginia Clean Economy Act.

The RGGI program is currently under review, which could yield changes in program reduction targets going forward, and in other notable program components such as environmental justice considerations. This program review is expected to be completed in 2023.

The Virginia Clean Economy Act (VCEA) sets forth specific mandates for the power sector including the shutter of most of the remaining coal and biomass electric generating facilities in Virginia, along with specific renewable energy generation targets and standards. Implementation of the Virginia Clean Economy Act is expected to lead to a carbon free power sector in the 2045-2050 timeframe. The Virginia Department of Energy (previously the Department of Mines, Minerals, and Energy) is currently conducting a study of the Virginia power sector going forward under the requirements of the VCEA that supports this conclusion. More information on that study can be found at https://www.energy.virginia.gov/environmental/decarbonization.shtml.

1.5 Source Specific Power Sector Changes

A number of source specific changes have occurred in Virginia's mix of power generation that will impact current and future emissions and generation trends. These changes, identified as closures and fuel conversions, are presented below in Table 2. From 2010 to 2020, six coal facilities closed, while five large combined cycle natural gas facilities have opened. Three coal facilities converted to biomass (wood) and one converted to gas.

The impact of these changes is shown in Figure 7. During the 2010 to 2020 period, operating coal generation capacity has decreased but there has been a corresponding increase in natural gas capacity of over 5,000 megawatts.

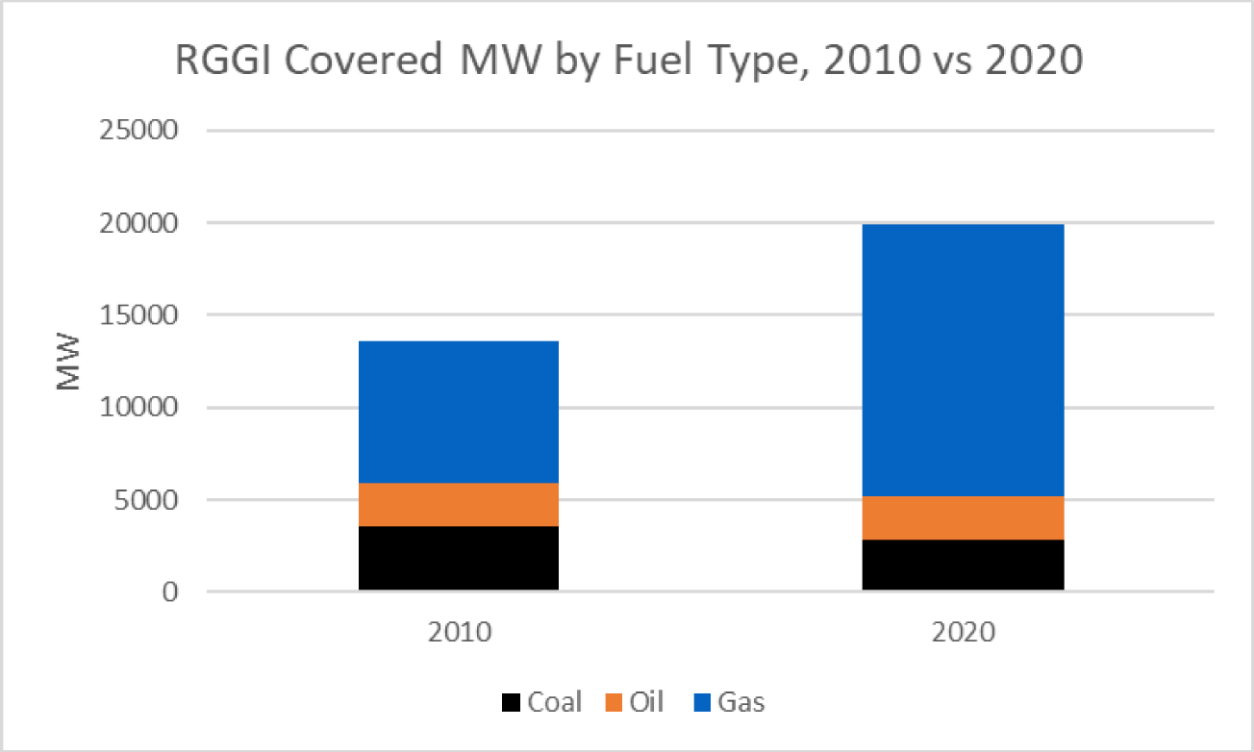
Table 2: Changes to Power Generation Sources in Virginia (2010-2020)

Plant Name	Change In Operation/Fuel	Year
Bear Garden Generating Station	Gas facility began operating	2011
Potomac River	Coal facility permanently closed	2012
Virginia City Hybrid Energy Center	Coal/biomass facility began operating	2012
Hopewell Power Station	Converted to biomass (wood) from coal	2013
NOVEC Halifax County Biomass Plant	Biomass facility began operating	2013
Southampton Power Station	Converted to biomass (wood) from coal	2013
Altavista Power Station	Converted to biomass (wood) from coal	2014
Bremo Power Station	Converted to gas from coal	2014
Chesapeake Energy Center	Coal facility permanently closed	2014
Warren County Power Station	Gas facility began operating	2014
Clinch River	Coal unit 3 retired, units 1 and 2 converted to gas	2015
Glen Lyn	Coal facility permanently closed	2015

Portsmouth Genco LLC	Coal facility permanently closed	2015
Brunswick County Power Station	Gas facility began operating	2016
Panda Stonewall Power Project	Gas facility began operating	2017
Bellemeade Power Station	Gas facility permanently closed	2018
Bremo Power Station	Gas facility permanently closed	2018
Chesterfield Power Station	Coal units 3 and 4 permanently closed	2018
Greensville County Power Station	Gas facility began operating	2018
Mecklenburg Power Station	Coal facility permanently closed	2018
Possum Point Power Station	Gas units 3 and 4 retired	2018
City Point Energy Center	Coal facility permanently closed	2019
Yorktown Power Station	Coal units 1 and 2 retired	2019
Possum Point Power Station	Oil unit 5 retired	2020

Source: PJM Generation Deactivations, EPA Air Markets Program Data tool

Figure 7: RGGI Covered Generation Capacity by Fuel Type 2010 and 2020



Source: EPA Air Markets Program Data tool, EIA Form 860

1.6 Regional Greenhouse Gas Initiative Auctions

RGGI, Inc. administers quarterly auctions on behalf of the RGGI states where it offers allowances for sale to compliance entities and other groups. Virginia first participated in Auction 51, which was held on March 3, 2021, and the Commonwealth has participated in three additional auctions for a total of four. A summary of auction results for 2021 is available in Table 3, and a distribution of funds raised from auctions is shown in Table 4.

It should be noted that RGGI, Inc. receives a small portion of Virginia's quarterly auction

proceeds to fund its annual operating budget. Virginia's total payment to RGGI, Inc. for 2021 is $592,920.08.

Table 3: 2021 Auction Results Summary

	Allowances Sold	Allowance Price	Allowance Proceeds
Auction #51	5,735,509	$7.60	$43,589,868.40
Auction #52	5,698,446	$7.97	$45,416,614.62
Auction #53	5,698,445	$9.30	$52,995,538.50
Auction #54	6,587,274	$13.00	$85,634,562.00
Total	23,719,674		$227,636,583.52

Table 4: Distribution of Funding

	RGGI	DHCD	DCR	DEQ	DHCD Admin
#51	$148,230.02	$21,720,819.19	$19,548,737.27	$1,303,249.15	$868,832.77
#52	$148,230.02	$22,634,192.30	$20,379,773.07	$1,358,051.54	$905,367.69
#53	$148,230.02	$26,423,654.24	$23,781,288.82	$1,585,419.25	$1,056,946.17
#54	$148,230.02	$42,743,165.99	$38,468,849.39	$2,564,589.96	$1,709,726.64
Total	$592,920.08	$113,521,831.72	$102,178,648.55	$6,811,309.90	$4,540,873.27

SECTION 2 – DEPARTMENT OF HOUSING AND COMMUNITY DEVELOPMENT

2.1 Stakeholder Advisory Group and Housing Innovations in Energy Efficiency (HIEE) Program Development Framework

The Department of Housing and Community Development (DHCD) prepared for investments of Regional Greenhouse Gas Initiative (RGGI) funds by choosing to brand the RGGI funds the agency would manage as Housing Innovations in Energy Efficiency (or HIEE) funding. The HIEE label would also allow for differentiation between RGGI funds managed by the Department of Conservation and Recreation (DCR).

To facilitate a transparent program development process for the public and stakeholder groups, DHCD convened a broad-based, 15-member HIEE Stakeholder Advisory Group (SAG), with representatives from affordable housing developers, consumer and environmental advocacy groups, weatherization providers, academia, and subject matter experts on energy efficient buildings. SAG members were selected from a list of over 100 parties that expressed interest in participating via DHCD's website. The SAG met monthly starting in December, 2020, to provide input and guidance to DHCD on the HIEE program development process and RGGI funding allocations. All SAG meetings were open to the public and recorded, and public comments were taken both verbally during the meetings and in writing. Meeting recordings and presentation materials are available on the HIEE webpage.

DHCD and the Stakeholder Advisory Group reached general agreement during the first two meetings on the principle that channeling HIEE funds through existing affordable housing programs would be the most efficient and effective means to quickly deploy resources to serve Virginians. The process of developing and standing up a new and separate program (or programs) could cause delay, and be a source of potential market confusion. The HIEE funds offer additional resources for project developers to achieve higher energy efficiency performance, or "additionality," a concept that expresses the improved outcomes that would not have occurred absent an incentive.

HIEE Stakeholder Advisory Group Members:

- Liz Beardsley, US Green Building Council
- Nate Benforado, Southern Environmental Law Center
- Carmen Bingham, Virginia Poverty Law Center
- KC Bleile, Viridiant
- Janaka Casper, Community Housing Partners
- Eric Claville, Norfolk State University
- Michelle Foster, Home Innovation Research Lab
- Chelsea Harnish, Virginia Energy Efficiency Council

- Dawone Robinson, Natural Resources Defense Council
- Sunshine Mathon, Piedmont Housing Alliance
- Brian Staub, Marlyn Development Corporation
- Adam Stockmaster, TM Development Corporation
- Narissa Turner, Virginia Conservation Network
- Karen Wilds, Newport News Redevelopment and Housing Authority

The final SAG meeting will occur in December 2021, and starting in 2022, the SAG will no longer meet as currently configured. Instead, DHCD will transition to twice-yearly (spring and summer) HIEE public input sessions open to all interested stakeholders. The two annual input sessions are consistent with practices in other established DHCD programs and will allow for comments on upcoming fiscal year allocations of HIEE funds and any proposed program adjustments.

2.2 HIEE Program Investments and Funding Allocation Percentages

As this report is prepared, four RGGI auctions have taken place in 2021: March 3, June 2, September 8, and December 1. Net RGGI proceeds (50 percent to programs) to DHCD are $113,521,832. RGGI auction clearing prices for these auctions have been significantly higher than initially predicted in late 2020, so net proceeds have been greater than expected.

DHCD has used the RGGI administrative funds (2 percent of net proceeds or $2,833,694) to begin staffing the Energy Efficiency Office, a new team in the Community Development and Housing Division, which is tasked with overseeing implementation of the HIEE funding across multiple programs and creating new programs. Three staff positions are filled at the time of this report (Associate Director, Program Administrator, and Technical Monitor-Inspector) with additional in process.

Because actual RGGI revenues received depend on each quarterly auction's clearing price and the number of allowances offered, DHCD proposed three funding components for the HIEE funding and allocation percentages that would guide the overall level of investment per fiscal year. This approach was supported by consensus of the SAG. Table 1 provides percentage allocations and actual obligations for Fiscal Year 2021 HIEE funds. More detail on these HIEE program funding investments is provided below the table.

Table 2.1 – Fiscal Year 2021 HIEE investments

HIEE Component	**Fiscal Year '21 - % HIEE allocation**	**Net to DHCD** *($21.7m from March, 2021 auction)*	**Actual Allocation** *(total $21.1m)*

Weatherization Deferral Repair (WDR) Program	60%	$13.0m	$15.2m
Affordable and Special Needs Housing (ASNH) Program	40%	$8.7m	$5.9m
Housing Energy Efficiency Partnerships Grants	0%	$0 m	$0

1. Weatherization Deferral Repair (WDR) program

WDR utilizes HIEE funds for incidental repairs to reduce deferrals and increase access to services through DHCD's Weatherization Assistance Program (WAP). The purpose of the WDR program is to make repairs that have caused homes (or units in multifamily buildings) to be deferred from the WAP because of restrictions on use of federal funds. Once needed repairs are made and the weatherization grantee deems the home or building "weatherization-ready," the energy efficiency and health and safety measures available through WAP (such as insulation, air sealing, energy efficient light bulbs, and carbon monoxide detectors) may be installed. Clients must sign an agreement with the weatherization agency, agreeing to both the WDR repairs and the weatherization services.

The WDR program is delivered by the network of 17 local weatherization agency grantees, and clients must work with the local weatherization agency serving their area through the WAP. DHCD has grant agreements in place with all of the weatherization agencies for use of the HIEE funds to provide WDR services statewide. Because WAP is a federally funded and regulated program, separate agreements were established with the weatherization agencies for WDR.

Based on information provided to DHCD by the weatherization agencies, approximately 350 single-family homes and 700 dwelling units in multi-family buildings have deferral repairs needed and may be served through the WDR program. In order to qualify for WDR, clients must meet WAP income eligibility requirements (household income must be at or below 60 percent of state median income) and have an energy audit done.

The Weatherization Deferral Repair Program Guidelines are available, here.

2. Affordable and Special Needs Housing Program (ASNH)

HIEE funds are available through DHCD's Affordable and Special Needs Housing (ASNH) program to support development of new affordable housing units and renovation of existing buildings providing affordable housing. HIEE funds are offered as forgivable, no-interest loans to developers to significantly increase energy efficiency in the housing units built or preserved. In order to receive HIEE funds, developers must provide a fundable ASNH application, which qualifies for at least one of the four traditional funding sources available under ASNH (National Housing Trust, HOME, Virginia Housing Trust Fund, or State Permanent Supportive Housing) and must demonstrate the building is designed to meet the additional HIEE performance criteria. Developers may receive HIEE funds up to 10 percent of total construction costs, with a cap of $2 million per qualifying project. The HIEE performance criteria (shown in Table 2 below) were developed ahead of the spring, 2021 ASNH application round in consultation with the SAG, and build upon the existing energy efficiency performance requirements of Virginia Housing's Low-Income Housing Tax Credit (LIHTC) program.

Low- to moderate-income Virginians benefit from the HIEE funds available through ASNH by having access to affordable rental housing units that are more energy efficient and offer improved indoor air quality. For example, $5.9 million in HIEE funds obligated through the spring 2021 ASNH application round provided additional funding to 11 projects, comprising over 700 dwelling units of either new or substantially renovated affordable housing. Energy modeling conducted on behalf of DHCD by Virginia Tech's Center for Housing Research predicts that occupants of typical newly constructed apartments in an affordable housing project will save about $200 annually in energy costs by virtue of the HIEE requirement for Zero Energy Ready Homes level of performance.

Guidelines for the 2021-2022 Affordable and Special Needs Housing Program including the HIEE requirements are available, here.

Table 2.2 – HIEE Additional Energy Efficiency Requirements for ASNH projects

Project Type	VA Housing Low-income Housing Tax Credit (LIHTC) Program Requirements	HIEE Requirements
New Construction	ENERGY STAR v3.0	Zero Energy Ready Homes (ZERH)

Substantial Rehab	30% improvement in HERS* index or HERS index 80 (or below)	40% improvement in HERS index or average of HERS 70 (or below) across all units
Adaptive Reuse	HERS index 95 (or below)	Average of HERS 80 (or below) across all units

**HERS refers to the Home Energy Rating System, a national standard used to evaluate and compare energy efficiency performance across housing sizes and types. Similar to an MPG rating on a vehicle, the HERS index predicts energy use under typical building operating conditions.*

3. Housing Energy Efficiency Partnerships Grants

The purpose of the Housing Energy Efficiency Partnerships grant program is to utilize a portion of the HIEE funding to find new pathways, methods, and work processes for preserving, upgrading and maintaining existing affordable housing stock to significantly reduce energy burdens on low-income households, for both rental and owner-occupied housing units. This grant program will provide resources and facilitate new partnership opportunities to demonstrate innovative and scalable approaches to reducing energy use, carbon emissions and occupant energy burdens through deep energy efficiency retrofits of existing residential buildings designated as affordable housing and physically located in Virginia. Local governments, tribal governments, non-profits, community-based organizations, academic institutions, and other affordable housing industry partners will be eligible to apply and/or partner on applications.

The program draft proposal was reviewed and commented on by the SAG in May, 2021. The program proposal was revised and reformatted as a grant application process with application instructions and review criteria. The grant application process will go through a 30-day public comment period starting on October 11. If there are no significant comments or changes, the grant application will be opened up in DHCD's Centralized Application Management System (CAMS) shortly thereafter.

The goal of the initial round of grants will be to demonstrate a deep energy retrofit approach that results in 50 percent reduction in occupant energy costs over a one-year period. Eligible building configurations include:

- Multi-family buildings of any size (renter tenants)
- Groups of detached single-family or attached townhomes (owner-occupied, or rentals with landlord's permission)
- Groups of manufactured or mobile homes (owner-occupied, or rentals with landlord's permission)
- Group homes or facilities providing housing and services for special needs or vulnerable populations, such as treatment and recovery

For the three primary investments of HIEE funds, DHCD has proposed and SAG supported a Fiscal Year 2022 allocation as shown in Table 3 below. DHCD will create programs with the projected $55 million revenue and use any additional revenue above these amounts to allocate to programs with the most demand.

Table 2.3 – Fiscal Year 2022 HIEE Investments

HIEE Component	**Fiscal Year '22 - % HIEE allocation**	**Projected revenue** *($55 m from Q2-Q4 2021 & Q1 2022 auctions)*
Weatherization Deferral Repair Program	30%	$16.5 m
Affordable and Special Needs Housing Program	60%	$33 m
Housing Energy Efficiency Partnerships Grants	10%	$5.5 m

2.3 HIEE Funding Contribution in Virginia's Affordable Housing Development Market

The HIEE funds represent a significant new dedicated revenue stream for improving affordable housing in Virginia. The Affordable and Special Needs Housing (ASNH) program and Weatherization Assistance Program (WAP) have combined annual budgets of over $50 million from federal and state sources. Virginia Housing's Low Income Housing Tax Credit (LIHTC) program currently generates $20-$25 million annually for affordable housing projects in Virginia. These programs also encourage significant additional leveraged funding.
In summary, HIEE funds are an important additional funding source for existing affordable housing programs that will provide flexibility to DHCD in helping thousands of low-income Virginians access more energy efficient and healthier homes.

SECTION 3 – DEPARTMENT OF CONSERVATION AND RECREATION

3.1 State Fiscal Year 2021– July 1, 2020 through June 30, 2021

During March and April of 2021, a project manager and administrative coordinator were hired to assist the Special Assistant to the Governor for Coastal Adaptation and Protection with the development of the Virginia Coastal Resilience Master Plan. The Master Plan details the Commonwealth's equity driven approach to coastal protection and adaptation and enhances coastal resilience, better protects key assets, and provides cost-effective strategies to conserve and enhance natural flood controls. Also in March, negotiations were finalized with Dewberry Engineers, Inc. for the development of the final Master Plan. The Plan includes a coastal flood hazard assessment, a risk and impact assessment of community resources, critical sector infrastructure and natural infrastructure, including identification of "hotspots" those areas most vulnerable to coastal flooding in the near term, development of a project database and project prioritization process, development of a funding source database – searchable and aligned to identify specific funding sources by project, development of a publicly accessible web application and viewer to host all of the above deliverables, and a final document. The project database will provide a list of locality-approved projects throughout the coastal region that will be shovel ready when funding is available.

The contract, valued at $2.8 million, is to be completed in two phases: Basic Services, described below, valued at $1.4 million, completed November 30, 2021, and Additional Services, valued at $1.2 million. Additional services anticipated include future condition modeling of fluvial and pluvial impacts, as well as other services as determined by the Commonwealth. In addition , the Commonwealth has added approximately $200,000 of additional work, including five additional four hour working meetings with PDC/RC's and Federal Installation partners (completed), and one working session with Virginia Tribes (pending), project ID and Capacity Building data collection, web application support and data hosting through November, 2022, and coastal flood hazard impact assessment through the year 2100. The contract Basic Services also include tracking and documentation tools as well as the following deliverables:

Task 1:

- Project coordination meeting with CRO/SACAP (24 meetings)
- Technical Advisory Committee Meetings Support and Minutes (7 meetings)
- Technical Advisory Subcommittee Meetings, Support and Minutes (49 meetings across 7 Subcommittees)

Task 2: Study Conceptual Model,

Task 3: Coastal Flood Hazard Framework, including Dynamic Future Condition Modeling Approach (Additional Services)

Task 4: Built and natural Infrastructure Risk Assessment
Including Data Gathering, Impact Assessment and Risk Summarization

Task 5: Adaptation Strategies and Prioritization
Including Prioritization Framework, Project inventory, Identification, Suitability Assessment, Impact Assessment Working Meetings with PDC/RC's

Task 6: Funding Analysis
Including Funding databases and Analysis and Funding Stream Alignments by Project

Task 7: Master Plan Document

Task 8: Project Database and GIS Web Service
Including Wireframe, Web Application, and Data Migration

Task 9: External Outreach and Public Engagement (60 total meetings):

- Coastal Planning District Commissions (8 meetings),
- Local Governments (8 meetings),
- Local Communities with emphasis on Underserved and Rural Communities (32 meetings),
- Local Businesses/Industries (2 meetings),
- Universities/Military (2 meetings),
- Key Stakeholder Interviews (8 meetings),
- Social Media, Outreach Media, Press/event tracking and content (25 content items)
- Build, Conduct, Analyze surveys of (A) General Public and (B) Local Practitioners (2 Surveys)

Throughout this process the Special Assistant to the Governor for Coastal Adaptation and Protection, the Virginia Coastal Resilience Master Plan Project Manager and the Virginia Coastal Resilience Master Plan Project Coordinator conducted, and continue to conduct multiple outreach, engagement, coordination and presentation sessions and working meetings explaining and seeking input on the Master Plan and process with a wide range of stakeholders, including State Agencies, PDC/RC Staff, Locality Staff, Non-Governmental organizations, Business and Community organizations, Community members, Civic Organizations, Federal Partners, Academia, and many others.

The Virginia Coastal Resilience Master Plan and Web Application may be viewed here: https://www.dcr.virginia.gov/crmp/

On June 4, 2021, DCR opened the first grant round of the Community Flood Preparedness Fund (CFPF) with a total of $18M in funding available under three categories; Capacity Building and Planning, Studies, and Projects. The CFPF requires that at least 25 percent of funds disbursed from the fund is provided to low-income geographic areas. Local governments and tribal organizations were able to submit applications through September 3, 2021. Applications under the "Projects" category required a DCR approved resilience plan prior to the acceptance of applications. The resilience plan is the locally developed roadmap to address recurrent and

repetitive flooding as localities seek funding through the CFPF.

On June 15, 2021, DCR conducted a technical assistance workshop to assist potential applicants to better understand the requirements of the CFPF grant program. The workshop and associated recording and Q&A is linked below.

- **June 15, 1-3 p.m.**

  View the recording.

- Read the **transcript of the recording** (PDF).
- Read the **chat log** (PDF).

3.2 State Fiscal Year 2022 through November 2021

Grant application reviews were conducted by DCR in consultation with the Secretary of Natural and Historic Resources and the Special Assistant to the Governor for Coastal Adaptation and Protection on September 21, 2021. First round awards were announced through the Governor's office in October 2021.

Using the same grant guidance and requirements, on August 5, 2021, DCR opened a second grant round of the CFPF with a total of $17M in funding available. This grant round closed for applications on November 5, 2021 and are now under review.

DCR conducted two additional technical assistance workshops in July and August 2021 to assist potential applicants to better understand the requirements of the CFPF grant program. The workshops and associated recordings and Q&As are linked below.

- **Aug. 13, 1-3 p.m.**

  View the recording.

  - Read the **transcript of the recording** (PDF).
  - Read the **chat log** (PDF).

- **July 15, 1-3 p.m.**

  View the recording.

  - Read the **transcript of the recording** (PDF).
  - Read the **chat log** (PDF).

The first grant round of the CFPF closed September 3, 2021. DCR received 32 applications with total project costs of more than $23 million. This total includes $16 million in requested CFPF funds.

Community Flood Preparedness Fund 2021 Grant Awards for the first round:

Eastern Branch of Elizabeth River Wetland and Floodplain Restoration | $3,000,000
City of Virginia Beach

McGuire and Chapel Drive Drainage Improvements Project | $1,100,000
City of Richmond

Norfolk Coastal Storm Risk Management Analysis | $900,000
City of Norfolk

Portsmouth's Data-Driven and Equity-Driven Resilience Strategy | $527,949
City of Portsmouth

Lake Whitehurst Watershed Study | $500,000
City of Norfolk

Plans and Capacity Building with Consultant Services | $387,500
Buchanan County

Oyster Plan - Capacity Building and Resilience Planning | $202,232
Northampton County

Resilient Hampton: Downton Hampton, Phoebus and Buckroe Beach | $158,681
City of Hampton

Moores Creek Watershed | $153,500
City of Charlottesville

Honor Park Resilience Park | $147,994
City of Hampton

Mill Point Living Shoreline | $126,498
City of Hampton

Resilient Stormwater Capacity and Green Streets Project | $115,200
City of Alexandria

Richmond Manchester and Shockoe Bottom Neighborhoods | $103,500
City of Richmond

Southern Chesapeake - Watershed 5 | $91,404
City of Chesapeake

Resilience Plan | $74,997
City of Chesapeake

Capacity Building and Planning | $68,024
City of Suffolk

Resilience Plan | $65,040
City of Winchester

The Impacts of Climate Change on Crop Planning and Production: An Agricultural Study of the Eastern Shore | $47,121
Accomack-Northampton Planning District Commission

Carlton Road Boat Ramp, Wake, Virginia - Design and Permitting | $26,400
Middle Peninsula Planning District Commission (Middlesex County)

A third RGGI auction occurred during September 2021 and provided an additional $23,781,288.82 in funding to the CFPF. A third grant round is currently under development. That application period will open in January 2022 and run for 90 days.

The fourth RGGI auction in December 2021 will provide sufficient funding to initiate loans by mid-2022. DCR and the Virginia Resource Authority (VRA) will soon begin meeting to develop loan guidelines, such as any requirements for collateral.

The Virginia Coastal Resilience Master Plan Phase One was completed on November 30th, on schedule, and released by Governor Ralph Northam on December 7th, 2021. The Public Announcement event was held in Hampton, Virginia. The Department of Conservation and Recreation also opened its Virginia Coastal Resilience Master Plan website and Web Application on December 7th, making the full impact assessment and project database available to the public. Coastal Flood Hazard layers are downloadable for use by localities and the public, and additional data layers are being made available for download in the future. The Project Database will be accessible to localities and identified users to continue to add projects and capacity building needs for further evaluation and funding consideration as additional risks are evaluated and analyzed in future iterations of the Master Plan.

The Special Assistant to the Governor, along with the VCRMP Project Manager and Project Coordinator are now coordinating with Stakeholders to determine and refine the Additional Services, with a focus on the Dynamic Future Condition Modeling, and fluvial and pluvial modeling. In addition, they are developing and Outreach and Engagement plan to continue through the Additional Services portion of the contract to facilitate a sustained public planning and input process.

The Virginia Coastal Resilience Master Plan and Web Application may be viewed here: https://www.dcr.virginia.gov/crmp/

SECTION 4 – DEPARTMENT OF ENERGY

4.1 Overview of Participation

Throughout 2021, Virginia Department of Energy ("Virginia Energy") staff participated in advisory discussions with DHCD relating to low-income energy efficiency programs, including programs for eligible housing developments. This included participation as an "Agency Partner" in meetings with the Housing Innovations in Energy Efficiency ("HIEE") Stakeholder Advisory Group, as well as direct discussions with DHCD staff on matters relating to program development, funding opportunities, and data analysis. Virginia Energy staff provided recommendations pertaining to how historically economically disadvantaged communities ("HEDCs") could be a component of the program and data analysis to ensure the program funds are benefitting disadvantaged communities. Virginia Energy staff will continue to serve as advisors to the program and are available for additional technical assistance upon request.

Attachment 5

Commonwealth of Virginia
Office of the Governor

Executive Order

NUMBER FIFTY SEVEN (2016)

DEVELOPMENT OF CARBON REDUCTION STRATEGIES FOR ELECTRIC POWER GENERATION FACILITIES

Part I – Importance of the Initiative

Though our coastal communities may be the first to witness the effects of climate change, the risks presented by increasingly fierce storms, severe flooding, and other extreme weather events are not confined to a single geographic area. Neither are their causes. The economic implications are significant, and we must do all we can to protect our critical military infrastructure, our ports, our homes, and our businesses. It is only by acting together with common purpose that the Commonwealth can effectively adapt and stave off the most severe consequences of climate change.

One key step forward is to continue with a strategic goal of reducing carbon emissions. Virginia has already made meaningful strides – between 2005 and 2014, Virginia reduced its carbon emissions from power plants by 21 percent. However, the electric sector is still responsible for approximately 30 percent of the carbon dioxide pollution in the Commonwealth. Moreover, electric companies are including carbon regulation projections in their long-term plans. The electric sector is changing rapidly through increasing reliance on low and zero carbon resources. As such, it is vital that the Commonwealth continue to facilitate and engage in a dialogue on carbon reduction methods while simultaneously creating a pathway for clean energy initiatives that will grow jobs and help diversify Virginia's economy.

Accordingly, by virtue of the authority vested in the Governor under Article V of the Constitution of Virginia and under the laws of the Commonwealth, I hereby direct the Secretary of Natural Resources to convene a Work Group, chaired by the Secretary, to study and recommend methods to reduce carbon emissions from electric power generation facilities. The Secretary shall receive input from interested stakeholders.

Such methods shall align with the Virginia Air Pollution Control Board's power to promulgate regulations abating, controlling and prohibiting air pollution throughout or in any part of the Commonwealth.

Part II – Scope and Guidance

In preparing their recommendations, the Secretary and the Work Group shall consider the following:

(1) the establishment of regulations for the reduction of carbon pollution from existing electric power generation facilities pursuant to existing authority under Virginia Code § 10.1-1300 *et seq.*;

(2) the carbon reduction requirements for existing electric power generation facilities established under § 111(d) of the federal Clean Air Act, which are currently stayed pending final disposition;

(3) the interaction between electric utilities and regional markets, including PJM Interconnection;

(4) the impact any reduction requirements place on the reliability of the electric system;

(5) the impact any reduction of carbon pollution may have on electric rates and electric bills;

(6) the impact of reducing carbon pollution on low income and vulnerable communities;

(7) the cost effectiveness of pollution reduction technologies that may be deployed;

(8) the economic development opportunities associated with deployment of new carbon reduction technologies;

(9) the implementation and administration of carbon reduction regulations; and

(10) flexibility in achieving the goals of any carbon reduction regulation.

The Secretary of Natural Resources shall complete her work, including the development of recommendations as to viable carbon reduction methods for the electric power generation facilities by April 30, 2017. The Secretary of Natural Resources shall provide a report on the recommendations to the Governor by May 31, 2017.

Effective Date of the Executive Order

This Executive Order shall be effective upon its signing and shall remain in full force and effect for one year after its signing unless amended or rescinded by further executive order.

Given under my hand and under the Seal of the Commonwealth of Virginia this 28th Day of June, 2016.

Terence R. McAuliffe, Governor

Attest:

Kelly Thomasson, Secretary of the Commonwealth

Attachment 6

COMMONWEALTH of VIRGINIA

GOVERNOR TERENCE R. MCAULIFFE'S EXECUTIVE ORDER 57 WORK GROUP

REPORT AND FINAL RECOMMENDATIONS TO THE GOVERNOR

May 12, 2017

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APPENDIX A: Text of Executive Order 57

APPENDIX B: Executive Order 57 Work Group Agendas

I. Introduction

Climate change along with associated sea-level rise and increasingly volatile weather patterns pose potentially devastating risk to Virginia. According to data compiled by the Georgetown Climate Center and Old Dominion University's Mitigation and Adaptation Research Institute, the Commonwealth has already seen a 33 percent increase in heavy rainstorms and snowstorms in the last sixty years, as well as an 11 percent increase in precipitation from the largest storms.[1] The same report found that as many as 400,000 Virginia homes are at risk of damage from increased storm surges. The researchers projected that rebuilding Virginia's at-risk residential property could cost $92 billion. Home loss disproportionately affects low-income homeowners who often lack the insurance or capital to relocate or rebuild without jeopardizing their overall financial security.

Climate change also has the potential to endanger the Commonwealth's agricultural sector, particularly small, family-owned farms without the resources to implement expensive site-specific adaptation strategies. Half of Virginia's counties face increased risk of water shortages by 2050 as the result of climate-related shifts in precipitation and weather.[2] Currently, agriculture is Virginia's largest industry, supporting almost 311,000 jobs with an annual economic impact of $52 billion.[3] Other business sectors are similarly feeling the impacts of climate change as warmer temperatures affect worker productivity and the health of the workforce.[4]

In addition to the environmental and economic consequences of climate change, carbon emissions also pose a significant risk to human health. According to data from the United States Centers for Disease Control and Prevention, the burning of fossil fuels has resulted in negative impacts to air and water quality and been linked to increased incidence of asthma and cardiovascular disease.[5] Across the United States, warmer temperatures have been linked to increased ground-level ozone[6] and more frequent and sustained wildfires,[7] a major contributor to

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[1] Georgetown Climate Center and Old Dominion University Mitigation and Adaptation Research Institute, *Understanding Virginia's Vulnerability to Climate Change*, February 17, 2017, *available at* http://www.georgetownclimate.org/files/report/understanding-virginias-vulnerability-to-climate-change.pdf (last accessed May 9, 2017).
[2] *See id*.
[3] Virginia Department of Agriculture and Consumer Services, *Virginia Agriculture Facts & Figures*, *available at* http://www.vdacs.virginia.gov/markets-and-finance-agriculture-facts-and-figures.shtml (last accessed May 9, 2017).
[4] U.S. Global Change Research Program. *Impacts of Climate Change on Human Health in the United States: A Scientific Assessment,* April 2016, *available at* https://health2016.globalchange.gov/ (last accessed May 9, 2017).
[5] Centers for Disease Control and Prevention, *A Human Health Perspective on Climate Change*, https://www.cdc.gov/climatechange/pubs/hhcc_final_508.pdf (last accessed May 9, 2017).
[6] Pfister, G. G., S. Walters, J.-F. Lamarque, J. Fast, M. C. Barth, J. Wong, J. Done, G. Holland, and C. L. Bruyère, Journal of Geophysical Research: Atmospheres, *Projections of future summertime ozone over the U.S.*, *available at* http://onlinelibrary.wiley.com/doi/10.1002/2013JD020932/abstract (last accessed May 9, 2017).

particulate matter pollution harmful to public health. Evidence from the Virginia Department of Health shows increased incidences of West Nile virus and Lyme disease,[8] an indication that recent environmental shifts may have improved survival rates for disease vectors like ticks and mosquitos.

The impacts of climate change are also causing ocean warming and ice-sheet loss, resulting in potential sea level rise of more than five feet in Virginia by the turn of the century.[9] Because of its low-lying elevation, natural geography, and high rate of land subsidence, Hampton Roads is consistently ranked as the second most vulnerable region in the country at risk from rising seas, a clear and accelerating result of climate change.[10] According to analysis by Risk Management Solutions, the Virginia Beach-Norfolk Metropolitan Statistical Area ranks 10th in the world for assets at risk of flooding as the result of relative sea level rise.[11] The Hampton Roads Planning District Commission estimates that a conservative three foot rise in sea level would cover nearly 900 miles of roads in the region, costing as much as $87 billion.[12] Naval Station Norfolk, the world's largest naval base, has replaced four World War II-era piers to compensate for higher seas and plans to build eight more, at a cost of more than $100 million per pier.[13]

Given the challenges associated with climate change and the need for solutions, Virginia is uniquely positioned to become a leader in the international efforts to reduce carbon dioxide emissions and stave off the most dramatic consequences of climate change. While carbon dioxide emissions from Virginia's electric generating units have fallen by 21 percent between 2005 and 2014, they still account for approximately 30 percent of the state's overall carbon dioxide emissions. Investments have accelerated since 2014, but the Commonwealth has tremendous potential to build on this growth and achieve even greater carbon emission reductions through additional investments in clean energy technologies.

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[7] A. L. Westerling, H. G. Hidalgo, D. R. Cayan, T. W. Swetnam, Science Magazine, *Warming and Earlier Spring Increase Western U.S. Forest Wildfire Activity*, *available at* http://science.sciencemag.org/content/313/5789/940.full (last accessed May 9, 2017).

[8] Virginia Department of Health, *Ten-Year Trend in Number of Reported Cases of Reportable Diseases in Virginia, 2006-2015*, *available at* http://www.vdh.virginia.gov/content/uploads/sites/13/2016/03/table2a_trend2015.pdf (last accessed May 9, 2017).

[9] Virginia Institute of Marine Science, *Sea Level Rise Scenarios*, *available at* http://www.vims.edu/newsandevents/topstories/slr_scenarios.php (last accessed May 9, 2017).

[10] Deconcini, C. and Tompkins, F., World Resources Institute, *Sea-level Rise and its Impact on Virginia*, *available at* https://www.wri.org/sites/default/files/wri_factsheet_virginia_final.pdf (last accessed May 9, 2017).

[11] Nicholls, R. J., Hanson, S., Herweijer, C., Patmore, N., Hallegatte, S., Corfee-Morlot, J., Château, J., & MuirWood, R., Organisation for Economic Co-operation and Development, *Ranking Port Cities with High Exposure and Vulnerability to Climate Extremes*, *available at* http://www.oecd-ilibrary.org/environment/ranking-port-cities-with-high-exposure-and-vulnerability-to-climate-extremes_011766488208 (last accessed May 9, 2017).

[12] Hampton Roads Planning District Commission, *Climate Change in Hampton Roads, Phase III: Sea Level Rise in Hampton Roads, Virginia*, *available at* http://www.hrpdcva.gov/library/view/230/climate-change-in-hampton-roads:phase-iii-sea-level-rise-in-hampton-roads-july-2012 (last accessed May 9, 2017).

[13] Evan Leghmann, E&E News, *Inside One Naval Base's Battle with Sea-Level Rise*, Oct. 27, 2016, *available at* https://www.eenews.net/stories/1060044863 (last accessed May 9, 2017).

Today, Virginia has more than 1,800 megawatts (MW) of solar currently in service or under development.[14] In the last year alone, the number of solar jobs in Virginia has increased by 65 percent, from 1,963 to 3,236.[15] Virginia's solar job market is the 9th-fastest-growing solar jobs market in the nation.[16] The Commonwealth is already home to over 75,000 energy efficiency workers.[17] Energy efficiency business revenue in Virginia has increased from $300 million in 2013 to $1.5 billion in 2016, a five-fold increase.[18] The continued growth of clean energy investment in the Commonwealth has the potential to bring about long-term sustainable economic development while also mitigating the impacts of climate change through reduced carbon dioxide emissions.

With these two principals in mind – the enormity of climate change impacts and the potential for clean energy industry growth – Governor McAuliffe signed Executive Order 57 ("EO 57") on June 28, 2016. When the Governor issued EO 57, he recognized that the Commonwealth must continue to facilitate and engage in a dialogue on carbon reduction methods while simultaneously creating a pathway for clean energy initiatives that will grow jobs and help diversify Virginia's economy. Through the Executive Order, Governor McAuliffe directed the Virginia Secretary of Natural Resources, Molly Ward, to convene an EO 57 Work Group ("Work Group") to study these issues and recommend methods to reduce carbon emissions from the electric sector in Virginia. The focus of the Work Group was to evaluate options under the Governor's existing authority while simultaneously creating more clean energy jobs.

In addition to Secretary Ward, the Work Group was comprised of Secretary of Commerce and Trade Todd Haymore, Virginia Department of Environmental Quality Director David Paylor, Virginia Department of Mines, Minerals and Energy Director John Warren, and Deputy Attorney General for Commerce, Environment, and Technology John Daniel. Through a robust stakeholder engagement process, the Work Group received presentations and feedback from a variety of perspectives including electric utilities, clean energy businesses, industrial manufacturing, academic institutions, environmental organizations, and other interested stakeholders. This report is the result of the efforts of the Work Group.

The full text of Executive Order 57 is provided in Appendix A and the complete agendas for all of the Work Group meetings are provided in Appendix B of this report.

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[14] Department of Mines Minerals and Energy, Solar Tracking Data, Updated May 5, 2017.
[15] The Solar Foundation, *National Solar Jobs Census 2016*, *available at* http://www.thesolarfoundation.org/national/ (last accessed May 9, 2017).
[16] *See id*.
[17] U.S. Department of Energy, *2017 US Energy and Employment Report*, *available at* https://energy.gov/downloads/2017-us-energy-and-employment-report (last accessed May 9, 2017).
[18] The Virginia Energy Efficiency Council, *Why Energy Efficiency is a Smart Investment in Virginia, available at* http://vaeec.org/resources/data/ (last accessed May 15, 2017).

II. Process

EO 57 outlined a process for the Governor, through the Secretary of Natural Resources, to receive recommendations from the public to further reduce the Commonwealth's carbon emissions and grow the clean energy economy under existing state authority. This process ensured that the Work Group would have the necessary public input to develop recommendations and submit a report to the Governor by the May 31, 2017 deadline stipulated in the Executive Order.

The process consisted of six monthly meetings that began on August 31, 2016 and ended on February 28, 2017. Each public meeting lasted between two and three hours, and the meetings consisted of presentations from members of the public. The presentations were voluntary, and all members of the public were invited to send suggested topics and presenter information to the Secretary of Natural Resources' office. In total, the Work Group received more than forty presentations. Each presentation was made publicly available on the Secretary of Natural Resources' website.[19]

In addition to the public meetings, the Work Group also facilitated a three month written public comment period that opened on February 1, 2017 and closed on April 30, 2017. Members of the public were invited to submit comments either electronically or in hard copy to the Office of the Secretary of Natural Resources. In total, the Work Group received over 8,000 written comments.

III. Recommendations

The recommendations set forth in this report are drawn from the information developed and understanding gained through the public meetings and the public comment process. The Work Group synthesized the many presentations and comment topics down to the five recommendations set forth below. This list does not attempt to include every recommendation that was provided to the Work Group, but it covers the broad categories of recommendations for the Governor's consideration.

1.) Promulgate regulations to limit carbon dioxide emissions

The Work Group received a number of presentations and written comments from stakeholders advocating for a regulation to limit carbon dioxide emissions from power plants. These comments included recommendations that the Commonwealth join or participate in the Regional Greenhouse Gas Initiative ("RGGI") or another regional trading program, that a price be put on carbon, and that Virginia strive to reduce its greenhouse gas emissions by 30 to 40 percent by the year 2030.

[19] *See* Office of the Secretary of Natural Resources Website*, available at* http://naturalresources.virginia.gov/initiatives/eo-57/.

The Work Group received information on both ratepayer impacts and potential job creation opportunities associated with a regulation to limit carbon emissions. Advanced Energy Economy modeled carbon reduction targets similar to those in the federal Clean Power Plan that would be achieved through implementation of power generation fleet changes already planned by utilities along with the addition of renewable energy and energy efficiency measures. They found that these actions would result in 54,231 cumulative additional job years by 2030 and, if Virginia reduced its imports while applying the same carbon reduction actions, we could see the number of cumulative additional job-years double to more than 120,000. The Natural Resources Defense Council, which advocated for a 30 percent reduction target by the year 2030 (i.e., 30x30), also performed utility-sector modeling. They found that if the target included 20 percent in-state renewable generation and 1.5 percent annual energy efficiency savings, Virginia customer electric bills would decrease by almost $100 per year.

The business community also weighed in on the establishment of carbon dioxide regulations. Mars, Nestle, and Unilever filed joint comments noting that "an annual emissions reduction cap or clean energy standard are models that have been effective in other states' efforts to foster clean energy development." These companies stated that while they do not support one particular policy over another, they "believe that such policies will create market certainty and drive private-sector investments."

The Business Council for Sustainable Energy stated that "[s]uccessful reduction of Virginia's carbon emissions will require embracing the full portfolio of clean energy and energy efficiency technologies, products, and services." Dominion Resources filed comments stating that they "have confidence the Commonwealth can devise a forward-looking plan ensuring the continued decline in carbon emissions that is compatible with promoting a growing economy and keeping Virginia the most attractive state for new businesses." In addition, Dominion stated, "a rate-based approach or a mass-based limit on existing sources is the most accurate way to stimulate economic growth and job creation while achieving measurable carbon emission reductions."

The University of Virginia's Environmental and Regulatory Law Clinic and the Southern Environmental Law Center provided information on the legal justification for regulatory action. Both presentations focused on the current authority of the State Air Pollution Control Board ("Board") and the Department of Environmental Quality under Virginia Code § 10.1-1300 *et seq*. Each concluded that the Board has authority to regulate carbon dioxide from electric power generation facilities. This has since been confirmed by Attorney General Mark Herring in an official opinion dated May 12, 2017.

In short, there was tremendous public interest in this particular recommendation. Although many stakeholders provided feedback focused on specific in-state targets (such as 30x30), the Work Group believes that it is important and necessary that Virginia work through a

regional model, like the established and successful RGGI, in order to both achieve lower compliance costs and address the interstate nature of the electric grid.

The Work Group recommends that the Governor consider taking action via a regulatory process to establish a "trading-ready" carbon emissions reduction program for fossil fuel fired electric generating facilities that will enable participation in a broader, established multi-state carbon market.

2.) Update state building codes to reflect current technology and standards

Buildings account for approximately 70 percent of America's electricity consumption and more than 40 percent of total national energy usage annually, producing 39 percent of the United States' overall carbon emissions.[20] Inefficiency in building design was a major source of stakeholder concern, and a number of presenters and written comments focused on the need to strengthen Virginia's building codes. Some commenters recommended that Virginia adopt the 2015 International Energy Conservation Code (IECC) with no alterations while others recommended updating to the 2012 IECC without amendments.

Currently, Virginia's building code embraces the standards from the 2012 IECC for commercial properties and the 2009 equivalent for residential structures. Arlington County recommended adoption of the 2015 IECC with no alterations, and noted that "Virginia homeowners would save $2.5 billion between 2010-2040 and avoid nearly 16 million metric tons of carbon emissions." The Southeast Energy Efficiency Alliance also recommended that Virginia update its building codes to the 2015 IECC, and noted that "Virginia could achieve annual carbon savings of 1.21 million metric tons CO2 by 2030, and cumulative savings of 15.66 million metric tons CO2 from 2010 to 2030." The Virginia Energy Efficiency Council and Local Energy Alliance Program similarly recommended updating the building codes to the 2015 IECC. The Virginia Poverty Law Center recommended that Virginia update the building codes to the 2012 IECC, but that Virginia develop a plan to adopt the 2018 updates when they are released.

The Work Group also received information evaluating compliance with Virginia's current building codes. Recent testing in both Charlottesville and McLean, presented by the Virginia Energy Efficiency Council and the Local Energy Alliance Program, shows that a significant portion of the Commonwealth's homes do not meet established standards for air-tightness or ductwork. The U.S. Department of Energy (DOE) is conducting a statewide research field study investigating energy code implementation in residential buildings in Virginia. This study will provide valuable Virginia-specific data on energy code compliance as well as insight into market-driven efficiency decisions of homebuilders.

[20]Presentation by Virginia Energy Efficiency Council and Local Energy Alliance Program, *The Role of Building Energy Codes in a Carbon Reduction Strategy for Virginia*, *available at* http://naturalresources.virginia.gov/media/8635/4-vaeec.pdf.

The Virginia Board of Housing and Community Development (BHCD) is currently in the process of updating the Commonwealth's Uniform State building codes (USBC). This spring, BHCD began accepting amendments to the draft code and stakeholder workgroups began meeting. By November of 2017, BHCD will vote on the final State Building Codes.

The Work Group recommends that BHCD update the commercial building codes to reflect the 2015 IECC and that the residential building codes be consistent with current technology and be more reflective of the 2015 IECC. In addition, the Department of Mines, Minerals and Energy should participate in data collection efforts, including the previously-mentioned DOE energy code field study, to better inform the building code process and to provide data and best practices for implementation.

3.) Improve access to clean energy resources like solar, wind, and energy efficiency

Stakeholders from a variety of constituencies across the Commonwealth presented or filed comments on the need to further increase deployment of clean energy resources. However, the policy recommendations that would achieve such a result varied. Some presenters recommended adoption of a mandatory Renewable Portfolio Standard (RPS) while others focused on market opportunities and customer choice.

A number of presenters focused on recommendations regarding the adoption of a mandatory RPS. Virginia's Renewable Energy Portfolio goal was created via legislation in 2007 as part of the re-regulation of the Commonwealth's electrical industry. The goal was set to incrementally increase until 2025, at which point it would level off to 15 percent of electricity sold by a utility. Two years after adoption of this preliminary goal, legislation was passed allowing research and development expenses to be counted towards up to 20 percent of the goal. Further legislative modifications were made in 2013 to remove the incentive structure supporting utility compliance. While there are merits to the RPS, a mandatory RPS would require legislation, and the Work Group has aimed its focus on recommendations that could be implemented through the Governor's executive authority.

The Governor has used his executive authority to show state leadership in powering state operations with renewable energy. In 2014, the Governor announced a goal of getting 8 percent of state government's electricity from renewable sources within three years. The Commonwealth is moving toward achieving this goal through partnerships with the U.S. Navy and the University of Virginia. However, some presenters noted that Virginia should expand on this lead-by-example model by meeting stated energy reduction targets and expanding the state renewable procurement target.

Another set of recommendations addressed the need to grow market opportunities and increase customer choice, both at the business and residential levels. Mars, Nestle, and Unilever recommended that the Governor develop an "explicit legal framework to allow companies to enter into contracts with non-utility energy providers through third-party financing or offering

utility-administered, cost-of-service-based renewable energy tariffs for large buyers." E2 recommended that the Governor convene a task force including DMME, the State Corporation Commission, the Department of Environmental Quality, the Virginia Economic Development Partnership, Dominion, and Appalachian Power to discuss corporate renewable procurement needs and how to meet them. Ceres noted that corporate procurement targets increasingly focus on achieving 100 percent renewable energy and companies will factor this into site selection when considering investments in new facilities or expansion of existing operations.

A number of activities have occurred in the General Assembly to drive increased solar development. Solar industry and utility representatives met over fifty times in 2016 to break the legislative impasse over needed changes to the existing legislative framework governing solar generation in Virginia. This group (the "Solar Group"), facilitated by the Virginia Center for Consensus Building at VCU, crafted three pieces of legislation that passed the General Assembly unanimously in 2017 and were signed into law by the Governor. Senate Bill 1393 created a pilot program for community solar projects administered by utilities. Senate Bill 1394 and House Bill 2303 enacted an additional option for agricultural customers with solar installations. Senate Bill 1395 opened the streamlined Permit by Rule process for regulatory approval to certain projects not previously eligible. The EO 57 Work Group received recommendations to tackle additional solar deployment access issues. Building on the trust and respect that was established in 2016, the Solar Group could tackle even more complex issues in 2017 with more outreach to additional stakeholders.

The Work Group recommends that the Governor update Virginia's current renewable energy procurement target and work with the Solar Group to develop a comprehensive plan to increase corporate access to renewable energy as an economic development tool.

4.) Develop an energy efficiency accounting and registry tool

The Work Group received many presentations focused on the fact that Virginia faces challenges in the effort to improve and increase energy efficiency. Many other states are already in the process of implementing energy efficiency programs that are much more expansive than those in Virginia. In addition to recommendations on specific energy efficiency deployment mechanisms, the Work Group also received a presentation from E4TheFuture on the National Energy Efficiency Registry ("NEER").

This presentation noted that many regulatory systems and their supporting computer infrastructure have been developed independently at the state level, making it difficult to accurately track and compare results across state lines. To remedy this problem, the Tennessee Department of Environment & Conservation has partnered with the U.S. Department of Energy, the National Association of State Energy Officials, the Climate Registry, and agencies from Michigan, Minnesota, Oregon, and Pennsylvania to create the NEER. The registry, currently

under development, is intended to serve as a software platform for credibly evaluating the benefits of energy efficiency projects.

By providing a consistent framework for measuring and assessing energy efficiency initiatives, the registry could help states apply efficiency savings to their self-selected energy goals as well as existing or future federal or state regulation. In addition, NEER will use best practices in data management, reporting, and registry design, to improve data collection and management efficiency and, where possible, automate processes. Increased transparency could allow both private and public sector entities to see validated cost savings that can be achieved through improved efficiency, thus encouraging increased investments in conservation.

The Work Group recommends that the Department of Mines, Minerals and Energy investigate the NEER model and evaluate whether the registry could be a starting point for an energy efficiency accounting and trading mechanism conceptually similar to the currently used Renewable Energy Certificate.

5.) Establish a statewide Environmental Justice Advisory Council

An important element of the Executive Order 57 process, which was spelled out in the text of the order itself, is to make a particular effort to ensure that all people and perspectives have a voice in environmental discussions. This concept, known as environmental justice, is defined as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental law, regulations, and policies."[21]

Some environmental issues can be compounded or concentrated as the result of sociological factors. Low-income communities at risk from sea level rise often lack the resources to adequately improve resiliency and can suffer more sustained consequences as the result of personal property loss and damage. Virginia's power plants are disproportionately located in areas with high concentrations of poverty and people of color. Many of the most severe health consequences arising from coal-fired electrical generation are localized in nature, so this distribution unfairly burdens already disadvantaged communities with increased health problems and accompanying costs.

The Virginia Environmental Justice Collaborative proposed the creation of a statewide Environmental Justice Advisory Council ("EJAC"). Pursuant to this recommendation, the EJAC would serve as a sustained conduit for conversations about environmental justice and underserved communities.

The Work Group recommends that the Governor convene an EJAC consisting of appointed representatives to communicate directly with the Secretary of Natural Resources, the

[21]U.S. Environmental Protection Agency, *Learn About Environmental Justice*, *available at* https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.

Secretary of Commerce and Trade, the Secretary of Health and Human Resources, the Secretary of Public Safety and Homeland Security, and the Commission on Local Government. The EJAC should provide a forum for sharing information and making recommendations to policy makers to help ensure fair treatment and meaningful involvement by all people with respect to policy decisions that impact the environment and health of local communities.

IV. Conclusion

Climate change is among the most pressing issues facing humanity, but it is not insurmountable. While no single solution exists, the recommendations in this report offer attainable strategies that could be performed under the Governor's existing executive authority. These recommendations are aimed at both reducing carbon dioxide emissions from the electrical generation sector and driving economic growth from the clean energy sector. While Virginia cannot solve the problem of climate change alone, we can take important and necessary steps at the state level to protect our citizens from the most extreme impacts and create meaningful opportunities to grow the clean energy sector.

Appendix A:

Text of Executive Order 57

Commonwealth of Virginia
Office of the Governor

Executive Order

NUMBER FIFTY SEVEN (2016)

DEVELOPMENT OF CARBON REDUCTION STRATEGIES FOR ELECTRIC POWER GENERATION FACILITIES

Part I – Importance of the Initiative

Though our coastal communities may be the first to witness the effects of climate change, the risks presented by increasingly fierce storms, severe flooding, and other extreme weather events are not confined to a single geographic area. Neither are their causes. The economic implications are significant, and we must do all we can to protect our critical military infrastructure, our ports, our homes, and our businesses. It is only by acting together with common purpose that the Commonwealth can effectively adapt and stave off the most severe consequences of climate change.

One key step forward is to continue with a strategic goal of reducing carbon emissions. Virginia has already made meaningful strides – between 2005 and 2014, Virginia reduced its carbon emissions from power plants by 21 percent. However, the electric sector is still responsible for approximately 30 percent of the carbon dioxide pollution in the Commonwealth. Moreover, electric companies are including carbon regulation projections in their long-term plans. The electric sector is changing rapidly through increasing reliance on low and zero carbon resources. As such, it is vital that the Commonwealth continue to facilitate and engage in a dialogue on carbon reduction methods while simultaneously creating a pathway for clean energy initiatives that will grow jobs and help diversify Virginia's economy.

Accordingly, by virtue of the authority vested in the Governor under Article V of the Constitution of Virginia and under the laws of the Commonwealth, I hereby direct the Secretary of Natural Resources to convene a Work Group, chaired by the Secretary, to study and recommend methods to reduce carbon emissions from electric power generation facilities. The Secretary shall receive input from interested stakeholders.

Such methods shall align with the Virginia Air Pollution Control Board's power to promulgate regulations abating, controlling and prohibiting air pollution throughout or in any part of the Commonwealth.

Part II – Scope and Guidance

In preparing their recommendations, the Secretary and the Work Group shall consider the following:

(1) the establishment of regulations for the reduction of carbon pollution from existing electric power generation facilities pursuant to existing authority under Virginia Code § 10.1-1300 *et seq.;*

(2) the carbon reduction requirements for existing electric power generation facilities established under § 11l(d) of the federal Clean Air Act, which are currently stayed pending final disposition;

(3) the interaction between electric utilities and regional markets, including PJM Interconnection;

(4) the impact any reduction requirements place on the reliability of the electric system;

(5) the impact any reduction of carbon pollution may have on electric rates and electric bills;

(6) the impact of reducing carbon pollution on low income and vulnerable communities;

(7) the cost effectiveness of pollution reduction technologies that may be deployed;

(8) the economic development opportunities associated with deployment of new carbon reduction technologies;

(9) the implementation and administration of carbon reduction regulations; and

(10) flexibility in achieving the goals of any carbon reduction regulation.

The Secretary of Natural Resources shall complete her work, including the development of recommendations as to viable carbon reduction methods for the electric power generation facilities by April 30, 2017. The Secretary of Natural Resources shall provide a report on the recommendations to the Governor by May 31, 2017.

Effective Date of the Executive Order

This Executive Order shall be effective upon its signing and shall remain in full force and effect for one year after its signing unless amended or rescinded by further executive order.

Given under my hand and under the Seal of the Commonwealth of Virginia this 28th Day of June, 2016.

_____

Terence R. McAuliffe, Governor

Attest:

_____

Kelly Thomasson, Secretary of the Commonwealth

Appendix B:

Executive Order 57
Work Group Agendas

Executive Order 57 Work Group Meeting

August 31, 2016
1:00pm – 4:00pm
Patrick Henry Building, West Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome and Overview of Work Group Structure – Molly Ward, Secretary of Natural Resources

II. Presentation on Virginia's Carbon Reduction Efforts – Mike Dowd, Virginia Department of Environmental Quality

III. Presentation on the Legal Status of Carbon Reduction Rules – Matt Gooch, Virginia Office of the Attorney General

IV. Presentation on Supportive Research Regarding Climate Impacts – Emily Steinhilber and Molly Mitchell, Center for Recurrent Flooding Resiliency

V. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Maurice Jones, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

October 6, 2016
1:00pm – 4:00pm
Patrick Henry Building, East Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

a. PJM Interconnection, LLC

b. Tenaska

c. Advanced Energy Economy

d. Business Council for Sustainable Energy

e. Virginia League of Conservation Voters

f. Faith Alliance for Climate Solutions

g. Warrenton Climate Change Group

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

October 31, 2016
1:00pm – 4:00pm
Patrick Henry Building, East Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

a. American Council for an Energy Efficient Economy

b. Oil Change International

c. Alliance for Industrial Efficiency

d. Sierra Club

e. Virginia Housing Alliance

f. National Green Fuels

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

For those unable to attend in person, we have arranged a webcast using the following link: https://attendee.gotowebinar.com/register/6736447537171170050

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

December 1, 2016
1:00pm – 4:00pm
Patrick Henry Building, West Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

a. EnerNOC

b. Covanta

c. WestRock

d. Third Party Delivered Energy Efficiency Coalition

e. UVA School of Law's Environmental and Regulatory Law Clinic

f. Birchwood Power

g. Virginia Poverty Law Center

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

For those unable to attend in person, we have arranged a webcast using the following link: https://attendee.gotowebinar.com/register/5842017918223385090

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

January 10, 2017
1:00pm – 4:00pm
Patrick Henry Building, West Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

   a. E2

   b. Appalachian Voices

   c. Southeastern Wind Coalition

   d. Virginia Energy Efficiency Council

   e. American Lung Association

   f. Southeast Energy Efficiency Alliance

   g. ACN Energy Solutions

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

For those unable to attend in person, we have arranged a webcast using the following link: https://attendee.gotowebinar.com/register/5975119298986349057

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

February 28, 2017
1:00pm – 4:00pm
Patrick Henry Building, West Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

a. Ceres

b. Gerdau Long Steel North America

c. Virginia Environmental Justice Collective

d. E4TheFuture

e. Dominion

f. Southern Environmental Law Center

g. American Petroleum Institute

h. Verde Sources

i. Virginia Nuclear Energy Consortium

j. Natural Resources Defense Council

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

For those unable to attend in person, we have arranged a webcast using the following link: https://attendee.gotowebinar.com/register/6504634204203803393

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Attachment 7

COMMONWEALTH of VIRGINIA

Executive Department

Executive Directive 11 (2017)

REDUCING CARBON DIOXIDE EMISSIONS FROM ELECTRIC POWER FACILITIES AND GROWING VIRGINIA'S CLEAN ENERGY ECONOMY

There is no denying the science and the real-world evidence that climate change threatens the Commonwealth of Virginia, from our homes and businesses to our critical military installations and ports. Rising storm surges and flooding could impact as many as 420,000 properties along Virginia's coast that would require $92 billion of reconstruction costs.

The challenges and costs of bolstering resilience and minimizing risk are too great for any locality to bear alone. While the impacts are significant, there are technologies in the clean energy sector that could help mitigate these impacts while simultaneously creating jobs in twenty-first century industries. The number of solar jobs in Virginia has grown by 65 percent in the last year alone, and Virginia is now the ninth fastest growing solar jobs market in the country. Revenue for energy efficiency businesses in Virginia has increased from $300 million in 2014 to $1.5 billion in 2016. Through state leadership, Virginia can face the threats of climate change head on and do so in a way that makes clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio.

With these considerations in mind, I issued Executive Order 57 (EO 57) on June 28, 2016. Under EO 57, I directed the Secretary of Natural Resources to convene a work group to study and recommend methods to reduce carbon dioxide emissions from electric power facilities and grow the clean energy economy within existing state authority. The group consisted of the Secretary of Natural Resources, the Secretary of Commerce and Trade, the Director of the Virginia Department of Environmental Quality, the Director of the Virginia Department of

Mines, Minerals and Energy, and the Deputy Attorney General for Commerce, Environment, and Technology. This group facilitated extensive stakeholder engagement over the last year, including six in-person meetings and a three month public comment period, before compiling the recommendations and submitting a final report to me on May 12, 2017.

Among the most significant recommendations from the group is the need to develop regulations limiting the total amount of carbon dioxide emitted from electric power facilities. Given the nature of the climate change threat and the promise of clean energy solutions, I agree with this recommendation.

Accordingly, pursuant to the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10.1-1300, *et seq.* and Virginia Code § 2.2-4000, *et seq.*:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that:

    a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and

    b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10.1-1308.

Effective Date

This Executive Directive shall be effective upon its signing and shall remain in force and effect unless amended or rescinded by further executive order or directive.

Given under my hand and under the Seal of the Commonwealth of Virginia, this 16th day of May, 2017.

Terence R. McAuliffe, Governor

Attest:

Kelly Thomasson, Secretary of the Commonwealth

Attachment 8

townhall.virginia.gov

Notice of Intended Regulatory Action (NOIRA)
Agency Background Document

Agency name	State Air Pollution Control Board
Virginia Administrative Code (VAC) citation(s)	Part VII, 9VAC5-140
Regulation title(s)	Regulation for Emissions Trading
Action title	Establish a new regulation to reduce and cap carbon dioxide (CO_2) from fossil fuel fired electric power generating facilities by means of an interstate trading program (Revision C17)
Date this document prepared	May 22, 2017

This information is required for executive branch review and the Virginia Registrar of Regulations, pursuant to the Virginia Administrative Process Act (APA), Executive Orders 17 (2014) and 58 (1999), and the *Virginia Register Form, Style, and Procedure Manual.*

Subject matter and intent

Please describe briefly the subject matter, intent, and goals of the planned regulatory action. Also include a brief explanation of the need for and the goals of the new or amended regulation.

The purpose of the proposed action is to develop a regulation, in accordance with Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from Electric Power Facilities and Growing Virginia's Clean Energy Economy," that (i) ensures that Virginia is trading-ready to allow for the use of market-based mechanisms and the trading of carbon dioxide (CO_2) allowances through a multi-state trading program, and (ii) establishes abatement mechanisms that provide for a corresponding level of stringency to CO_2 limits imposed in other states with such limits.

Acronyms and Definitions

Please define all acronyms used in the Agency Background Document. Also, please define any technical terms that are used in the document that are not also defined in the "Definition" section of the regulations.

CO_2 - carbon dioxide

RGGI - Regional Greenhouse Gas Initiative

Legal basis

Please identify (1) the agency (includes any type of promulgating entity) and (2) the state and/or federal legal authority for the proposed regulatory action, including the most relevant citations to the Code of Virginia or General Assembly chapter number(s), if applicable. Your citation should include a specific provision, if any, authorizing the promulgating entity to regulate this specific subject or program, as well as a reference to the agency's overall regulatory authority.

Statutory Authority

Section 10.1-1308 of the Virginia Air Pollution Control Law (Title 10.1, Chapter 13 of the Code of Virginia) authorizes the State Air Pollution Control Board to promulgate regulations abating, controlling and prohibiting air pollution in order to protect public health and welfare.

Promulgating Entity

The promulgating entity for this regulation is the State Air Pollution Control Board.

State Requirements

Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia's Clean Energy Economy," directs the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10.1-1300 et seq., and Virginia Code § 2.2-4000, et seq.:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit CO_2 from electric power facilities that:

a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of CO_2 allowances through a multi-state trading program; and

b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on CO_2 emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10.1-1308.

Purpose

Please describe the specific reasons why the agency has determined that the proposed regulatory action is essential to protect the health, safety, or welfare of citizens. In addition, please explain any potential issues that may need to be addressed as the regulation is developed.

Governor McAuliffe's Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia's Clean Energy Economy" states:

There is no denying the science and the real-world evidence that climate change threatens the Commonwealth of Virginia, from our homes and businesses to our critical military installations and ports. Rising storm surges and flooding could impact as many as 420,000 properties along Virginia's coast that would require $92 billion of reconstruction costs.

The challenges and costs of bolstering resilience and minimizing risk are too great for any locality to bear alone. While the impacts are significant, there are technologies in the clean energy sector that could help mitigate these impacts while simultaneously creating jobs in twenty-first century industries. The number of solar jobs in Virginia has grown by 65 percent in the last year alone, and Virginia is now the ninth fastest growing solar jobs market in the country. Revenue for clean energy businesses in Virginia has increased from $300 million in 2014 to $1.5 billion in 2016. Through state leadership, Virginia can face the threats of climate change head on and do so in a way that makes clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio.

With these considerations in mind, I issued Executive Order 57 (EO 57) on June 28, 2016. Under EO 57, I directed the Secretary of Natural Resources to convene a work group to study and recommend methods to reduce carbon dioxide emissions from electric power facilities and grow the clean energy economy within existing state authority. The group consisted of the Secretary of Natural Resources, the Secretary of Commerce and Trade, the Director of the Virginia Department of Environmental Quality, the Director of the Virginia Department of Mines, Minerals and Energy, and the Deputy Attorney General for Commerce, Environment, and Technology. This group facilitated extensive stakeholder engagement over the last year, including six in-person meetings and a ninety-day public comment period, before compiling its recommendations and submitting a final report to me on May 12, 2017.

Among the most significant recommendations from the group is the need to develop regulations limiting the total amount of carbon dioxide emitted from electric power facilities. Given the nature of the climate change threat and the promise of clean energy solutions, I agree with this recommendation.

Accordingly, pursuant to the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10. 1-1300, et seq. and Virginia Code § 2.2-4000, et seq.:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that:

a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and

b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10. 1-1308.

Additionally, Executive Order 57 Work Group's "Report and Final Recommendations to the Governor" states that:

The Work Group received a number of presentations and written comments from stakeholders advocating for a regulation to limit carbon dioxide from power plants. These comments included recommendations that the Commonwealth join or participate in the Regional Greenhouse Gas Initiative (RGGI) or another regional trading program, that a price be put on carbon, and that Virginia strive to reduce its greenhouse gases by 30 to 40 percent by the year 2030. Although many stakeholders provided feedback focused on specific in-state targets (such as 30x30), the Work Group believes that it is important and necessary that Virginia work through a regional model, like the established and successful RGGI, in order to achieve lower compliance costs and address the interstate nature of the electric grid.

The Work Group recommends that the Governor consider taking action via a regulatory process to establish a 'trading-ready' carbon emissions reduction program for fossil fuel fired electric generating facilities that will enable participation in a broader, multi-state carbon market.

Substance

Please briefly identify and explain the new substantive provisions that are being considered, the substantive changes to existing sections that are being considered, or both.

The following is a general outline of the likely main elements of the new regulation directed by the Governor.

- CO_2 Budget Trading Program General Provisions (Purpose; Definitions; Measurements, abbreviations and acronyms; Applicability; Standard Requirements; Computation of time; Severability)
- Authorized Account Representative for CO_2 Budget Sources (Authorization and responsibilities of the CO_2 authorized account representative; Alternate CO_2 authorized account representative; Changing the CO_2 authorized account representatives and the alternate CO_2 authorized account representative; changes in the owner as and operators; Account certificate of representation; Objections concerning the CO_2 authorized account representative; Delegation by CO_2 authorized account representative and alternate CO_2 authorized account representative)
- Permits (General CO_2 budget permit requirements; Submission of CO_2 budget permit applications; Information requirements for CO_2 budget permit applications)
- Compliance Certification (Compliance certification report; Agency's action on compliance certifications)
- CO_2 Allowance Allocations (Virginia CO_2 trading program base budget; Timing requirements for CO_2 allowance allocations; CO_2 allowance allocations)
- CO_2 Allowance Tracking System (CO_2 Allowance Tracking System accounts; Establishment of accounts; CO_2 Allowance Tracking System responsibilities of CO_2 authorized account representative; Recordation of CO_2 allowance allocations; Compliance; Banking; Account error; Closing of general accounts)
- CO_2 Allowance Transfers (Submission of CO_2 allowance transfers; Recordation; Notification)
- Monitoring and Reporting (General requirements; Initial certification and recertification procedures; Out-of-control periods; Notifications; Recordkeeping and reporting; Petitions; CO_2 budget units that co-fire eligible biomass; Additional requirements to provide output data)

- CO_2 Emissions Offset Projects (Purpose, Definitions, General requirements, Application process, CO_2 emissions offset project standards, Accreditation of independent verifiers, Award and Recordation of CO_2 offset allowances)

Alternatives

Please describe any viable alternatives to the proposal considered and the rationale used by the agency to select the least burdensome or intrusive alternative that meets the essential purpose of the action. Also, include discussion of less intrusive or less costly alternatives for small businesses, as defined in § 2.2-4007.1 of the Code of Virginia, of achieving the purpose of the regulation.

Alternatives to the proposal will be considered by the board. It has been tentatively determined that the first alternative is appropriate, as it is the least burdensome and least intrusive alternative that fully meets the purpose of the regulatory action. The alternatives being considered, along with the reasoning by which any of the alternatives have been rejected, are discussed below.

1. Adopt the regulations to satisfy the provisions of Executive Directive 11 (2017). This option is being selected because it meets the stated purpose of the regulatory action: to develop a regulation that (i) ensures that Virginia is trading-ready to allow for the use of market-based mechanisms and the trading of carbon dioxide (CO_2) allowances through a multi-state trading program, and (ii) establishes abatement mechanisms that provide for a corresponding level of stringency to CO_2 limits imposed in other states with such limits.

2. Make alternative regulatory changes to those required by Executive Directive 11 (2017). This option is not being selected because it would not meet the stated purpose of the regulatory action.

3. Take no action to adopt the regulation. This option is not being selected because it would not satisfy the provisions of Executive Directive 11 (2017).

Public participation

Please indicate whether the agency is seeking comments on the intended regulatory action, including ideas to assist the agency in the development of the proposal and the costs and benefits of the alternatives stated in this notice or other alternatives. Also, indicate whether a public hearing is to be held to receive comments. Please include one of the following choices: (1) a panel will be appointed and the agency's contact if you're interested in serving on the panel is _____; (2) a panel will not be used; or (3) public comment is invited as to whether to use a panel to assist in the development of this regulatory proposal.

The agency is seeking comments on this regulatory action, including but not limited to: (1) ideas to be considered in the development of this proposal; (2) the costs and benefits of the alternatives stated in this background document or other alternatives; (3) potential impacts of the regulation; and, (4) impacts of the regulation on farm and forest land preservation. The agency is also seeking information on impacts on small businesses as defined in § 2.2-4007.1 of the Code of Virginia. Information may include: projected reporting, recordkeeping and other administrative costs; the probable effect of the regulation on affected small businesses; and the description of less intrusive or costly alternatives for achieving the purpose of the regulation.

The agency is seeking specific comment on how credits under a trading program should be allocated.

Anyone wishing to submit written comments may do so by mail, email or fax to Karen G. Sabasteanski, Department of Environmental Quality, P.O. Box 1105, Richmond VA 23218, phone 804-698-4426, fax 804-698-4510, email karen.sabasteanski@deq.virginia.gov. Comments may also be submitted through the Public Forum feature of the Virginia Regulatory Town Hall web site (http://www.townhall.virginia.gov**).** Written comments must include the name and address of the commenter. In order to be considered, comments must be received before midnight on the last day of the public comment period.

Public hearing at proposed stage

A public hearing will be held following the publication of the proposed stage of this regulatory action and notice of the hearing will be posted on the Virginia Regulatory Town Hall website (http://www.townhall.virginia.gov) and on the Commonwealth Calendar website (https://www.virginia.gov/connect/commonwealth-calendar).

Regulatory panel

Please indicate, to the extent known, if advisers (e.g., regulatory advisory panel or negotiated rulemaking panel) will be involved in the development of the proposed regulation. Indicate that 1) the agency is not using a panel in the development of the proposal; 2) the agency is using a panel in the development of the proposal; or 3) the agency is inviting comment on whether to use a panel to assist the agency in the development of a proposal.

The Board is using a panel to develop a proposal. The primary function of the panel is to develop a recommended regulation for Department consideration through the collaborative approach of regulatory negotiation and consensus. Notification of the composition of the panel will be sent to all panel members. Panel meetings are open to the public and will be announced via the Department website (http://deq.virginia.gov/Programs/Air/PublicNotices/AirRegulations.aspx) and on the Virginia Regulatory Town Hall website (http://www.townhall.virginia.gov).

Family Impact

Assess the potential impact of the proposed regulatory action on the institution of the family and family stability including to what extent the regulatory action will: 1) strengthen or erode the authority and rights of parents in the education, nurturing, and supervision of their children; 2) encourage or discourage economic self-sufficiency, self-pride, and the assumption of responsibility for oneself, one's spouse, and one's children and/or elderly parents; 3) strengthen or erode the marital commitment; and 4) increase or decrease disposable family income.

It is not anticipated that the proposal will have a direct impact on families.

REG\DEV\C17-01PD

Attachment 9

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Proposed Regulation
Agency Background Document

Agency name	State Air Pollution Control Board
Virginia Administrative Code (VAC) citation(s)	Part VII, 9VAC5-140
Regulation title(s)	Regulation for Emissions Trading
Action title	Establish a new regulation to reduce and cap carbon dioxide (CO_2) from fossil fuel fired electric power generating facilities by means of an interstate trading program (Revision C17)

This information is required for executive branch review and the Virginia Registrar of Regulations, pursuant to the Virginia Administrative Process Act (APA), Executive Orders 17 (2014) and 58 (1999), and the *Virginia Register Form, Style, and Procedure Manual.*

Brief summary

Please provide a brief summary (preferably no more than 2 or 3 paragraphs) of the proposed new regulation, proposed amendments to the existing regulation, or the regulation proposed to be repealed. Alert the reader to all substantive matters or changes. If applicable, generally describe the existing regulation.

The purpose of the proposed new regulation is, in accordance with Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from Electric Power Facilities and Growing Virginia's Clean Energy Economy," (i) ensure that Virginia is trading-ready to allow for the use of market-based mechanisms and the trading of carbon dioxide (CO_2) allowances through a multi-state trading program, and (ii) establish abatement mechanisms that provide for a corresponding level of stringency to CO_2 limits imposed in other states with such limits. The proposal includes two options on the base budgets, 33 million tons and 34 million tons, which will determine, based on a 3% annual reduction, the annual budgets and allocations for future years.

Acronyms and Definitions

Please define all acronyms used in the Agency Background Document. Also, please define any technical terms that are used in the document that are not also defined in the "Definition" section of the regulations.

CO_2 - carbon dioxide
CHP - combined heat and power
CPP - Clean Power Plan

CSAPR - Cross-State Air Pollution Rule
CT - combustion turbine
DMME - Department of Mines, Minerals and Energy
EGU - electric generating unit
ED 11 - Executive Directive 11
EPA - U.S. Environmental Protection Agency
ETS - Emissions Trading System
GHG - greenhouse gas
IRP - Integrated Resource Plan
MATS - Mercury and Air Toxics Standards
MW - megawatt
NGCC - natural gas-fired combined cycle
NRC - U.S. Nuclear Regulatory Commission
PEV - plug-in electric vehicle
PJM - PJM Interconnection
PSD - Prevention of Significant Deterioration
RGGI - Regional Greenhouse Gas Initiative
SCC - State Corporation Commission

Legal basis

Please identify the state and/or federal legal authority to promulgate this proposed regulation, including: 1) the most relevant citations to the Code of Virginia or General Assembly chapter number(s), if applicable; and 2) promulgating entity, i.e., agency, board, or person. Your citation should include a specific provision authorizing the promulgating entity to regulate this specific subject or program, as well as a reference to the agency/board/person's overall regulatory authority.

Section 10.1-1308 of the Virginia Air Pollution Control Law (Title 10.1, Chapter 13 of the Code of Virginia) authorizes the State Air Pollution Control Board to promulgate regulations abating, controlling and prohibiting air pollution in order to protect public health and welfare. Written assurance from the Office of the Attorney General that the State Air Pollution Control Board possesses the statutory authority to promulgate the proposed regulation amendments is available upon request.

Promulgating Entity

The promulgating entity for this regulation is the State Air Pollution Control Board.

State Requirements

Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia's Clean Energy Economy," directs the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10.1-1300 et seq., and Virginia Code § 2.2-4000, et seq.:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit CO_2 from electric power facilities that:

a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of CO_2 allowances through a multi-state trading program; and

b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on CO_2 emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10.1-1308.

Purpose

Please explain the need for the new or amended regulation. Describe the rationale or justification of the proposed regulatory action. Describe the specific reasons the regulation is essential to protect the health, safety or welfare of citizens. Discuss the goals of the proposal and the problems the proposal is intended to solve.

The regulation is needed to control CO_2 emissions in order to protect the public's health and welfare. The proposed regulation is being developed in order to meet the direction of Governor McAuliffe's Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia's Clean Energy Economy," which states:

> There is no denying the science and the real-world evidence that climate change threatens the Commonwealth of Virginia, from our homes and businesses to our critical military installations and ports. Rising storm surges and flooding could impact as many as 420,000 properties along Virginia's coast that would require $92 billion of reconstruction costs.
>
> The challenges and costs of bolstering resilience and minimizing risk are too great for any locality to bear alone. While the impacts are significant, there are technologies in the clean energy sector that could help mitigate these impacts while simultaneously creating jobs in twenty-first century industries. The number of solar jobs in Virginia has grown by 65 percent in the last year alone, and Virginia is now the ninth fastest growing solar jobs market in the country. Revenue for clean energy businesses in Virginia has increased from $300 million in 2014 to $1.5 billion in 2016. Through state leadership, Virginia can face the threats of climate change head on and do so in a way that makes clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio.
>
> With these considerations in mind, I issued Executive Order 57 (EO 57) on June 28, 2016. Under EO 57, I directed the Secretary of Natural Resources to convene a work group to study and recommend methods to reduce carbon dioxide emissions from electric power facilities and grow the clean energy economy within existing state authority. The group consisted of the Secretary of Natural Resources, the Secretary of Commerce and Trade, the Director of the Virginia Department of Environmental Quality, the Director of the Virginia Department of Mines, Minerals and Energy, and the Deputy Attorney General for Commerce, Environment, and Technology. This group facilitated extensive stakeholder engagement over the last year, including six in-person meetings and a ninety-day public comment period, before compiling its recommendations and submitting a final report to me on May 12, 2017.
>
> Among the most significant recommendations from the group is the need to develop regulations limiting the total amount of carbon dioxide emitted from electric power facilities. Given the nature of the climate change threat and the promise of clean energy solutions, I agree with this recommendation.
>
> Accordingly, pursuant to the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary

of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10. 1-1300, et seq. and Virginia Code § 2.2-4000, et seq.:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that:

a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and

b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10. 1-1308.

Additionally, Executive Order 57 Work Group's "Report and Final Recommendations to the Governor" states that:

> The Work Group received a number of presentations and written comments from stakeholders advocating for a regulation to limit carbon dioxide from power plants. These comments included recommendations that the Commonwealth join or participate in the Regional Greenhouse Gas Initiative (RGGI) or another regional trading program, that a price be put on carbon, and that Virginia strive to reduce its greenhouse gases by 30 to 40 percent by the year 2030. . . . Although many stakeholders provided feedback focused on specific in-state targets (such as 30x30), the Work Group believes that it is important and necessary that Virginia work through a regional model, like the established and successful RGGI, in order to achieve lower compliance costs and address the interstate nature of the electric grid.

The Work Group recommends that the Governor consider taking action via a regulatory process to establish a "trading-ready" carbon emissions reduction program for fossil fuel fired electric generating facilities that will enable participation in a broader, multi-state carbon market.

Substance

Please briefly identify and explain the new substantive provisions, the substantive changes to existing sections, or both. A more detailed discussion is provided in the "Detail of changes" section below.

1. The primary purpose of the regulation is to implement a declining cap on carbon emissions. The administrative means of accomplishing this will be effected by linking Virginia to RGGI, which is an established emissions trading program. An allowance will be issued for each ton of carbon emitted by an electricity generating facility. The company must then decide if it will reduce carbon emissions and sell the resulting additional allowances, or if it will not reduce carbon emissions and make up the difference with purchased allowances. The proposal includes two options on the base budgets, 33 million tons and 34 million tons, which will determine, based on a 3% annual reduction, the annual budgets and allocations for future years.

2. The mechanism for determining the cost of allowances will be a consignment auction.

3. A cost containment reserve allowance will be offered for sale at an auction for the purpose of containing the cost of CO_2 allowances in the event of higher than anticipated emission reduction costs. An emission containment reserve allowance will be withheld from sale at an auction for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.

4. Monitoring, recording, and recordkeeping requirements will be implemented to track compliance.

5. Conditional allowances will be allocated to the Department of Mines, Minerals and Energy (DMME) in order to assist the department for the abatement and control of air pollution, specifically, CO_2.

Issues

Please identify the issues associated with the proposed regulatory action, including: 1) the primary advantages and disadvantages to the public, such as individual private citizens or businesses, of implementing the new or amended provisions; 2) the primary advantages and disadvantages to the agency or the Commonwealth; and 3) other pertinent matters of interest to the regulated community, government officials, and the public. If there are no disadvantages to the public or the Commonwealth, please indicate.

1. Public: The primary advantage to the public would be health and welfare benefits associated with controlling carbon pollution. The program is designed to avoid any significant economic impacts.

2. Department: No significant advantages or disadvantages to the department can be identified. There may be a minor impact in terms of administering a new program.

Requirements more restrictive than federal

Please identify and describe any requirement of the proposal which is more restrictive than applicable federal requirements. Include a rationale for the need for the more restrictive requirements. If there are no applicable federal requirements or no requirements that exceed applicable federal requirements, include a statement to that effect.

There are no applicable federal requirements.

Localities particularly affected

Please identify any locality particularly affected by the proposed regulation. Locality particularly affected means any locality which bears any identified disproportionate material impact which would not be experienced by other localities.

There is no locality that will bear any identified disproportionate material air quality impact due to the proposed regulation which would not be experienced by other localities. None of the affected sources is owned or operated by a locality, and it is the generation of electricity that is directly subject to the regulation, not its end users.

Public participation

Please include a statement that in addition to any other comments on the proposal, the agency is seeking comments on the costs and benefits of the proposal, the impacts of the regulated community and the impacts of the regulation on farm or forest land preservation.

In addition to any other comments, the board is seeking comment on whether the initial Virginia CO_2 Budget Trading Program base budget for 2020 should be 33 million tons or 34 million tons, and declining accordingly by 3% per year as shown in Article 5. After considering public comment, the board will make a final selection of either 33 million tons or 34 million tons.

Additionally, the board is seeking comment on whether any fossil fuel power generating unit owned by an individual facility and located at that individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility should be exempt from the requirements of this regulation.

The board is also seeking comment on the costs and benefits of the proposal, the potential impacts of this regulatory proposal and any impacts of the regulation on farm and forest land preservation. Also, the board is seeking information on impacts on small businesses as defined in § 2.2-4007.1 of the Code of Virginia. Information may include 1) projected reporting, recordkeeping and other administrative costs, 2) probable effect of the regulation on affected small businesses, and 3) description of less intrusive or costly alternative methods of achieving the purpose of the regulation.

Anyone wishing to submit written comments for the public comment file may do so by mail, email or fax to the agency contact: Karen G. Sabasteanski, Policy Analyst, Office of Regulatory Affairs, Department of Environmental Quality, P.O. Box 1105, Richmond, Virginia, 23218 (email karen.sabasteanski@deq.virginia.gov, fax 804-698-4510). Comments may also be submitted through the Public Forum feature of the Virginia Regulatory Town Hall web site at: http://www.townhall.virginia.gov. Written comments must include the name and address of the commenter. In order to be considered, comments must be received by 11:59 pm on the last day of the public comment period.

A public hearing will be held following the publication of this stage and notice of the hearing will be posted on the Virginia Regulatory Town Hall website (http://www.townhall.virginia.gov) and on the Commonwealth Calendar website (https://www.virginia.gov/connect/commonwealth-calendar). Both oral and written comments may be submitted at that time.

Economic impact

Please identify the anticipated economic impact of the proposed new regulations or amendments to the existing regulation. When describing a particular economic impact, please specify which new requirement or change in requirement creates the anticipated economic impact.

Projected cost to the state to implement and enforce the proposed regulation, including: **a) fund source / fund detail; and** **b) a delineation of one-time versus on-going expenditures**	It is not expected that the regulation will result in any cost to the department beyond that currently in the budget. The sources of department funds to carry out this regulation are the general fund and the federal trust (grant money provided by EPA under § 105 of the federal Clean Air Act or permit fees charged to affected entities under the permit program). The activities are budgeted under the following programs (codes)/subprograms (codes): Air Protection Permitting (513025); Air Protection Compliance and Enforcement (513026); Air Protection Planning and Policy (513028); and Air Protection Monitoring and Assessment (513029). The costs are expected to be ongoing.
Projected cost of the new regulations or changes to existing regulations on localities.	The projected cost of the regulation on localities is not expected to be beyond that of other affected entities. Essentially, every individual and every organized entity--whether government or private--

	uses electricity, and it is the generation of that electricity that is directly subject to the regulation, not its end users. Furthermore, none of the affected sources is owned or operated by any locality.
Description of the individuals, businesses, or other entities likely to be affected by the new regulations or changes to existing regulations.	Electric power facilities with a capacity of >25 MW that operate on some form of fossil fuel (coal, natural gas) will be directly affected by the regulation.
Agency's best estimate of the number of such entities that will be affected. Please include an estimate of the number of small businesses affected. Small business means a business entity, including its affiliates, that: a) is independently owned and operated and; b) employs fewer than 500 full-time employees or has gross annual sales of less than $6 million.	There are 32 electric power facilities with a capacity of >25 MW operated by 12 companies located throughout the state that will likely be directly affected by the regulation. None of these entities is a small business. There may be limited indirect impacts on small businesses in general as discussed in greater detail below.
All projected costs of the new regulations or changes to existing regulations for affected individuals, businesses, or other entities. Please be specific and include all costs including: **a) the projected reporting, recordkeeping, and other administrative costs required for compliance by small businesses; and** **b) specify any costs related to the development of real estate for commercial or residential purposes that are a consequence of the proposed regulatory changes or new regulations.**	The primary purpose of the regulation is to implement a declining cap on carbon emissions. The administrative means of accomplishing this will be effected by linking Virginia to RGGI, which is an established emissions trading program. An allowance will be issued for each ton of carbon emitted by an electricity generating unit. It will then be up to the company to decide if it wants to reduce carbon emissions and sell its additional allowances, or or if it will not reduce carbon emissions and make up the difference with purchased allowances. Because there will not be a significant change to the allowance values RGGI already has in place, adding Virginia to the equation will not change compliance costs. The cost of allowances will be administratively managed by means of a consignment auction. In general, auctions have been known to decrease costs because the process is transparent (costs and prices are known), and the secondary market is not involved. Consignment auctions are revenue neutral, so the only actual cost to a facility would be the administrative cost of managing its consignment auction activities. Based on department experience with emissions trading programs and traditional auctions in the past (for example, under 9VAC5-140 for the NO_X Trading Rule, and CAIR), it is expected that these costs will be minor, unless a facility generates enough allowances to sell and realizes a profit from that sale. Generally speaking, wholesale electricity costs may go up or down depending on the price of allowances. Any impacts to residential consumers will be very small because wholesale costs are only a very small portion of a residential consumer's bill. Rates for commercial users may

	fluctuate more because wholesale costs are somewhat higher for commercial users, and industrial users, which pay rates close to wholesale, will experience the greatest of any potential impact. It is important to note that Virginia's energy market is regulated. This means that the Virginia SCC is responsible for monitoring electric rates such that Virginia's consumers (whether businesses, institutions or individuals) are protected from any dramatic changes to the electricity market. Regardless of what business decisions the affected utilities make in the future to comply with the carbon cap, Virginia's utility structure is designed to accommodate this type of pollution control program. The RGGI program is designed to avoid dramatic fluctuations in consumer costs. Thus far, electricity rates for RGGI customers have been stable over the life of the program, and this stability is expected to continue.
Beneficial impact the regulation is designed to produce.	To quote ED 11, "The challenges and costs of bolstering resilience and minimizing risk are too great for any locality to bear alone. While the impacts are significant, there are technologies in the clean energy sector that could help mitigate these impacts while simultaneously creating jobs in twenty-first century industries. The number of solar jobs in Virginia has grown by 65 percent in the last year alone, and Virginia is now the ninth fastest growing solar jobs market in the country. Revenue for clean energy businesses in Virginia has increased from $300 million in 2014 to $1.5 billion in 2016. Through state leadership, Virginia can face the threats of climate change head on and do so in a way that makes clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio." It is expected that the regulation will address the health and welfare impacts of climate change in an efficient, cost-effective manner. RGGI has successfully reduced carbon emissions with no negative economic impacts; see https://www.rggi.org/rggi_benefits. Emissions trading programs have proven to be very effective--with both traditional pollutants such as NO_X, and with more recently regulated pollutants such as CO_2--and an affiliation with RGGI will enable Virginia to quickly take advantage of a proven trading program.

Alternatives

Please describe any viable alternatives to the proposal considered and the rationale used by the agency to select the least burdensome or intrusive alternative that meets the essential purpose of the action. Also, include discussion of less intrusive or less costly alternatives for small businesses, as defined in § 2.2-4007.1 of the Code of Virginia, of achieving the purpose of the regulation.

Alternatives to the proposal are being considered by the board. The board has tentatively determined that the first alternative is appropriate, as it is the least burdensome and least intrusive alternative that fully meets the purpose of the regulatory action. The alternatives being considered by the board, along with the reasoning by which the board has rejected any of the alternatives being considered, are discussed below.

1. Amend the regulations to satisfy the provisions of the law and associated regulations and policies. This option is being selected because it meets the stated purpose of the regulatory action: to develop a carbon trading regulation in accordance with ED 11 (2017).

2. Make alternative regulatory changes to those required by the provisions of the law and associated regulations and policies. This option is not being selected because it would not meet the specific requirements of ED 11.

3. Take no action to amend the regulations and continue to not control carbon emissions via a trading program. This option is not being selected because it it would not meet the specific requirements of ED 11.

Regulatory flexibility analysis

Pursuant to § 2.2-4007.1B of the Code of Virginia, please describe the agency's analysis of alternative regulatory methods, consistent with health, safety, environmental, and economic welfare, that will accomplish the objectives of applicable law while minimizing the adverse impact on small business. Alternative regulatory methods include, at a minimum: 1) the establishment of less stringent compliance or reporting requirements; 2) the establishment of less stringent schedules or deadlines for compliance or reporting requirements; 3) the consolidation or simplification of compliance or reporting requirements; 4) the establishment of performance standards for small businesses to replace design or operational standards required in the proposed regulation; and 5) the exemption of small businesses from all or any part of the requirements contained in the proposed regulation.

This regulation meets the requirements of Executive Directive 11. Any less stringent compliance requirements, any delays in adopting the standards, any different compliance or reporting requirements, any substitution of performance standards, and any exemption of small businesses from these requirements will not meet the minimum requirements of ED11. Any such changes would compromise the effectiveness of the regulation in protecting the health and welfare of the public.

Public comment

Please summarize all comments received during the public comment period following the publication of the NOIRA, and provide the agency response.

Commenter	Comment	Agency response
1. General support (92 commenters)	General support for the regulatory action was expressed.	Support for the regulatory action is appreciated.

2. Advanced Energy Economy Institute (AEE Institute)	By implementing a carbon reduction policy with a flexible design that allows for a variety of technologies and services for that best suit the state, Virginia has the opportunity to modernize its electric grid for the benefit of consumers and the economy to accelerate a transition to a higher performing grid that is reliable, resilient, and affordable. To achieve those improvements, Virginia must continue to invest in 21st century electricity generation and grid technologies. Luckily, these same technologies will also lower carbon emissions. Forty such technologies are detailed in *Advanced Energy Technologies for Greenhouse Gas Reduction*. Renewable energy and energy efficiency are cost-effective mechanisms for carbon reduction but also expected to grow strictly on the basis of cost. The levelized cost of electricity for utility-scale wind and solar has declined such that these technologies are increasingly competitive. Renewable energy purchases that were once driven by state policies are increasingly made based on economics. Generation from zero- and low-carbon-emitting technologies can be used to meet baseload generation. These resources can integrate with variable renewable energy and also complement each other both technologically and economically, allowing the electricity system to provide reliable, low-carbon energy. High voltage direct current transmission can facilitate the integration of renewable energy technologies and reduce transmission line losses 30-50% compared to traditional alternating current systems. Demand response also provides grid benefits, including firm capacity reserves, system-wide peak shaving when demand is high, and ancillary services to facilitate the integration	DEQ agrees that renewable energy and energy efficiency are important elements in the reduction of carbon emissions. Although advanced energy programs as discussed by the commenter are recognized as important tools in the control of carbon emissions, they must be addressed in other, more appropriate venues. Electricity and energy policy in Virginia is primarily regulated and overseen by the Department of Mines, Minerals and Energy (DMME) and the State Corporation Commission (SCC).

	of renewable resources in a low-carbon manner. Demand response can directly reduce CO_2 emissions by more than 1% through peak load reductions and provision of ancillary services, and that it can indirectly reduce CO_2 emissions by more than 1% through accelerating changes in the fuel mix and increasing renewable penetration. Demand response can strengthen reliability. It also provides cost-effective alternatives to meeting peak demand, both locally and at the wholesale level, and can improve reliability while reducing peak power costs. Neighboring states are reducing energy costs for their customers through the deployment of utility peak-shaving demand response programs. These programs boost the local economy, as the majority of program payments are given to participating local businesses and organizations (e.g. school districts). Distributed resources can also provide grid benefits such as reduced congestion and increased reliability. These resources include distributed generation such as residential/commercial solar and wind, CHP, waste energy recovery, and fuel cells. Similarly, energy efficiency reduces congestion and peak demand, and reduces the impacts of changes in the capacity associated with retiring EGUs. Advanced grid technologies can help integrate and manage the growing diversity of renewable, low-emitting and traditional fossil generation. Energy storage also helps integrate renewables and reduces the need for peaking power plants–leading to fewer emissions–and thermal units to provide ancillary services such as frequency regulation and spinning reserves, allowing these traditional units to operate at more efficient heat rate blocks leading to fewer emissions.	

	Plug-in electric vehicles (PEVs) can be an important component to aid in GHG reduction and grid support as market penetration continues. PEVs both reduce emissions and provide grid energy storage. These advanced energy technologies can ensure that deployment of these technologies will have no significant adverse impacts on grid reliability and cost. In a recent report, AEE Institute described the grid benefits of the transforming energy sector. As the energy revolution sweeps the United States, greater fuel diversity has provided us with more options to meet our energy needs while maintaining, if not improving, reliability. *Changing the Power Grid for the Better* argues that incorporating more renewable energy, fast-ramping natural gas generation, a range of demand management techniques, and new resources like energy storage--rather than a return to a singular reliance on baseload resources--is the foundation of electric power system reliability. Advanced energy technologies and services will help Virginia balance cost, energy system performance, environmental, and public health considerations. These technologies are also well established in the U.S. and global marketplaces.	
3. AEE Institute	DEQ has discretion to distribute allowances in its state plan, either a) to Emitting Generating Units (EGUs); b) eligible resources; or c) both. Consider allocating allowances to all emission reduction measures, not just EGUs. This will ensure that the allowance allocation remains technology neutral and encourages competition among emission reduction measures, allowing for both existing future technologies to serve as compliance mechanisms. Although an auction method for	A consignment auction with updating output-based allocation has been selected as the mechanism for distributing and utilizing allowances. Consignment auctions are revenue neutral, and will enable Virginia to link to RGGI while recognizing its own energy distribution requirements.

	distributing allowances as currently employed by other carbon allowance systems including RGGI is not permissible under state law, a variation of allowance allocation that distributes to the load-serving entity or an updating output-based allocation could serve as a good alternative.	
4. American Council for an Energy-Efficient Economy (ACEEE)	Energy efficiency is an important strategy to reduce emissions. As it lowers electricity use, energy efficiency avoids emissions of CO_2 and other harmful pollutants, often at lowest cost. ACEEE estimates that if Virginia placed a cap on CO_2 emissions to reduce pollution 30% by 2030, Virginia could realize 100% of pollution reductions through energy efficiency policies and programs. As DEQ considers approaches to distributing allowances under a trading program, keep in mind that the selected approach will affect both CO_2 emissions and compliance costs during and after the compliance period. It is therefore essential for the success and long-term viability of the trading program that the method of allowance distribution drive lasting and cost-effective emission reductions. Energy efficiency is often the lowest-cost option to meet CO_2 reduction goals, and deployment should be encouraged under a CO_2 trading program. In an allowance trading program, CO_2 reductions from energy efficiency will help electric generating units (EGUs) meet the state's CO_2 emissions limit by reducing electricity production. However, this does not mean that energy efficiency deployment will increase - even when it is more cost-effective than other CO_2 reduction options. Current market and regulatory barriers to investment in energy efficiency can hinder its use as a compliance strategy in a trading program. DEQ should consider using methods for allowance distribution to help address these barriers to energy	DEQ agrees that energy efficiency is an important factor in the reduction of carbon emissions; energy efficiency efforts in the state are managed by the Department of Mines, Minerals and Energy (DMME). The RGGI states have proposed, as of this writing, a regional cap trajectory that will provide an additional 30% cap reduction by the year 2030, relative to 2020 levels. The proposed regional program changes include the addition of an Emissions Containment Reserve (ECR) wherein states can withhold allowances from auction if emission reduction costs are lower than projected. The proposed ECR is an innovative way to adaptively respond to supply and demand in the market. When this program is finalized, Virginia will align the regulation to meet any new requirements of RGGI states.

	efficiency deployment. We do not recommend a historical approach to allowance distribution, where allowances are given away to covered EGUs, as this is the least effective option. A historical approach does not promote the most cost-effective emission reduction measures in the state, such as energy efficiency.	
5. ACEEE	Auctions held by the state or another entity allow EGUs to purchase the allowances needed for compliance. The revenues from the sale of allowances can then be reinvested in activities that further reduce emissions, such as energy efficiency. RGGI has successfully distributed almost all allowances through regional auctions, with the largest portion of revenues reinvested in energy efficiency programs. According to RGGI, these investments are projected to save participants $3.62 billion on energy bills and avoid 12.9 million short tons of CO_2 pollution. As DEQ develops provisions to trade allowances through a multi-state trading program, joining RGGI and adopting the approach of auctioning allowances and reinvesting proceeds into energy efficiency programs and other purposes should be strongly considered. While a revenue-raising auction provides many benefits, there are other approaches for allowance distribution that would incentivize lasting CO_2 reductions and engage the private sector to invest in energy efficiency. A consignment auction will influence market responses in a similar way as a revenue-raising auction. Allowances are allocated for free, and recipients are then required to sell those allowances and use the revenue to repurchase the amount needed for compliance. This approach could avoid the need for legislative approval, and provide a transparent price signal and promotes long-term, cost-effective	DEQ agrees that a revenue-neutral consignment auction is the best means of achieving compliance, and the regulation has been developed with this approach.

	strategies to reduce CO_2 emissions.	
6. ACEEE	An updating output-based allocation rewards measures that deliver lasting CO_2 reductions. Allowances are distributed on the basis of electricity generated or demand avoided, relative to the amount of pollution emitted or fuel consumed. The allocation formula should be updated regularly to track generation and savings from efficiency, and reward future progress toward CO_2 reductions. This approach fosters technology-neutral competition, allowing energy efficiency project developers or investors to earn allowances alongside covered EGUs. It provides a transparent and predictable price signal, and ensures the activities that reduce the most CO, will receive the greatest number of allowances.	DEQ agrees that an updating output-based allocation approach will be the most effective means of reducing CO_2 and have designed the new program accordingly.
7. ACEEE	Set-asides allow for a portion of allowances to be budgeted for certain programs, such as energy efficiency. The amount of available allowances is capped at a certain percentage of the total allowance pool, therefore if the cap is exceeded certain projects will not be fully compensated for their contributions. While set-asides provide an incentive for qualified energy efficiency projects, the total allowances available are likely too small to allow for significant investment.	DEQ agrees that energy efficiency is an important factor in the reduction of carbon emissions; energy efficiency efforts in the state are managed by the Department of Mines, Minerals and Energy (DMME).
8. Appalachian Power Company (APCo)	APCo has demonstrated leadership in making carbon reductions over the past decade and will continue to deploy clean energy sources over the coming decades. As such, we feel that it is not in the best interest of Virginia to develop incremental carbon policies to intervene in an already ongoing transformation of the electric sector. On May 1, APCo filed its annual IRP with the Virginia SCC. In addition to projected load changes, IRPs are updated at regular intervals for changing market conditions as well as other external factors, including achieving	APCo's carbon reduction efforts are recognized and appreciated. DEQ does not agree that linking Virginia's CO_2 action to a broader CO_2 trading program could result in less control over Virginia's emissions trajectory and economic well-being. Joining RGGI is administratively practical and transparent, while meeting the important goal of reducing carbon emissions that are already having a detrimental economic impact to the state. Acting in concert with a program proven to reduce carbon emissions cost effectively will enable Virginia to reduce emissions while protecting the state's economic interests. The commenter's concerns are well-taken, however, we believe that this is the best approach in moving forward with the most

	potential environmental requirements. Such long-term plans--beyond any near-term 'actionable period'--can and do shift as such conditions warrant. APCo is required to provide an IRP that encompasses a 15-year forecast period (in this filing, 2017-2031). This IRP has been developed using the Company's current long-term assumptions for: customer load requirements; commodity prices; supply-side alternative costs; and demand-side program costs and impacts. In addition, APCo considered the effect of environmental rules and guidelines, such as the CPP, which could add significant costs and challenges to operations. State plans to implement this uncertain rule may not be finalized, let alone approved, for years. In preparing the IRP, APCo analyzed multiple scenarios, with differing commodity pricing conditions, as well as multiple internal load conditions. APCo has also conducted analyses that address certain aspects of compliance with the CPP. The 2017 APCo IRP suggests that APCo will not be integrating any new fossil resources into its system over the next 15 years. All incremental load increases are assumed to be met through installation of cost-effective wind and large-scale solar, both of which would provide customers with emissions-free energy, as well as the prospect of additional demand side management measures. The IRP also suggests that APCo may retire its remaining fossil units within Virginia by 2026. At such point that these units would be retired APCo would be left with a Virginia-domiciled generating fleet that is 100% carbon emissions free. In light of the transition that APCo has made and will continue to make in its generating fleet with respect to	certainty and least risk.

	emission reductions and generation diversification, APCo encourages DEQ and the board to recognize that planning practices already in place, such as the IRP process, can be appropriate means to establish a carbon reduction pathway. Given that the current Virginia regulatory process is robust and that CO_2 emissions have trended significantly downward, it not is in the state's best interest to take action on a small subset of emissions sources to address a concern that is global in nature. Linking Virginia's CO_2 action to a broader CO_2 trading program such as RGGI could ultimately result in Virginia having less control over its emissions trajectory and economic well-being. APCo is committed to working to ensure any regulatory action will be workable and equitable for APCo customers.	
9. Audubon Society of Northern Virginia	Climate change poses serious public health risks. In Northern Virginia, hotter summers make it more difficult to meet air quality standards. Our area is also vulnerable to vector-borne diseases, particularly Lyme Disease. We also face increased risks of flooding along the tidal Potomac and an increase in the number and intensity of extreme weather events. Extreme weather events also threaten our water and wastewater infrastructure, adding to the cost of public service. As shown by the shifting peak bloom date of the cherry trees in Washington, D.C., climate change is also disrupting ecosystems in Northern Virginia, putting pressure on migratory birds, whose reproduction is closely linked to the timing of spring. Climate change can cause a mismatch in the timing of food supplies and the birds and other wildlife that depend on them. The National Audubon Society's 2014 report concluded that global warming is the greatest threat to	The commenter's concerns are well taken. The purpose of this regulatory action is to meet the ED 11 requirement to control carbon emissions, and we believe that the proposal will meet that end.

	birds and other wildlife, that global warming's impacts could lead to the loss of 1/4 to 1/3 of all species on Earth, including many bird species. Carbon emissions from power plants will magnify these risks. We urge DEQ to draft stringent, science-based emission caps that move the state toward greater use of cleaner, renewable energy sources.	
10. CarbonShare.org	My comments focus on design elements of a carbon pricing system. The most comprehensive and easiest to administer point of regulation would be upstream. An upstream system would require only upstream companies to hold permits. They would be the buyers at the permit auction. An upstream system is the most comprehensive, and requires the least amount of administration from DEQ. An upstream system would also encompass transportation fuels, an important source of emissions. Because of the European Emissions Trading System (ETS) choice of administrative (free) allocations to emitters based on historic emissions instead of auctioning, the ETS had to figure out the change to the baseline to the aviation industry due to the volcano in Iceland. Virginia would have to recalculate free allocations to industry after every perturbation in the fuel and electricity markets. The ETS is overallocated, and the price of permits is low, yielding few emission reductions. By auctioning, Virginia could avoid subjecting DEQ to lobbying and political manipulation that free allocation entails. Administratively, it would be easier to just let companies figure out for themselves how many permits they need and let them buy them for themselves at auction. Auctioning is an important lesson from California's Cap & Trade program. The auction and price floor are primary factors	Linking to the successful, well-established RGGI program utilizing a revenue-neutral consignment auction has been selected as the most efficient and expeditious means of reducing carbon pollution in Virginia. Unlike the "nonregulated" RGGI states, Virginia is a "regulated" state and as such relies on the Virginia SCC to safeguard Virginia's electricity consumers. In other words, the distinct regulatory roles of DEQ and the SCC work in harmony such that pollution will be reduced from electric generating units while protecting the users of that electricity.

	contributing to the success the program has had thus far. The program would have had the disappointing results of the ETS without them. However, the California program is not perfect. It has missed opportunities to increase the amount of allowances auctioned, reducing the free allowances to industrial emitters, and returning more revenues collected back to households. Return carbon price revenues to households as a "climate dividend." The best way to return the value to consumers is through a dividend. The formula to do so is simple: auction allowances and return the funds to people. One problem with using funds on large infrastructure projects to reduce emissions is that the emission reductions may reduce the price of allowances, or change relative price of emissions between sectors, but result in no net emission reduction because the reductions achieved only create space for new emissions from other sectors under the cap. In other words, the space below the cap created by the infrastructure investment is simply filled up by emissions in other sectors. The goal of a carbon pricing program is not to build big capital projects. It is to provide an economic incentive to Virginians to change their economic behavior. Behavior change is better accomplished by returning the funds to Virginia households through a dividend. Spending revenues only on projects would neglect the regressive impacts of a carbon price on low-income families. Fossil fuel companies may use the sky, but we all own it together. It's a Commons. The equitable ownership of the commons should be a central theme in the design of a cap and trade system. The fossil fuel industry and other large	

	emitters should pay to use the atmosphere. If the sky belongs to us all, but its use becomes limited, then companies who use the sky should compensate citizens for its use. As long as pollution is free and has no price, companies may externalize those costs onto society. In many areas of environmental policy, fees on companies are used to raise funds to pay for clean-up and also made less-polluting alternative technologies more cost-effective. Technology alone is insufficient – We need an escalating carbon price: 1) Price on carbon 2) Dividends returned to people 3) Political acceptability for higher price on carbon 4) Actually affecting economic choices across all sectors, giving incentives to companies to produce lower carbon products, and for people to buy them 5) New technologies, transform the economy.	
11. Ceres BICEP (Business for Innovative Climate and Energy Policy) Network	An emissions trading program should create policy certainty and be stringent enough to send a strong and clear market signal for the transition to a low-carbon economy. Businesses need strong market signals and policy certainty in order to make decisions and investments for the long run. The program must be strong enough to drive emissions reductions and incentivize the uptake of clean energy. In addition, the program's design must be well thought-out and able to stand up to legal challenges in order to further foster certainty in the electricity market. A strong emissions reduction program would also encourage utilities to move in the direction their investors and customers increasingly want them to go. This year, an unprecedented size and scope of investors have engaged with investor-owned electric utilities, encouraging them to take climate change into account in their business decisions.	By linking to RGGI, Virginia will be taking part in a proven effective emissions reduction program that addresses the goals listed by the commenter.

12. Ceres	Linking emissions reduction programs with neighboring states would benefit Virginia ratepayers. A larger emissions trading market, as opposed to a one-state market, would create greater flexibility for compliance and more opportunities to achieve cost-effective emissions reductions. Interstate emissions trading markets have proven to be workable and economically feasible for participating states. RGGI, for example, is designed so that the participating states are able to maintain their autonomy and decide on their own whether to remain in the program and how to invest their RGGI auction revenues. RGGI states that have had the most economic and emissions-reduction success to-date are those that reinvest the largest portion of their auction revenues in clean energy projects and programs. Programs such as revolving loan funds, utility energy efficiency programs, and other innovative financing initiatives provide a smart option for reducing electricity bills while simultaneously helping states meet their carbon reduction goals. As early adopters of clean energy technologies, RGGI states have been able to unlock the economic benefits of the clean energy economy—innovation, investment, and jobs—very effectively. Virginia has an opportunity to reap the benefits of the clean energy economy as well.	DEQ agrees that interstate emissions trading markets are a workable and economically feasible means of reducing emissions. Joining RGGI will enable Virginia to use that market mechanism to reduce carbon emissions.
13. Ceres	An emissions reduction program should aim to maximize benefits to ratepayers through increased investments in renewable energy and energy efficiency. Virginia has an opportunity to seize the benefits of increasingly low-cost clean energy technologies and the investments, local jobs, and tax revenue that accompany the transition to a low-carbon economy. Clean energy can lower electricity costs and provide a valuable hedge against the volatility of fossil fuel prices. Meanwhile, energy	DEQ agrees that renewable energy and energy efficiency are important factors in the reduction of carbon emissions. Also noted elsewhere is the observation that Virginia is a "regulated" state and as such relies on the Virginia SCC to safeguard Virginia's consumers. The distinct regulatory roles of DEQ and the SCC work in harmony such that pollution will be reduced from electric generating units while protecting the users of that electricity. Renewable energy and energy efficiency projects are under the purview of the primary state agency for such projects, DMME.

	efficiency investments can provide quick paybacks, reduce overall demand for energy, and decrease energy bills. While auctioning emissions credits would provide an effective source of funding for reinvestments, if emissions credits are allocated, they should be allocated in a way that incentivizes investment in clean energy and the most cost-effective means of reducing emissions. Likewise, any value or revenue derived from the allocation or auctioning of credits should be used primarily to incentivize renewable energy and energy efficiency projects; such projects will best benefit ratepayers and the economy and will contribute to further emissions reductions in Virginia. An advisory board including legislators and key stakeholders would be prudent to determine the structure of allowance allocations. Furthermore, in order to protect Virginia's forests and foster a truly sustainable low-carbon economy, qualifying renewable energy projects should not include forest biomass for electricity projects.	
14. Ceres	Virginia should simultaneously unlock policy barriers to clean energy deployment. Thanks to Governor McAuliffe, Virginia has made strides in renewable energy deployment in recent years—but there is still significant untapped potential for energy efficiency and renewable energy investments. The state should remove barriers to corporate procurement of renewable energy. BICEP Network members and other major companies are increasingly making sustainability commitments and using renewable energy to power their operations. Clean energy allows businesses to hedge against the volatility of fossil fuel prices, lock in fixed rates, and reduce energy bills. Today, more than 63% of the Fortune 100 and nearly half	The SCC manages Virginia's electric generating and distribution, and the Department of Mines, Minerals and Energy (DMME) manages energy efficiency and renewable energy projects.

	of Fortune 500 companies have made commitments to reduce GHG emissions, procure more renewable energy, or invest in energy efficiency. By allowing large customers to participate in power purchase agreements, community solar projects, direct arrangements, third-party solar leasing, commercial clean energy financing, and cost-competitive, utility-administered green tariff programs (among other options), Virginia can continue to attract corporate investments while simultaneously lowering emissions. Furthermore, Virginia ratepayers could enjoy lower electricity bills by unlocking barriers to utility-administered energy efficiency projects and programs. Energy efficiency is low-hanging fruit in Virginia. The state has substantial opportunities to reduce energy waste. While the largest 30 electric utilities in the U.S. are saving, on average, almost 1% of retail sales annually through utility energy efficiency programs, Virginia's largest electric utility, Dominion Energy, only helped customers save 0.1% of sales in 2014.6 As a result, Virginia's utility energy savings are among the lowest in the country, causing ratepayers and businesses to miss out on the cost savings associated with decreased energy use.	
15. Chesapeake Physicians for Social Responsibility (83 signatures)	A well-designed program to reduce CO_2 emissions from power plants will allow Virginia to realize economic, environmental and public health benefits. Such a program will lead to reductions in the emissions of a large array of hazardous pollutants from coal-fired power plants, providing immediate public health benefits. Evidence shows that a well-designed carbon reduction program will help reduce electricity bills, boost local economies, and create local jobs. Reducing carbon emissions will help slow the pace of climate	ED 11 directs the department to develop a regulation that is "trading-ready" to allow for the use of market-based mechanisms and the trading of CO_2 allowances through a multi-state trading program, and we believe that linking to RGGI is the most realistic and effective means to accomplish this.

	change, which is a threat to public health and the economy of Virginia. This array of benefits has already been realized by the states that participate in RGGI, a program that has been reducing CO_2 emissions from power plants since 2009. RGGI has achieved an impressive reduction in pollution even as the economies of the member states grew. Between 2009-2014, RGGI states received $1.79 billion from the quarterly auctions of pollution allowances and have invested $1.37 billion. Most of these funds were spent to increase energy efficiency and support renewable energy, which created 30,000 job-years and produced additional economic benefits. Investments in energy efficiency programs have saved consumers $618 million on their electricity bills, and will provide future benefits of over $4.5 billion as the investments in energy efficiency continue to save power. By ensuring that the carbon regulation is trading-ready, Virginia will have the opportunity to join RGGI. One study estimates that by joining RGGI, Virginia could bring in $2.8 billion of revenue by 2030. This would mean more resources to protect the coastline, stronger energy efficiency programs, an increase in the use of renewable energy, more jobs, and better health outcomes.	
16. Dominion	To the extent the state pursues the development of state-specific regulations to address CO_2 emissions from power plants by establishing a statewide emissions cap, we generally support the concept of designing a program that would allow for emissions averaging and trading and would position the program to be trading-ready with linkages to either existing or future multistate trading programs as put forth by ED 11. However, we do not believe the directive compels the state to join a particular multi-state program, such	ED 11 directs the department to develop a regulation that is "trading-ready" to allow for the use of market-based mechanisms and the trading of CO_2 allowances through a multi-state trading program, and we believe that linking to RGGI is the most realistic and effective means to accomplish this.

	as RGGI, and urge the state to proceed cautiously but thoroughly in evaluating whether direct participation in existing trading programs would meet state environmental and energy goals and ensure the continued diversity, reliability and affordability of electricity.	
17. Dominion	The baseline and targets must accommodate for the dynamics of power imported into Virginia. The baseline must reflect and account for the fact that Virginia is a net importer of energy from more carbon-intensive out-of-state resources. The emission targets must allow for reasonable expansion of lower-emitting cleaner generation in the state to address energy needs and reduce imports of electricity in accordance with state energy policy. Setting a stringent cap on already cleaner generation in Virginia absent a similar level of reductions from neighboring states would increase the cost burden to Virginia generators and would likely encourage lower cost electricity imports from out-of-state sources that are more carbon-intensive and not subject to a carbon cost adder. This could result in the unintended consequence of curtailing or limiting the dispatch of highly efficient and lower emitting NGCC facilities in Virginia and encouraging the dispatch of higher emitting resources in neighboring states. With federal regulations currently stayed and under administrative review, few states outside of the RGGI program and along the west coast have or are proceeding with definitive carbon regulations. This includes all of the remaining states that are part of the PJM Interconnection (except Maryland and Delaware which are part of RGGI), which is the regional transmission organization that operates the wholesale electric grid in the mid-Atlantic region. At a minimum, any consideration of	Recent data shows that there is a general trend away from energy imports. Regardless, an updating output system incentivizes in-state generation, thus also addressing leakage. Indeed, the RGGI program is designed to track and avoid leakage through routine program review. DEQ agrees that other state and federal actions are important, and these activities are closely monitored and tracked. There is nothing to be gained by ignoring activities and trends outside the state, the PJM Interconnection, RGGI, and elsewhere. The baseline year is currently set at 2020, which will ensure that the Brunswick and Greensville units will be accounted for. Market-based programs are technology-neutral: a cap is set, and affected units have the flexibility to use whatever means they prefer to meet that cap. The commenter may consider any emissions reduction opportunities.

	reduction targets for Virginia should include an evaluation of what surrounding states are doing in the absence of federal requirements and impacts that may have on power markets, trading opportunities, leakage and economic growth. The baseline must also account for emissions from new generation projects, such as Dominion's Brunswick and Greensville natural gas-fired combined cycle (NGCC) facilities that have already received air permits and either already commenced commercial operation or are under construction. These facilities, each with capacity in excess of 1,300 MW, will operate some of the most efficient NGCC units with the most stringent GHG limits in the country and will serve as base load facilities. These units are critical in transitioning to a cleaner and less-carbon intensive generating fleet in Virginia. Emission targets should be based on the deployment of existing, commercially available technologies. Dominion continues to analyze emissions reduction opportunities and finds that the following measures hold the potential for ongoing emission improvements: • Heat rate efficiencies at existing coal-fired units; • Capacity improvements at existing NGCC units; • Maximize the dispatch from carbon-free nuclear and renewable sources first and then from lower-carbon NGCC units and other dispatchable resources; • Co-firing coal units with natural gas where economical at appropriate units with proximity to natural gas pipelines; Efficiency improvements within the electric transmission and distribution system; • Deployment of smart grid technologies such as voltage optimization software platforms.	

	We are also evaluating pumped hydroelectric storage, to be powered at least in part by renewable energy, as an additional energy supply for the state.	
18. Dominion	Although the intent of the Governor's directive is to set Virginia on a path to regulating carbon in the absence of federal action and the apparent demise of EPA's CPP, it does not, nor should it compel the state to establish emission targets equivalent to levels that would have been imposed under the CPP. We believe that the mass-based carbon emissions target EPA established under the CPP underestimated potential future growth to meet energy demand and was the most costly compliance alternative identified in the company's IRP. This type of program, particularly if implemented without flexible program designs including interstate trading, would be constraining for a state like Virginia which forecasts economic growth and an electric capacity deficit. Although established at the state-level, the limits required under the CPP presumed and envisioned a robust nationwide emissions trading program. Virginia should not impose more stringent emission reduction requirements to address a global environmental issue while other surrounding states we compete with economically have no established emission reduction goals or requirements. To the extent the CPP-based emission caps are considered, the caps should not be more stringent than the levels that would have been imposed under the CPP.	The intent of the regulation is to enable Virginia to link to RGGI, which establishes CO_2 emission reduction targets independently of the CPP or any other federal programs.
19. Dominion	The program should allow for realistic timeframes to achieve emission reduction goals. This will provide needed time for the ramp-up of new renewables, energy efficiency programs, and infrastructure improvements in order to maintain the state's fuel diversity and its goal to become more energy independent.	DEQ has worked diligently to ensure that its proposed timeframes are realistic.

	Reduction goals and implementation timelines must avoid premature retirement of remaining existing coal not otherwise shut down for compliance with other regulatory requirements.	
20. Dominion	The program must also recognize the critical role of extending the operation of Virginia's existing fleet of carbon-free nuclear generation. U.S. Nuclear Regulatory Commission (NRC) licenses for Dominion's existing nuclear stations begin to expire in 2032. The loss of approximately 3,500 MW of existing zero-emitting nuclear would significantly complicate compliance with any carbon reduction program in the post-2030 timeframe. To achieve electric output compatible with Dominion's North Anna and Surry nuclear power stations would require over 98,000 acres of solar panels. In addition, generation from nuclear units provide a critical and stable source of electricity in all weather conditions and are increasingly needed to maintain the reliability of the electric grid. Dominion is working with the NRC on evaluating and applying the current regulations as the basis for nuclear units to apply for a subsequent license extension to operate beyond 60 years. These existing regulations will be supported with enhancements to existing license renewal tools and guidance documents, adding additional aging-related system reviews and associated upgrades. The continued operation of these zero-emitting resources will require significant financial investments that are comparable to building new combined cycle gas units, the only other large base load source of generation, yet with the associated carbon emissions	As discussed elsewhere, the market-based cap-and-trade program is technology neutral. Although DEQ recognizes the value of all low- and zero-carbon generating sources, DEQ is specifically tasked with regulating fossil fuel generation.
21. Dominion	The state's reduction targets should not be based on a presumption that energy efficiency potential from policies in neighboring states can be repeated and achieved in Virginia.	Dominion's energy efficiency programs are recognized and appreciated.

	Energy efficiency programs historically have been financed by utilities. Dominion continually works to achieve operating efficiencies in our existing generating units to get more output with fewer emissions. We also offer a number of end-use energy savings programs to our customers. We continue to build upon our best in class energy efficiency and energy assistance program facilitated by the Governor's 2015 amendments to Senate Bill 1349 requiring the establishment of an energy assistance and weatherization program to serve low-income, elderly, and disabled customers as well as veterans. There remains significant potential for energy savings from consumer-side energy efficiency program and we remain committed to expanding participation in the current programs and offering consumers more choices to achieve energy savings. However, the expansion and consumer use of these programs depends on state laws and regulations that allocate resources and approve of demand-side programs. In Virginia, energy efficiency and demand side management programs must be approved by the SCC based on cost-benefit studies and strict measurement and validation processes. The ultimate successes of energy efficiency programs are generally within the control of the customer, not the utility. While utilities offer a range of consumer-friendly energy efficiency programs, they must nevertheless be prepared to serve their native load should such programs not be as successful as hoped. Accordingly, the state target should be based on well thought out and reasonable expectations of achievable energy savings and the compliance timelines must provide adequate time for the development,	

	approval and implementation of the energy efficiency programs required to achieve such objectives.	
22. Dominion	Renewable energy needs to be part of the solution and additional renewable generation sources of solar, on-shore and off-shore wind and pumped hydroelectric renewable energy with back-up generation support from our highly efficient natural gas units have a strong place in our future investment strategy. In 2013, Dominion had no generation from solar or on-shore wind sources. The company now has 423 MW of large-scale solar in Virginia either in operation, under construction, or under development, including power purchase contracts. All together, these facilities will produce enough electricity at peak output to power 105,000 homes. Our analysis shows that this rapid expansion of renewable energy, particularly highly cost effective solar energy, will continue to increase rapidly. Renewable energy, however, has some challenges. It requires a reliable source of backup for when it is not available. While we continue to see advancements with respect to battery storage technology, further innovation is needed to achieve both the scale and cost-effectiveness necessary for storing the vast amount of electricity that would be required for renewables to reliably power our economy. Natural gas is the lowest cost, cleanest and most reliable form of dispatchable generation to complement the integration of renewables to the electric grid. We will need our gas plants more and more to ramp up and down as Virginia grows its solar fleet. As noted previously, Virginia is home to some of the most efficient NGCC units with the most stringent GHG limits in the country. This technology will also serve to	Dominion's efforts to promote renewable energy are recognized and appreciated. There are indeed issues associated with renewable resources that, as discussed elsewhere, are more appropriately dealt with by other agencies (such as SCC and DMME) in a different context from this specific regulatory action.

	provide baseload generation to replace retiring coal plants. Another issue with renewables is the vast amount of land needed to produce sufficient power to meet energy needs. For example, 1 MW solar requires about 8 acres of real estate. In addition, significant grid improvements will be needed to accommodate growth in renewable energy. All of these challenges should be factored into assumptions regarding the expansion capability of renewable energy onto the electric grid in setting emission reduction targets.	
23. Dominion	The company is also examining the needed grid improvements to accommodate growth in renewable energy. Grid modernization is a national trend, and Dominion has taken an important first step with its strategic undergrounding program, an industry leading initiative to improve reliability which has received legislative support and approval from Governor McAuliffe in both 2014 and 2017 legislation. Building on these grid modernization efforts offers the opportunity to both better accommodate renewable energy and to improve customer reliability.	Dominion's grid improvement efforts are recognized and appreciated.
24. Dominion	In setting emission targets for the EGU sector, the state must recognize and account for the role and opportunity electrification of other sectors of the economy, such as transportation and cities, can play to reduce carbon emissions economy wide in the state. For example, Virginia intends to devote a significant amount of the environmental trust funds provided under the recent Volkswagen Consent Decree with EPA for promoting clean transportation technologies including the deployment of zero emission vehicle supply equipment, such as electric vehicle charging stations, as well as repowering large and medium-sized freight trucks, school and transit buses, port drayage trucks, locomotives, ferries and	DEQ agrees that the reduction of carbon must be approached holistically. The specific purpose of the regulatory proposal is to address one element of that goal.

	airport ground support and cargo handling equipment. Sale focus on the electric generation sector and establishing too stringent an emission cap on in-state generation could impact the ability of the state to holistically reduce carbon from other sectors of the economy.	
25. Dominion	In terms of affected EGUs subject to compliance obligations, the regulations should limit compliance applicability only to fossil fuel-fired EGUs that are greater than or equal to 25 MW. Small combustion turbines and boilers below this threshold should not be subject to compliance obligations under the program. This is consistent with many existing federal and state-level EGU-based emission reduction programs including EPA's Acid Rain program, CSAPR, MATS, and the northeast RGGI program. In addition, the program should not impose any compliance obligations upon units that burn biomass as their primary fuel. No emissions attributed to biomass firing should require allowances. This would be consistent with EPA's approach in developing the CPP which did not include biomass generation in establishing the baseline and state emission reduction targets and did not require biomass units to hold emission allowances or surrender emission rate credits under the proposed mass-based and rate-based model trading rules. This compliance exemption should also apply to the emissions apportioned to the burning of biomass for fossil fuel-fired units that co-fired with biomass. In 2013, Dominion made significant investments to converted three 51 MW units that used coal to 100% biomass, encouraged by EPA's prior determination that biomass was carbon neutral for PSD permitting. Close proximity to an ample supply of waste wood biomass as well as EPA's "carbon-neutral" policy for permitting under	The proposal limits compliance applicability only to fossil fuel-fired units that are greater than or equal to 25 MW, as is consistent with RGGI. Biomass-only units are not covered by this regulation, as it applies only to fossil fuel-fired generation. Fossil fuel-fired units that co-fire biomass must account for their CO_2 emissions and obtain allowances accordingly.

	the PSD effective at that time were key economic drivers for these projects. Given Dominion's significant investment in renewable wood waste and forest residuals biomass, it is important for our customers that biomass emissions be considered carbon neutral.	
26. Dominion	The state program should provide for maximum compliance flexibility including the following: • Use of emission trading with unlimited banking of allowances. The state should explore trading opportunities with other states and, where feasible, allow for linkages with other state programs to maximize market-based trading options. • Allow for multiple-year averaging to demonstrate compliance with any interim and final target. This concept was allowed in the final CPP and the RGGI programs allow for a tiered surrender of allowances over a three-year period. • Allow flexible resource options for use in demonstrating compliance with emission reduction requirements. These options should include: co-firing coal with natural gas or biomass; uprates at existing nuclear units; demand side and supply-side energy efficiency improvement programs, including voltage optimization and other electricity transmission and distribution efficiency improvements; generation from pumped storage.	Linking to RGGI will allow for these compliance flexibility goals.
27. Dominion	Although we have experience with RGGI though current and former assets in New England, we have serious concerns about potentially implementing the RGGI program in Virginia. • Although RGGI states have reduced carbon, the level of reductions achieved that can be attributed to RGGI itself is questionable. Emission reductions nationwide, including in Virginia, have been comparable to the reductions achieved in the RGGI states and have been primarily driven by fuel economics (low gas	As discussed elsewhere, linking to RGGI--a well-established, effective program--is the best means of quickly addressing carbon pollution in the most efficient way possible. ED 11 specifically tasks DEQ with controlling carbon generation by linking to an established state trading program, and the only such reasonably available and operating trading program is RGGI. One of RGGI's attractive features is that it is committed to ensuring a stable price structure, and utilizes routine program reviews to identify and improve means of accomplishing this goal.

	prices) and the corresponding shift from coal to natural gas as well as lower load growth due to the 2008 recession. • Although allowance prices in RGGI are currently around \$3.50/ton CO_2, the program is under an ongoing review and the RGGI states are exploring mechanisms that would set a trigger price, below which a certain amount of allowances would be held back from the auction in an effort to reduce amount of the allowance bank, increase the price and force more emission reductions. • RGGI is considering increasing the stringency of the regional emissions cap post-2020, reducing the cap by as much as 3.5 to 5% per year. Currently, the cap is reduced by 2.5% per year. • We have concerns about leakage if Virginia were to join RGGI and that our generating resources may not get dispatched if they are priced higher than other assets. As noted previously, we sell and buy our power into the PJM market which, with the exception of Maryland, consists of states that, to date, are not considering and have not developed or implemented carbon regulations. Accordingly, most other generators in the PJM market would not be subject to a carbon cost adder that generating units in Virginia would incur. This could result in curtailing or limiting the dispatch of lower emitting NGCC facilities in Virginia and encouraging the dispatch of higher emitting resources in neighboring states.	The commenter correctly states that RGGI is currently undergoing program review and the cap is being reconsidered. As of this writing, a regional cap trajectory that will provide an additional 30% cap reduction by the year 2030, relative to 2020 levels; the cap is expected to be, at this point, 3.5%. The proposed changes also include the addition of an Emissions Containment Reserve (ECR) wherein states can withhold allowances from auction if emission reduction costs are lower than projected. DEQ agrees that leakage is a concern; however, RGGI is structured such that leakage is monitored for and the program is adjusted as needed. As discussed elsewhere, an updating output system incentivizes in-state generation, thus also addressing leakage. RGGI is also designed to minimize economic impacts and keep compliance costs low, and DEQ believes that the market-based trading mechanisms in the proposal will accomplish the same. Routine program review will identify and correct problems should they occur.
28. Environmental Defense Fund (EDF)	A strong market-based mechanism for reducing carbon pollution from electric generating facilities will enable Virginia to achieve significant and cost-effective emission reductions. Market-based mechanisms that enable compliance with sector or economy-wide limits on CO_2 emissions with tradable compliance instruments are a cost-effective approach to achieve carbon pollution reductions	The proposal will enable the implementation of a strong, market-based mechanism for controlling carbon, i.e., linking to RGGI and establishing a consignment auction. The benefits of such an approach, as discussed by the commenter, are recognized. DEQ agrees that the reduction of carbon must be approached holistically. The specific purpose of the regulation is to address one element of that goal.

	with flexibility for regulated entities to pursue the lowest-cost abatement opportunities. EDF encourages DEQ to incorporate such a market-based mechanism into their regulatory proposal, setting a clear cap on carbon pollution from both new and existing units, issuing tradable allowances for every ton of carbon under the cap, and requiring owners of affected units to hold an allowance for every ton of carbon emitted. The regulation should cover all existing and new electric power facilities in Virginia that emit CO_2. Further, although this regulation will apply only to electric power facilities in Virginia, EDF encourages DEQ to pursue a market-based program design with flexibility to accommodate economy-wide expansion, noting electric power facilities contributed 30% of Virginia's CO_2 emissions in 2014. • DEQ should set stringent carbon emission limits over a transparently determined baseline. Emission limits (the cap) should result in concrete reductions in CO_2 emissions from the electric power sector below a business-as-usual baseline over the course of the program. DEQ should work with stakeholders to incorporate robust and reliable assumptions into a credible energy and economic modeling framework to establish a business-as-usual emissions baseline and to analyze the impacts of the policy in comparison to the baseline. The cap should ensure meaningful reductions in carbon pollution that safeguard public health and mitigate the impacts of climate change. • Data on prices, carbon emissions, and compliance behavior should be transparent and accessible. Transparent market design and implementation is important to assure fairness and certainty, and reduce transaction costs for market participants. Stakeholders,	As discussed elsewhere, leakage is an issue that is addressed by the updating output approach, which incentivizes in-state generation. RGGI also monitors for leakage via its regular program review process. Other market-based programs may become attractive in the future and will be considered at the appropriate time; at this stage, linking with RGGI is the most secure and reasonable approach.

	evaluators, and members of the public should be able to assess the progress toward achieving real emission reductions over time, along with other metrics of the program's success. For example, RGGI posts the results of its quarterly auctions, secondary markets, and yearly emissions data, and California posts a variety of market information about its program. • DEQ should evaluate program features that will mitigate leakage of emissions to surrounding states, including engaging with other states in the same market region on robust and aligned program design. Emissions leakage, or increases in carbon emissions in surrounding states due to shifting of facilities or other factors, would weaken effectiveness of the program in achieving real emission reductions. • EDF also encourages DEQ to explore program design features that can facilitate efficiencies through linkages with other market-based carbon reduction programs, including but not limited to RGGI. Virginia could develop a regulatory proposal aligned with the RGGI model rule and seek to formally join the RGGI program as a full participant, or could instead explore linkage opportunities where Virginia is not a full participant but DEQ accepts RGGI allowances for compliance with the Virginia program. Virginia should evaluate both options, as well as to evaluate opportunities to align a carbon regulatory framework in Virginia with carbon reduction efforts in additional states, particularly those states that are part of the PJM energy market. Virginia should also explore the potential to integrate with or use existing trading platforms.	
29. EDF	DEQ should engage with and address concerns of environmental justice and disadvantaged communities throughout development and implementation of the program. EDF urges DEQ to	DEQ will, as provided in the Public Participation Guidelines, provide opportunity for public comment on the impacts of the proposal. It is important to note that CO_2 is not a criteria

	meaningfully engage with disadvantaged communities--including communities situated near fossil fuel-fired power plants and communities with higher concentrations of low-income people, people of color, and otherwise vulnerable groups--throughout the process, by providing ample and accessible opportunities for public comment and other means of participation. DEQ should analyze impacts of the program on these communities and incorporate their recommendations to ensure the program does not impose disproportionate burdens on communities already vulnerable to the impacts of air pollution, climate change, and other factors.	pollutant and is thus not subject to a health-based standard. Unlike a conventional criteria pollutant such as NO_X or SO_2, CO_2 disperses quickly and does not create "hot spots" or localized problems. Fossil fuel-fired units are also subject to a host of other regulatory and permitting requirements that control emissions of criteria pollutants. Ultimately, the control of CO_2 will reduce global warming impacts and concomitant welfare impacts on disadvantaged communities. Also note that Virginia is a "regulated" state and as such relies on the Virginia SCC to safeguard Virginia's electricity consumers.
30. Lena Lewis	The cap must be set to reduce carbon emissions significantly. Virginia is a part of the Climate Alliance of States that have pledged to uphold the Paris Climate agreement, under which the U.S.'s was to reduce GHG by 26% of 2005 levels by 2025. This level of reduction puts Virginia on a path toward an 80% reduction. This pledge should determine the setting of the Virginia's carbon cap. Given that no other regulation has been put forward yet to reduce carbon emissions or other GHG emissions from other sectors of Virginia's economy, the majority of emissions cuts must come from the electricity sector. Some business-as-usual projections indicate that power sector carbon emissions will drop even without regulation. However, decreasing the rate of yearly emissions will not avert climate change if the emissions per year exceed the capacity to remove CO_2 from the atmosphere. The purpose of the cap is to put downward pressure on carbon emissions. The cap should decrease predictably and annually so that utilities can make long-term plans to reduce carbon. Reliable data is essential to setting the cap and allocating emission allowances effectively. Data must be sourced and	The cap will be set to reduce carbon emissions significantly, as consistent with the RGGI program. The updating output approach as well as the RGGI program review process will ensure that Virginia's carbon reductions are monitored and demonstrate continual effectiveness.

	analyzed by an independent, objective entity.	
31. Lena Lewis	Allowances should be distributed so that new generators, especially those that do not emit CO_2, are able to enter the market on a level playing field with incumbent generators. Locking in allowance distribution based on historic emissions rates of incumbent generators would fail to shift Virginia's power sector to lower carbon emissions in a fair, effective, or economically efficient manner. Distributing allowances based on updated energy output rather than on historic carbon emissions would create the incentive to lower carbon emissions. Each year, an energy generator would receive carbon allowances proportional to the previous year's energy output, while decreasing over time as the cap is lowered. Generators that generate a lot of low-carbon energy would receive more allowances than they would need, and could earn revenue by selling allowances to generators that emit more carbon. As the cap is lowered and allowances become more expensive, high-carbon generators will have the financial incentive to find a less carbon-intensive method of electricity generation. Energy output should be measured based on electricity consumed by customers, rather than all electricity generated by the supplier. This encourages generators to burn only enough fuel to meet consumer demand, while discouraging them from burning excess fuel for the purpose of increasing the next year's allocation of allowances. Generators receiving free allowances from the government must be required to sell all of their allowances, and then buy back their needed allowances. Linking with a preexisting carbon market would minimize emissions leakage and reduce costs to	Consistent with RGGI, the proposal is based on an updating output distribution approach, not historical. The benefits of an updating output approach are discussed elsewhere. Generally, Virginia's program will align with RGGI and its 3-year program review in order for the programs to operate in sync and, therefore, efficiently and effectively. Conditional allowances will be distributed to CO_2 budget units and DMME. These conditional allowances will then be consigned into auction, after which the conditional allowance becomes an allowance to be used for compliance purposes. DEQ agrees with the commenter that linking with RGGI will minimize leakage and stabilize costs. Linking to a market will increase the number of allowance trades, which will lead to price discovery of the true value of an allowance and increase economic efficiency; this is also true of the proposed consignment auction for the distribution of allowances.

	ratepayers, assuming that revenue is used to benefit ratepayers. Linking to a market will increase the number of allowance trades, which will lead to price discovery of the true value of an allowance and increase economic efficiency.	
32. Lena Lewis	The size of one carbon allowance, the timing of allocation distribution, the 3-year period in which power plants have to retire their allowances, a price floor, a program review, and other characteristics should synch with RGGI's schedule and parameters. Virginia must work with RGGI states to ensure that linking with their carbon market does not adversely affect their own emissions reductions or economies. Program review at regular intervals is needed to ensure that the cap is at an effective level to apply pressure to reduce carbon emissions and to improve program design.	By linking to RGGI, Virginia is committing to meet RGGI's overall structure and goals, including program review.
33. Lena Lewis; SELC	Allocation of tradable carbon allowances should be designed to lower carbon emissions in an economically efficient manner while also protecting residents from increased energy costs. Investor-owned utilities need to use revenues from allowance sales to keep rates low for customers, rather than add to their profits. Co-ops can use their allowance revenues to the benefit of their member-owners. The creation of a new market means the creation of new revenue. In no way should this revenue be permitted to increase investor-owned utility profits at the expense of ratepayers. Allowance recipients must consign all of their allowances to an auction. Allowances can be granted to generators based on the previous year's electricity output (not carbon emissions), and generators would be required to sell all of their allowances. Generators that use carbon-intensive sources would have to buy back allowances from the market. Generators with lower-carbon or zero-carbon	As discussed elsewhere, the energy market is regulated in Virginia by the SCC. The EO 57 Work Group recommended that the Governor convene an Environmental Justice Advisory Council (EJAC); see the response to comment 29.

	sources would not have to buy back so many allowances from the market, lowering their costs and increasing their revenue. Utilities must be required to report revenue from the carbon market to the SCC, and then apply that revenue toward offsetting the costs of buying allowances, thus keeping electricity rates as low as possible. Some of the revenue from allowance sales may need to be designated to offset the disproportionate effect of higher electricity rates on low-income customers. Any utility company claiming that carbon allowances are causing their electricity rates to increase must use carbon-market revenue to create utility-funded programs paying for energy efficiency improvements for low-income customers. Should electricity rates pass a certain threshold, utility companies should be required to provide direct assistance on electricity bills of low-income customers. Positive or neutral Impact on frontline communities is essential. As the cap for carbon emissions is lowered, it will create additional benefits of reducing associated co-pollutants that cause health problems in communities close to their source. DEQ needs to listen to and address the concerns of environmental justice advocates.	
34. Lena Lewis	Allowances should be fully bankable. Once generators have sold their allocated allowances, allowance owners should be permitted to save their allowances to use or sell when the price increases. Reducing emissions today will have the biggest environmental impact. CO_2 stays in the atmosphere a long time, and GHGs create an ever-accelerating greenhouse effect. If an owner of an allowance banks it, that is one unit of CO_2 not released today, which is more beneficial than a unit	The benefits described by the commenter will be realized in Virginia through linkage with RGGI.

	of CO_2 not released in the future. Virginia must have a reliable long-term market so that generators, utilities, residents and traders on the secondary market can make long-term plans to reduce carbon. Faith in continued existence of carbon cap-and-trade will reduce price volatility, encourage banking, and encourage investment in long-term in emissions reduction strategies . Transparency of prices, emissions, and compliance behavior will protect residents and build trust in the efficacy of the system. Buyers, sellers, and interested observers need to know prices on both the primary and secondary markets. The public needs proof that the program is working to lower emissions over time. For example, RGGI posts the results of its quarterly auctions, secondary markets, and yearly emissions data.	
35. Lena Lewis	Allowances should be fully tradable between power plants and any public or private entity, including individuals, both in-state and out-of-state. More trading leads to price discovery and a more economically efficient use of allowances.	A consignment auction has been determined to be the best method of dealing with allowances in Virginia.
36. Lena Lewis	Units that co-fire eligible biomass should be required to purchase allowances for all CO_2 emitted. The climate will react the same way to increased concentrations of CO_2, irrespective of its source. Likewise, waste-to-energy units that burn otherwise recyclable trash should fall under the same regulations.	Units that co-fire eligible biomass will be required to purchase allowances for all CO_2 emitted. Waste-to-energy units are not addressed in the RGGI model rule, and DEQ believes it is not appropriate to cover them in this rule at this time.
37. Lena Lewis	Carbon offsets are needed in addition to emissions reductions, not in place of them.	Although carbon offsets are allowed for, they have never been used in RGGI. Offsets were therefore not considered for the Virginia program.
38. LoudounPACE	Create rules that require reduction of use of all energy from Virginia's carbon producing power plants and reduces carbon pollution from those plants. Address disproportionate environmental and financial effects experienced by vulnerable communities by developing and promoting residential PACE	Linking to RGGI will effect carbon pollution reductions from Virginia's power plants. Other suggestions offered by the commenter are not directly germane to the goal of meeting ED 11 and linking with RGGI. Because RGGI is a market-based cap-and-trade program, the commenter's other suggestions are best addressed via the SCC and DMME. Additionally, consumer concerns are also

	programs to dramatically reduce energy consumption, thus lowering carbon footprints and energy costs. Grow the economy and reduce carbon pollution by maximizing investments in energy efficiency. Delete requirements for RECs and replace them with cost indexed carbon credits. Low cost per credit carbon reduction should sell for highest prices, preferably solar and wind. Work toward a Virginia carbon tax and dividend plan as put forward by the Citizens Climate Lobby.	discussed in greater detail in the response to comment 29.
39. Joy Loving	Monies derived from the cap must not go to the utilities, but should be distributed to all Virginians, with the following exceptions: A. Specify that the funds be designated for programs through which utilities will provide direct fuel assistance to those in need. B. Require utilities to establish and maintain effective energy efficiency programs enabling customers to cost-effectively reduce their energy usage; such programs should provide on-bill financing for such customers and should provide to those in need no/low cost energy efficiency upgrades. C. Require utilities to establish programs to offer options for renewable energy, including customer-owned community solar and other distributed renewable energy methods. Authorize utilities to facilitate customer participation through such mechanisms as on-bill financing. D. Require utilities to fund resilience programs to enable vulnerable communities to prepare for and ameliorate the worst effects of severe weather and other consequences of climate disruption. E. Require utilities to establish re-training to employees displaced by the transition from fossil fuel to renewable programs, by sponsoring and funding educational opportunities in affected communities, working through the Virginia colleges and universities. The regulations must provide that	A consignment auction is revenue neutral, which is why it was selected for the Virginia program. Utility programs as described by the commenter are directly managed by the SCC and DMME.

	utilities cannot charge customers who participate in any of these programs extra fees such as standby charges, net metering caps, or similar disincentives. If monies from the cap don't flow to utilities, then the state of Virginia should establish the programs described above.	
40. Joy Loving	Examine all available models for regional and state cap and trade or fee and dividend programs to identify strengths and weaknesses. Such programs include RGGI, the Western Climate Initiative, Southwest Climate Change initiative, etc. Work to find the best design from all models. Consult with PJM and representatives of all of its utilities, including municipals and co-ops.	It has been determined that linking to RGGI will be the most expeditious, practical, and effective means of reducing carbon emissions via a trading program. Although future participation in other programs is not ruled out and may occur at some later date when conditions warrant, ED 11 currently requires that Virginia link to RGGI.
41. Natural Resources Defense Council (NRDC)	The emissions limit must reduce emissions significantly below business-as-usual over the course of the program. To determine business-as-usual emissions and annual reduction levels, reliable, non-biased data and projections must be used to establish a baseline that is not artificially high, and to set a cap and meaningful annual reductions that protect human health. DEQ should rely on transparent estimations of least-cost estimates of what Virginia's business-as-usual emissions will likely be in year 1 of the program. Similarly, DEQ should avoid biased emissions projections that appear to be set unrealistically high.	Virginia is linking to RGGI, which, at this time, has proposed a regional cap trajectory that will provide an additional 30% cap reduction by the year 2030, relative to 2020 levels.
42. NRDC	Ensure the economic efficiency of the program by directing allowance value to consumer benefit, rather than toward utility or generator profit. Avoid imposing costs on ratepayers by awarding allowances directly to emitting generators for free. Doing so would allow the ultimate price of those allowances to flow to ratepayers in the form of higher wholesale electricity costs, while providing an unreasonable windfall profit to generators. To ensure economic efficiency and a transparent, undistorted allowance price that levels the playing field for	Virginia's consignment auction is revenue neutral. Also note that Virginia is a "regulated" state and as such relies on the Virginia SCC to safeguard Virginia's consumers. The distinct regulatory roles of DEQ and the SCC work in harmony such that pollution will be reduced from electricity generating units while protecting the users of that electricity.

	all generators, and to achieve maximum economic efficiency for citizens through allowance allocation, a standing Clean Energy Virginia Stakeholder Advisory Group should be established. The group's purpose would be to ensure the overall program and use of revenue is functioning transparently, efficiently, and effectively.	
43. NRDC	Maximize the environmental and climate change benefits of the program while avoiding market distortions and program inefficiency by including carbon emissions from forest-derived biomass generation within the carbon program and related emissions budgets. When establishing the statewide limits on CO_2, ensure that emissions from the combustion of forest-derived biomass to produce electricity - either through cofiring or in stand-alone plants - fall under the statewide emissions cap. EGUs that burn forest-derived biomass must hold allowances equal to stack emissions from that combustion, for several reasons. Forest-derived biomass is not a carbon neutral fuel and its emissions cannot be discounted based on anticipated future mitigation through forest regrowth or avoided decay. In addition, forest sustainability certification schemes or other standards offer little information about carbon emissions from biomass burning and are in no way a proxy for carbon neutrality. Moreover, interstate trading of allowances with RGGI states does not prevent Virginia from including biomass under its own carbon emissions limit.	Consistent with RGGI, biomass-only generating units are not covered by this rule. Fossil fuel-fired units that co-fire biomass must account for their CO_2 emissions and obtain allowances accordingly.
44. NRDC	Ensure integrity of the program is not eroded by emissions leakage by designing an economically efficient program with minimal market distortions; that maximizes consumer benefits through efficiency investments; and drives significant levels of in-state renewable energy development.	As discussed elsewhere, the output updating approach will encourage in-state power development, thus reducing the possibility of leakage; RGGI's program is review is also designed to detect and address leakage issues.

	These will deliver least-cost carbon reductions and lessen the impact of carbon prices on carbon-based power flows across state lines. Leakage can be minimized through development of Virginia's untapped, clean resources like solar and energy efficiency. As indicated in NRDC's modeling, imports of electricity decrease under a carbon limit, rather than increase, largely due to a buildout of native energy resources, rather than more costly electricity imports. Achieving this energy independence helps prevent leakage by obviating the need for electricity from outside the state. To ensure the program does not inadvertently lead to increased fossil-based electricity imports from out-of-state, DEQ should establish an annual program review process for the duration of the program, to assess whether interstate power flows are shifting as a result of the carbon price. This work could be incorporated into the Clean Energy Virginia SAG.	
45. NRDC	Allowances should comport with and be fully tradable on RGGI's pre-existing platform, which has low administrative costs and robust cybersecurity.	RGGI's platform does have low administrative costs and robust security, which is one of RGGI's several attractive features.
46. NRDC	Climate change is a fundamental environmental justice issue, as coastal communities and low-income communities ultimately bear the worst brunt of its impact. Therefore, the program should make significant cuts to CO_2 and ensure the consumer and energy efficiency benefits flow to the low-income citizens most impacted by climate change and energy costs. Additionally, because CO_2 is not harmful in locally higher concentrations, and there do not appear to be specific Virginia plants in proximity to at-risk communities whose capacity factors would increase under a carbon program, a carbon market in Virginia appears unlikely to create hot spots in frontline communities. As the cap for carbon emissions is lowered, it	As discussed in the response to comment 29, the EO 57 Work Group recommended that the Governor convene an Environmental Justice Advisory Council (EJAC). Also note that CO_2 standards are not a health-based, and that CO_2 does not create localized pollution problems; rather, control of CO_2 will help control global warming and its impacts on disadvantaged communities. The commenter correctly asserts that CO_2 is not harmful in locally higher concentrations. Additionally, routine program reviews provide the opportunity for any affected communities to bring attention to any potential issues.

	can also create additional benefits of further reducing associated co-pollutants in communities close to their source. The regular program review must incorporate an environmental justice review, to confirm that local co-pollutants are being reduced as predicted and that the program is not imposing an impact on any local community.	
47. NRDC	Any new market will need to be adjusted to ensure it is functioning efficiently and is driving significant and additional carbon pollution reductions. Program reviews can ensure that the cap is set at the correct level to reduce carbon emissions well beyond business as usual, while maximizing the development of a clean energy economy in the state. Virginia's program should undergo internal review on a regular basis, consistent with RGGI.	Virginia's program will undergo internal review on a regular basis, compatible and consistent with RGGI's program review process.
48. NRDC	NRDC retained ICF International to conduct NRDC's analysis of a RGGI-linked Virginia carbon cap and subsequent reductions, by utilizing ICF's Integrated Planning Model. NRDC's modelling indicates that capping carbon in Virginia with a well-designed program will significantly reduce carbon emissions, and at the same time drive significant economic benefits for families and ratepayers; promote energy diversity and independence; and improve public health by lowering total co-pollutants across the state.	These objectives will be achieved via linkage with RGGI.
49. NRDC	The program should be assessed by the consumer benefit delivered from such a plan: all emissions allowances have a dollar value as "discovered" in the marketplace. In a freely-transferrable market, a dollar value for emissions allowances will develop without government intervention. After allowance allocation, buyers and sellers, often with the help of emissions brokers, set a market price. The market then leaves plant	Virginia's participation in RGGI is posited on a revenue-neutral consignment auction. Also note that Virginia is a "regulated" state and as such relies on the Virginia SCC to safeguard Virginia's electricity consumers.

	owners with 2 options: (1) maintain emissions levels and purchase allowances or (2) reduce emissions levels and sell allowances to other plant operators for whom it is more cost effective to purchase allowances. In this market-based approach, the emissions reductions occur where cost-effective, and the allowances flow to the plants that will use them in a way that minimizes overall costs, while ensuring flexibility and reliability. Regardless of how the allowance was procured, the dollar value of each held allowance must be included by generators in their wholesale market bids to PJM. The value of allowances utilized by carbon emitters are then recouped by the generator when the electricity is sold. If DEQ does not design a carbon regulation and allocation method that ultimately delivers that allowance value back to the consumer, such a giveaway would serve as a publicly-subsidized windfall to generators, while consumers are saddled with higher costs. The program should be judged by the standard of whether or not the inherent full market value of allowances can be recovered from the generator that receives the electricity payment, and then reinvested in rebates, renewable energy, energy efficiency, and other investments that minimize compliance costs and maximize benefits to Virginia families. Conversely, the program should not allow the market value of allowances to accrue directly to generators as windfall profit, with no benefit to consumers to offset the higher wholesale electricity cost.	
50. NRDC	DEQ must decide in advance how it will initially allocate allowances. DEQ should ensure the inherent market value of the allowances accrues to Virginians and the Virginia economy, rather than result in a windfall to generators by distributing them to polluters for free; such an outcome would	Conditional allowances in the Virginia program will be allocated to fossil fuel-fired units as they are the regulated entity in the program. Consumer protections and energy efficiency efforts are under the purview of the SCC and DMME.

	equate to customers in Virginia transferring millions of dollars from their pockets to the balance sheets of generators. For example, according to the projected carbon allowance price of $3.90 in 2030, the value of Virginia's allocated 23.5 million allowances in 2030 would be over $90 million in that year. Generators will likely claim that they need allowances to fund their investments in equipment to reduce emissions, but because they are reimbursed for the allowance cost in the wholesale market, free allocation would result in "double payment," at the expense of the consumer.	
51. NRDC	DEQ could allocate allowance value on a pro rata basis to consumers via a consignment auction on behalf of electric distribution companies. Allowances would be distributed based on each company's percentage of total state load. In this approach, the dollar value of the allowances (as determined in the consignment auction) can return to electric billpayers via their distribution company, under the oversight of state regulators and other oversight bodies. The allowances are allocated on a pro rata basis to consumers via the distribution companies, based on each company's percentage of total state load. How those allowances are utilized would be overseen by the SCC, in consultation with DEQ, utilities, efficiency providers, DMME, consumer advocates, and other stakeholders. Given the range of generator types and ownership structures, allowances should be sold in a transparent and open manner, with regulated monopoly generators competing in an open, transparent market with merchants. Sale and transfer of money from any one regulated monopoly affiliate to another should be supervised by the SCC. The SCC would ensure that revenues from any allowances sold accrue to utility bill payers' benefit.	The SCC, as the commenter correctly asserts, monitors generation and related consumer issues.

	The SCC likely has sufficient authority to decide directly how the allowance revenues are utilized, to ensure maximum ratepayer benefit. Such benefits could take the form of cost-effective energy efficiency investment to lower customer bills (as well as further reduce carbon emissions from that distribution company); direct bill crediting; or investment in the most cost-effective zero-emissions resources to further reduce emissions and thus free up additional allowances. In RGGI, there have been significant benefits delivered to consumers as a result of investments of allowance proceeds. In the event Dominion or APCo must purchase allowances to meet the permitting obligations of one of their generators, SCC oversight can assure that such a decision to comply was the least-cost means available to the utility for meeting its generator's emissions obligations. Municipal boards and co-op boards would serve in a similar capacity, ensuring that any revenues or costs associated with allowances serve the best interests of their bill payers. Merchant generators would be assured access to allowances through sale of allowances by the distributions companies and the subsequent open allowance market. This approach is preferred for its efficiency. Administratively, DEQ already has experience with a similar NO_X allowance allocation and auction. Oversight bodies (the SCC and muni and co-op boards) are in place to ensure that allowance costs and related generation and compliance decisions are prudently incurred, and that any revenues are re-invested in such a way that serves the bill payers' best interests.	
52. NRDC	Another approach to maximize economic value of allowances is to allocate them to all generators of electricity or electric savings,	In order to meet the requirements of ED 11 and to link with RGGI, only fossil fuel generators are subject to the rule. Consumer protection is the purview of the SCC, not

	including fossil generators, non-emitting generators, and verifiable energy efficiency providers. The marketplace would determine the allowance prices, with additional revenue through allowance trading and the energy markets flowing from higher carbon emitters to zero-emitting resources. In that way, the value of the allowances flows indirectly to the consumer, through the lower energy costs of additional zero-emitting resources and additional energy efficiency. However, electricity customers would not directly receive the benefit of allowance-related revenue, nor receive the benefit of oversight of the disposition of such revenues.	DEQ. Note that no new source set-aside is being proposed. This will ensure a level playing field for renewable energy projects when they enter the market.
53. NRDC	Allocation of allowances directly to fossil emitters would allocate allowances directly to fossil generators, based on each generator's share of total emissions. This is the least economical method, because neither the state nor the bill payers recover any value; that value remains a windfall to generators and utilities. While the value of allowances would be included in PJM wholesale bids, no mechanism exists to ensure that recouped value is returned to the final electricity customer. This windfall would create transfer payments from customers to generators. If DEQ pursues this approach, it should be acknowledged that the state has made a direct decision to transfer the potential $90 million value of allowances in 2030 from the businesses and families of the state directly to the pockets of the power plant owners.	As discussed elsewhere, Virginia's consignment auction will be revenue neutral and no windfalls of any kind are expected. It is the role of the SCC role is to ensure that electricity customers are protected.
54. Southern Environmental Law Center (SELC) and the Virginia League of Conservation Voters	The regulation should cover any electric power facility that emits CO_2, regardless of fuel type, size, or date of construction and operation. EO 11 clearly states that the proposed regulation should "abate, control, or limit CO_2 emissions from electric power facilities." The only way to meaningfully achieve reductions in	As required by ED 11 and RGGI, fossil fuel-fired electric generation is the only type of generation covered by the rule; however, also note that there is no new source set-aside. By linking to RGGI, all fossil fuel-fired carbon-emitting electric generating units above 25 MW will be required to comply with the cap. Fossil fuel-fired units that co-fire biomass must account for their CO_2 emissions and

	total statewide carbon emissions is to cover all sources of carbon emission. If the regulation covers only currently-operating power plants, it will create a market perversion that incentivizes shifting generation to new power plants that the regulation does not cover. Not only will this shift undercut the fundamental purpose of reducing total emissions, it will also impose wholly unnecessary construction costs on Virginia electric customers as power generators invest billions of dollars of capital in otherwise redundant power plants. Likewise, the regulation should be blind to fuel type. To ensure complete reductions, the regulation should apply with equal force to any power plant that emits carbon. Finally, the regulation's scope should apply more broadly than the federal CPP. As can be seen from Dominion's 2017 IRP, it now proposes to build between 1,374 MW and 2,290 MW of new gas-powered combustion turbines (CTs). CTs are far less efficient than state-of-the art natural gas combined cycle plants, but because the now-defunct CPP did not apply to CTs, there existed a perverse incentive to build less-efficient power plants solely because they fell outside the CPP's orbit. DEQ should not allow this regulation to create similar market distortions and should cover all substantial carbon-emitting power plants. For instance, DEQ could follow RGGI and require all carbon-emitting power plants above 25 MWs to comply with the cap.	obtain allowances accordingly.
55. Sierra Club	The rule should apply to both new and existing sources and implement a declining mass-based cap that reduces CO_2 emissions from covered electric generation.	In order to link to RGGI, the proposal meets these criteria.
56. Sierra Club	The cap should decline steadily from the beginning of the program, and early CO_2 reductions should be incentivized. The aggregate cap should reduce emissions by the	The RGGI states have proposed, as of this writing, a regional cap trajectory that will provide an additional 30% cap reduction by the year 2030, relative to 2020 levels. The proposed regional program changes include

	greater of (a) 33-40% from 2015 levels by 2030 or (b) the level required to join a trading regime. The rule should require continued steady reductions through 2050 (to 80-95% of 2015 levels) subject to the possibility that the rate of reduction may be adjusted based upon experience new scientific evidence. An annual reduction of the cap for new and existing generation by approximately 1MM tons from a starting point based on 2015 emissions from covered sources illustrates a reasonable reduction path for interim (2030) and long-term (2050) purposes. Long-term investments (40-60 years for much generation) need long-term guidance.	the addition of an Emissions Containment Reserve (ECR) wherein states can withhold allowances from auction if emission reduction costs are lower than projected. The proposed ECR is an innovative way to adaptively respond to supply and demand in the market. When this program is finalized, Virginia will align the regulation to meet any new requirements of RGGI states.
57. Sierra Club	The basic elements of the proposed rule should be compatible with the operations and standards of RGGI. This would include the definitions of allowances (one short ton of CO_2), retirements matching emissions, adoption of key elements of RGGI's tracking and accounting system, etc. This would enable Virginia generators to trade within the state from the start (whether or not we join or link to RGGI), and within RGGI if a linkage or membership agreement is reached. Creating an incompatible program would be costly and not trading ready.	The commenter is correct that linking to RGGI is desirable, and that has been selected as the optimal path forward.
58. Sierra Club	Allowances can be allocated in several possible ways. We recommend that allowances be auctioned to all generators, with revenues being allocated among utilities or others in a manner that helps to achieve the rule's objectives. Some allowances should be held in reserve for possible distribution in order to stabilize markets or address other emergencies.	Conditional allowances will be allocated to the covered units via an update output approach. As discussed elsewhere, RGGI has built various protections into the program, such as the ECR, to ensure a stable market. Conditional allowances will be distributed to CO_2 budget units and DMME for consignment an auction, after which the conditional allowance becomes an allowance that can be used to demonstrate compliance.
59. Sierra Club	Program progress must be closely monitored and reported. This includes, for example, for results (prices, transfers, banks, and emissions), procedures and unintended consequences (e.g., pollution hot spots, market manipulation, emergencies, etc.).	DEQ agrees that program progress must be closely monitored and reported. RGGI's review process is robust and transparent, which is one of the reasons linking to RGGI is desirable.

	There should be periodic evaluations and, if needed, amendments should be made to reflect market experience and to improve outcomes.	
60. Sierra Club	Efforts should be made to join or link to a mass-based trading market, such as RGGI. A larger market will lower the costs and provide greater flexibility for market participants.There is no merit to the suggestion that RGGI is problematic because its members retail rates are higher than Virginia's. If anything, their higher energy prices will put downward pressure on CO_2 prices that markets will tolerate and that would benefit a lower cost state such as Virginia. Nor would there be loss of control as RGGI is a voluntary, collaborative organization.	Linking to RGGI has been determined to be the best path forward for effectively controlling carbon emissions.
61. Sierra Club	The final rule should be completed in 2018 and implemented in 2019.	The regulation is being developed as expeditiously as possible under the requirements of the Administrative Process Act.
62. Sierra Club	Issues pertaining to leakage – growth in GHG emissions incentivized but not covered by the rule – should be addressed in separate proceedings.	As discussed elsewhere, there are several safeguards built into the proposal and consistent with RGGI that will limit leakage.
63. Sierra Club (1,269 sponsored emails)	I am glad to see Virginia taking steps to cut carbon pollution to combat climate change, despite Trump's continued attacks on environmental protections. I am eager to see the state produce a strong, equitable, and scientifically sound plan to reduce greenhouse gas emissions. I request that DEQ use its authority to: Create a rule based on the strongest available science that significantly reduces carbon pollution from Virginia's power plants; ensure that Virginia residents benefit from any profits from carbon standards, especially front-line communities; address the disproportionate environmental burdens experienced by vulnerable communities; grow the clean energy economy by maximizing investments in zero-carbon wind, solar, and energy efficiency; and provide accessible public hearing opportunities in the evenings in	Support for the regulatory action is appreciated.

	multiple parts of the state to ensure all Virginians can fully participate in the rule-making process.	
64. 350 Central Virginia	Support limiting carbon pollution of power plants via a cap and trade program. The rule should use the best science available, and set up a capping system that will reduce carbon emissions over time as stringently as RGGI does, after a short lead-in period, in order to be effective. A rule that mandates that allowances received must be traded rather than directly used would be preferable. Apportionment of allowances should be based on amount of power supplied to ratepayers the previous year, not on emissions, and non-fossil fuel plants should receive allowances equally with fossil fuel plants. If possible, the rule should mandate that the net financial benefits of trading allowances be returned to the ratepayers.	Virginia is linking to RGGI, which is a well-established, effective cap-and-trade program. As discussed elsewhere, conditional allowances will undergo a consignment auction in order to become an allowance that can be used to demonstrate compliance.
65. University of Virginia Environmental and Regulatory Law Clinic	The Clinic presented to the Governor's EO 57 Work Group on "Opportunities to Address Carbon Pollution Under Existing State Law." The Clinic followed its presentation by submitting written comments to the Work Group. State law establishes a process for the adoption of regulations that are more stringent than applicable federal requirements. See Va. Code § 10.1-1308 A. Correspondingly, the federal Clean Air Act contains a states' rights savings clause, which allows states to promulgate their own, more stringent, air pollution regulations. See 42 USC 7416. The Act's citizen suit provision, 42 USC 7604(e), confirms that federal law does not restrict any right to enforce state standards. The Clinic's comments, however, also caution that establishing a multi-state trading program might present challenges, especially if the program were directly regulating out-of-state sources in a manner that conflicted with the law of the source state. In North Carolina, the Fourth Circuit found that regulated	Virginia will not be regulating out-of-state electric generating units.

	sources covered by a state-specific program must be within the state's boundaries: "only source state law … could impose more stringent emission rates than those required by federal law on plants located in those … jurisdictions." The court relied, in part, on International Paper Company v. Ouellette, which held that the Clean Water Act "precludes a court from applying the law of an affected State against an out-of-state source. … If a New York source were liable for violations of Vermont law, that law could effectively override both the permit requirements and the policy choices made by the source State." The state would need to consider the impact of this case law as it evaluates options for developing a trading-ready program that accounts for CO_2e allowances in a multi-state trading program. Dominion's Mount Storm Power Station in West Virginia, for example, might need to be excluded from such a program.	
66. Virginia Conservation Network (551 sponsored emails)	As Virginians, we appreciate the initiative taken by Governor McAuliffe/support Governor McAuliffe's leadership in the fight against climate change, but we know our work does not stop here. We request that DEQ use its authority to: Create a rule--based on the strongest available science--that significantly reduces carbon pollution from Virginia's power plants; ensure that Virginians--not utilities--benefit from any profits from carbon regulations; address the disproportionate environmental effects experienced by our most vulnerable communities; and reduce carbon pollution by incentivizing investments in zero-carbon solar, wind and energy efficiency.	Support for the regulatory action is appreciated.
67. Virginia Conservation Network (349 sponsored emails)	I am glad to see Virginia taking steps to cut carbon pollution in an effort to comply with the Paris Climate Accord. I am very excited for the state to create a plan that provides an equitable and just cap	Support for the regulatory action is appreciated.

	that will significantly reduce greenhouse gas emissions. To ensure that the policy best benefit Virginians, DEQ should: create a rule based on the strongest available science that significantly reduces carbon pollution from Virginia's new and existing power plants; ensure that Virginians--not utilities--benefit from any profits from carbon regulations especially our frontline communities; address the disproportionate environmental effects experienced by our most vulnerable communities; grow the economy and reduce carbon pollution by maximizing investments in zero-carbon wind, solar, and energy efficiency; and provide a transparent and accessible public process where all concerned Virginians can fully participate in the rulemaking process.	
68. Virginia League of Conservation Voters (214 sponsored emails)	I'm writing today to voice my support of a regulation in Virginia that cuts carbon pollution from power plants and allows us to trade carbon allowances with other states. With no help coming from the federal level in addressing climate change, it's up to states like Virginia to act. By cutting carbon emissions in Virginia, we have the opportunity to protect public health and safety while also creating jobs in the carbon-neutral renewable energy and energy efficiency sectors. And because we're joining up with a coalition of other states with carbon caps, action we take here in Virginia is greater than the sum of its parts. Carbon trading also creates the opportunity to bring revenue back to the state to aid in clean energy deployment and resiliency, money we shouldn't leave on the table or gift to our utilities. I urge you to proceed with a strong regulation that shows Virginia is a leader in addressing climate change and takes its responsibility seriously.	Support for the regulatory action is appreciated.
69. Virginia Poverty Law Center (VPLC)	The VPLC is glad there will be more opportunities for jobs and growth moving forward. We hope that low-income Virginians will benefit from	The consignment auction under which allocations will be traded is designed to be revenue neutral. In other words, utilities will be allocated a share of conditional allowances

	the jobs and opportunities, not be left behind in the new energy economy. This is an opportunity to help those struggling to find well-paying jobs to secure a brighter future. We will not comment on how to allocate carbon credits or the levels or limits on those allocations. Our comments focus on what happens if and when there are excess credits when Virginia participates in a regional CO_2 trading system. We are not experts in energy, but from our analysis, there may be a day when Virginia utility monopolies have an excess of credits which when sold, would generate revenue. If funds are generated from the sale of such credits, any regulation should contemplate how those funds are used. What happens to the funds generated is of keen interest to us. Regulations should ensure such proceeds should not be ceded to the utility monopolies for distribution to their shareholders, rather, any proceeds should be returned to the electricity consumers, particularly low-income rate-payers. Whether by programs that help with energy efficiency, or direct rebates on bills, the regulations should return any excess profits go to the consumer. As energy costs are expected to increase over time, the VPLC has been working to ensure more programs are in place to help weatherize and make homes of low-income families more energy efficient to help stabilize utility costs. We believe that either programs that help with energy efficiency, or direct rebates to consumers, should be the focus of any funds generated by trading.	that they must sell into the auction, and auction revenue is returned to the consignee. The consignment auction helps set the price of an allowance, not realize profits. While DEQ agrees that protecting electricity customers is important, that role properly belongs to the SCC.
70. Virginia Clinicians for Climate Action	A warming world poses significant risks to human health: extreme weather events; heat illness; air pollution; allergies; food and water contamination and infectious diseases. These effects are felt disproportionately in vulnerable populations, including children, the elderly and the disadvantaged. Federal Agencies have issued	The commenter's concerns are well taken. EO 57 and ED 11 are a direct result of concern around these issues, which is why DEQ has begun the process of preparing a regulation that will control carbon pollution in Virginia via linkage to RGGI. Support for the regulatory action is appreciated.

	reports and programs that address the health threats posed to humans by a changing climate. Leading national medical organizations including the American College of Physicians, American Academy of Pediatrics, American Public Health Association, and others have published statements and resolutions recognizing the threat that the changing climate poses to human health and promoting physician engagement. Health systems and hospitals in Virginia are vulnerable to extreme weather events and storm surges, which can significantly compromise patient safety and access to care. Regions of coastal Virginia, some of which are sites of major military installations, are at high risk to sea level rise and storm surge associated with climate change. Climate change is likely affecting plant and animal species in Virginia. Reported cases of several vector-borne diseases increased by 2-14 fold between 2006-2015 in Virginia. Changes in the natural world ultimately affect the health, prosperity and quality of life. Summer heat is becoming more oppressive in Virginia and heat-related injury is a cause of illness and death in Virginians, with young athletes, outdoor workers and the elderly at particularly elevated risk. For these reasons, Virginia Clinicians for Climate Action, a coalition of over 100 clinicians across the state, supports the Governor's plan as protective of public health.	
71. Jon Ward	I encourage Virginia to implement a CO_2 cap-and-trade system that includes an Emissions Containment Reserve, such as that being discussed among the RGGI states, to reduce the allotment of CO_2 allowances if their price falls to a specified level, incentivizing the market to reduce emissions below	The RGGI states have proposed, as of this writing, a regional cap trajectory that will provide an additional 30% cap reduction by the year 2030, relative to 2020 levels. The proposed regional program changes include the addition of an Emissions Containment Reserve (ECR) wherein states can withhold allowances from auction if emission reduction costs are lower than projected. The proposed

	the cap if market conditions allow. In working with other states in setting the cap's aggressiveness, recognizes the particular vulnerability of Virginia's tourist, fishing, military, and agricultural industries to worsening climate change and sea-level rise. Follow and regularly adapt to guidance from global climate-science experts as to the level of emissions reduction needed to restrict GHG concentrations to internationally agreed upon targets. Consider well-to-plant methane leakage in the calculation of GHG emissions attributable to power plants. Direct proceeds of CO_2 allowance sales to energy-efficiency projects and fossil-industry-worker retraining, and not to electric utilities. Utilities earn a return on equity to cover risks such as regulatory changes, and Virginia utilities have continued to build gas and coal plants in the face of climate consensus and clear likelihood of future federal and state regulations.	ECR is an innovative way to adaptively respond to supply and demand in the market. When this program is finalized, Virginia will align the regulation to meet any new requirements of RGGI states. This proposal is a CO_2 rule, not a greenhouse gas rule, and as such methane will not be addressed in this rulemaking. Methane may be addressed in other venues in the future as appropriate. Energy efficiency projects are managed and evaluated by DMME. Utilities are governed by the SCC.

Family impact

Please assess the impact of this regulatory action on the institution of the family and family stability including to what extent the regulatory action will: 1) strengthen or erode the authority and rights of parents in the education, nurturing, and supervision of their children; 2) encourage or discourage economic self-sufficiency, self-pride, and the assumption of responsibility for oneself, one's spouse, and one's children and/or elderly parents; 3) strengthen or erode the marital commitment; and 4) increase or decrease disposable family income.

It is not anticipated that the proposal will have a direct impact on families.

Detail of changes

Please list all changes that are being proposed and the consequences of the proposed changes; explain the new requirements and what they mean rather than merely quoting the proposed text of the regulation. If the proposed regulation is a new chapter, describe the intent of the language and the expected impact. Please describe the difference between existing regulation(s) and/or agency practice(s) and what is being proposed in this regulatory action. If the proposed regulation is intended to replace an emergency

*regulation, please list separately: (1) all differences between the **pre**-emergency regulation and this proposed regulation; and 2) only changes made since the publication of the emergency regulation.*

Section number	Proposed requirements	Other regulations and law that apply	Intent and likely impact of proposed requirements
Article 1 - CO_2 Budget Trading Program General Provisions.			
9VAC5-140-6010	Purpose	None.	Establishment of the Virginia component of the CO_2 Budget Trading Program. Needed to provide clarity.
9VAC5-140-6020	Definitions	None.	Terms defined. Needed to assure that the regulation is understood and will operate properly.
9VAC5-140-6030	Measurements, abbreviations and acronyms.	None.	Needed to assure that the regulation is understood and will operate properly.
9VAC5-140-6040	Applicability		Defines sources to which the regulation applies. Needed in order that the regulation apply to certain affected sources. Implementation of this regulation will have an impact on those sources that are directly subject to the requirements of the rule. Note that the board is seeking comment on whether any fossil fuel power generating unit owned by an individual facility and located at that individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility should be exempt from the requirements of this regulation (subsection B).
9VAC5-140-6050	Standard requirements	None.	General requirements for permits, monitoring, holding and management of CO_2 allowances, excess emissions, recordkeeping and reporting, and liability. Needed in order for the program to operate properly.
9VAC5-140-6060	Computation of time	None.	How to define the beginning and ending of an activity. Needed in order for the program to operate properly.
9VAC5-140-6070	Severability	None.	Clarifies that the remainder of rule is not rendered invalid by the invalidity of another part of the rule. Needed in order for the program to operate properly.
Article 2 - CO_2 Authorized Account Representative for CO_2 Budget Sources.			
9VAC5-140-6080	Authorization and	None.	Details how this individual is

	responsibilities of the CO_2 authorized account representative		selected and authorized, and their key roles. Needed in order for the program to operate properly.
9VAC5-140-6090	Alternate CO_2 authorized account representative	None.	Details how this individual is selected and authorized, and their key roles. Needed in order for the program to operate properly.
9VAC5-140-6100	Changing the CO_2 authorized account representatives and the alternate CO_2 authorized account representative; changes in the owners and operators	None.	How changes are made to account representatives, and owners and operators. Needed in order for the program to operate properly.
9VAC5-140-6110	Account certificate of representation	None.	How account representatives are to be certified. Needed in order for the program to operate properly.
9VAC5-140-6120	Objections concerning the CO_2 authorized account representative	None.	How to deal with any disputes relevant to the account representative. Needed in order for the program to operate properly.
9VAC5-140-6130	Delegation by CO_2 authorized account representative and alternate CO_2 authorized account representative	None.	Enables the account representatives to delegate their authority to other persons. Needed in order for the program to operate properly.
Article 3 - Permits.			
9VAC5-140-6140	General CO_2 budget permit requirements	None.	References pertinent permitting regulations. Needed to assure that existing permitting requirements are met.
9VAC5-140-6150	Submission of CO_2 budget permit applications	None.	Requires a budget permit application by a certain date. Needed in order for the program to operate properly.
9VAC5-140-6160	Information requirements for CO_2 budget permit applications	None.	Lists elements concerning the CO_2 budget source for which the application is submitted. Needed in order for the program to operate properly.
Article 4 - Compliance Certification.			
9VAC5-140-6170	Compliance certification report	None.	Requires the source to certify whether each CO_2 budget unit was operated in compliance with the requirements of the CO_2 Budget Trading Program. Needed in order for the program to operate properly.
9VAC5-140-6180	Action on compliance certifications	None.	Explains how the compliance certification is reviewed. Needed in order for the program to

			operate properly.
Article 5 - CO_2 Allowance Allocations Note that two versions of 9VAC5-140-6190 and 9VAC5-140-6210 are provided for comment. The board seeks comment on whether the base budget should be 33 million tons or 34 million tons, with corresponding 3% per year reductions. The first version represents a 33 million ton base budget, and the second version represents the 34 million ton base budget.			
9VAC5-140-6190	Base budgets	None.	Base budgets are established from 2020 onward. The board is seeking comment on whether the initial Virginia CO_2 Budget Trading Program base budget for 2020 should be 33 million tons or 34 million tons, and declining accordingly by 3% per year. Needed to effect the carbon pollution reduction that ED 11 require of this regulation.
9VAC5-140-6200	Undistributed and unsold CO_2 allowances	None.	Explains how the department may retire undistributed and unsold allowances. Needed for the program to operate properly.
9VAC5-140-6210	CO_2 allowance allocations	None.	Describes how the department will allocate allowances. CCR and ECR allowances as described in Tables 140-5A and B are tied to the 2020 base budget and as such the board is seeking comment as to whether these numbers should be tied to a base budget of 33 million tons or 34 million tons. Needed to effect the carbon pollution reduction that ED 11 requires of this regulation.
9VAC5-140-6215	CO_2 allocation methodology		Describes the methodology for allocating allowances using net electric output. Needed for the program to operate properly.
Article 6 - CO_2 Allowance Tracking System			
9VAC5-140-6220	CO_2 Allowance Tracking System accounts	None.	Establishes a system in order for tracking compliance accounts. Needed in order for the program to operate properly.
9VAC5-140-6230	Establishment of accounts	None.	Explains how compliance accounts are established and managed. Needed in order for the program to operate properly.
9VAC5-140-6240	CO_2 Allowance Tracking System responsibilities of CO_2 authorized account representative.	None.	Requires that all submissions pertaining to the account are made only by the authorized account representative. Needed in order for the program to operate properly.
9VAC5-140-6250	Recordation of CO_2 allowance allocations	None.	Describes how the department records allowances. Needed in

			order for the program to operate properly.
9VAC5-140-6260	Compliance	None.	CO_2 allowances that meet certain criteria are available to be deducted in order for a source to comply with the CO_2 requirements for a control period. Needed in order for the program to operate properly.
9VAC5-140-6270	Banking	None.	Requires that CO_2 allowances remain in account until deducted or transferred. Needed in order for the program to operate properly.
9VAC5-140-6280	Account error	None.	Allows corrections to be made. Needed in order for the program to operate properly.
9VAC5-140-6290	Closing of general accounts	None.	Describes how to close an account. Needed in order for the program to operate properly.
Article 7 - CO_2 Allowance Transfers			
9VAC5-140-6300	Submission of CO_2 allowance transfers	None.	Specifies how to submit transfers. Needed in order for the program to operate properly.
9VAC5-140-6310	Recordation	None.	Describes the recordation of transfers. Needed in order for the program to operate properly.
9VAC5-140-6320	Notification	None.	Explains notification of transfers to each party. Needed in order for the program to operate properly.
Article 8 - Monitoring and Reporting			
9VAC5-140-6330	General requirements	None.	Generally requires a source to comply with monitoring, recordkeeping and reporting requirements as provided in this regulation and 40 CFR Part 75. Needed to assure that all pertinent state and federal requirements are met.
9VAC5-140-6340	Initial certification and recertification procedures	None.	Facilities may be exempt under certain circumstances. Needed in order for the program to operate properly.
9VAC5-140-6350	Out-of-control periods	None.	What to do when a monitoring system fails to meet QA/QC or other requirements. Needed to assure compliance.
9VAC5-140-6360	Notifications	None.	Notification requirement. Needed in order for the program to operate properly.
9VAC5-140-6370	Recordkeeping and reporting	None.	Monitoring plan recordkeeping and reporting requirements. Needed to assure compliance.
9VAC5-140-6380	Petitions	None.	How to request approval for an

			alternative to any requirement of 40 CFR Part 75. Needed to assure compliance.
9VAC5-140-6390	Reserved	None.	
9VAC5-140-6400	Additional requirements to provide output data	None.	Additional steps to be taken when determining output. Needed in order for the program to operate properly.
Article 9 - Auction of CO_2 CCR and ECR allowances			
9VAC5-140-6410	Purpose	None.	General purpose of the article. Needed to provide clarity.
9VAC5-140-6420	General requirements	None.	Describes information required in the auction notice, rules for sale of allowances, information on the reserve price, and withholding ECR allowances from an auction. Needed in order for the auction to operate.
9VAC5-140-6430	Consignment auction	None.	How conditional allowances are auctioned at consignment and converted to allowances used for compliance. Needed in order for the auction to operate.

TEMPLATES\PROPOSED\TH02
REG\DEV\C17-04TP

Attachment 10

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Proposed Regulation
Agency Background Document

Agency name	State Air Pollution Control Board
Virginia Administrative Code (VAC) citation(s)	Part VII, 9VAC5-140
Regulation title(s)	Regulation for Emissions Trading
Action title	Establish a new regulation to reduce and cap carbon dioxide (CO_2) from fossil fuel fired electric power generating facilities by means of an interstate trading program (Revision C17)
Date this document prepared	

This information is required for executive branch review and the Virginia Registrar of Regulations, pursuant to the Virginia Administrative Process Act (APA), Executive Order 14 (as amended, July 16, 2018), the Regulations for Filing and Publishing Agency Regulations (1 VAC7-10), and the *Virginia Register Form, Style, and Procedure Manual for Publication of Virginia Regulations.*

Brief Summary

Please provide a brief summary (preferably no more than 2 or 3 paragraphs) of this regulatory change (i.e., new regulation, amendments to an existing regulation, or repeal of an existing regulation). Alert the reader to all substantive matters. If applicable, generally describe the existing regulation.

The purpose of the re-proposed new regulation is, in accordance with Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from Electric Power Facilities and Growing Virginia's Clean Energy Economy," (i) ensure that Virginia is trading-ready to allow for the use of market-based mechanisms and the trading of carbon dioxide (CO_2) allowances through a multi-state trading program, and (ii) establish abatement mechanisms that provide for a corresponding level of stringency to CO_2 limits imposed in other states with such limits. The re-proposed regulation includes a base budget of 28 million tons, which will determine, based on a 3% annual reduction, the annual budgets and allocations for future years. In accordance with ED 11, the report of the Executive Order 57, and a formal determination by the Office of Attorney General, these requirements apply to fossil fuel-fired electric generating facilities.

The original proposal, which underwent public comment from January 8 through April 9, 2018, included two options on the base budget of 33 and 34 million tons. DEQ proposed and the board approved a new base budget of 28 million tons based on new modeling and other information. Other substantive changes include the recognition of offsets from other participating states, exemption of fossil fuel units that co-fire

with biomass from CO_2 accounting, a more detailed description of exempt industrial sources, a more detailed description of how the cost containment reserve will be managed, a new section allowing for participation in a non-consignment auction, and a new section requiring program monitoring and review. The proposal was also updated to reflect the latest version of the RGGI model rule.

Acronyms and Definitions

Please define all acronyms used in the Agency Background Document. Also, please define any technical terms that are used in the document that are not also defined in the "Definition" section of the regulations.

CO_2 - carbon dioxide
CPP - Clean Power Plan
CSAPR - Cross-State Air Pollution Rule
DMME - Department of Mines, Minerals and Energy
EGU - electric generating unit
ED 11 - Executive Directive 11
EO 57 - Executive Order 57
EPA - U.S. Environmental Protection Agency
GHG - greenhouse gas
IRP - Integrated Resource Plan
MW - megawatt
NGCC - natural gas-fired combined cycle
PJM - PJM Interconnection
PSD - Prevention of Significant Deterioration
RGGI - Regional Greenhouse Gas Initiative
SCC - State Corporation Commission

Mandate and Impetus

Please identify the mandate for this regulatory change, and any other impetus that specifically prompted its initiation (e.g., new or modified mandate, petition for rulemaking, periodic review, board decision, etc.). For purposes of executive branch review, "mandate" has the same meaning as defined in Executive Order 14 (as amended, July 16, 2018), "a directive from the General Assembly, the federal government, or a court that requires that a regulation be promulgated, amended, or repealed in whole or part."

The mandate for this regulation is Executive Directive 11 (2017).

Legal Basis

Please identify (1) the agency or other promulgating entity, and (2) the state and/or federal legal authority for the regulatory change, including the most relevant citations to the Code of Virginia or Acts of Assembly chapter number(s), if applicable. Your citation must include a specific provision, if any, authorizing the promulgating entity to regulate this specific subject or program, as well as a reference to the agency or promulgating entity's overall regulatory authority.

Section 10.1-1308 of the Virginia Air Pollution Control Law (Title 10.1, Chapter 13 of the Code of Virginia) authorizes the State Air Pollution Control Board to promulgate regulations abating, controlling and prohibiting air pollution in order to protect public health and welfare. Written assurance from the Office of the Attorney General that the State Air Pollution Control Board possesses the statutory authority to promulgate the proposed regulation amendments is available upon request.

Promulgating Entity

The promulgating entity for this regulation is the State Air Pollution Control Board.

State Requirements

Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia's Clean Energy Economy," directs the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10.1-1300 et seq., and Virginia Code § 2.2-4000, et seq.:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit CO_2 from electric power facilities that:

a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of CO_2 allowances through a multi-state trading program; and

b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on CO_2 emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10.1-1308.

Additionally, on May 12, 2017, the Attorney General issued an official advisory opinion that concluded the board is legally authorized to regulate GHG: "The Board has the authority to establish a statewide cap on GHG emissions for all new and existing fossil fuel electric generating plants as a means of abating and controlling such emissions."

Purpose

Please explain the need for the regulatory change, including a description of: (1) the rationale or justification, (2) the specific reasons the regulatory change is essential to protect the health, safety or welfare of citizens, and (3) the goals of the regulatory change and the problems it's intended to solve.

The regulation is needed to control CO_2 emissions in order to protect the public's health and welfare. The proposed regulation is being developed in order to meet the direction of Governor McAuliffe's Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia's Clean Energy Economy," which states:

> There is no denying the science and the real-world evidence that climate change threatens the Commonwealth of Virginia, from our homes and businesses to our critical military installations and ports. Rising storm surges and flooding could impact as many as 420,000 properties along Virginia's coast that would require $92 billion of reconstruction costs.
>
> The challenges and costs of bolstering resilience and minimizing risk are too great for any locality to bear alone. While the impacts are significant, there are technologies in the clean energy sector that could help mitigate these impacts while simultaneously creating jobs in twenty-first century industries. The number of solar jobs in Virginia has grown by 65 percent in the last year alone, and Virginia is now the ninth fastest growing solar jobs market in the country. Revenue for clean energy businesses in Virginia has increased from $300 million in 2014 to $1.5 billion in 2016. Through state leadership, Virginia can face the threats of climate change head on and do so in a

way that makes clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio.

With these considerations in mind, I issued Executive Order 57 (EO 57) on June 28, 2016. Under EO 57, I directed the Secretary of Natural Resources to convene a work group to study and recommend methods to reduce carbon dioxide emissions from electric power facilities and grow the clean energy economy within existing state authority. The group consisted of the Secretary of Natural Resources, the Secretary of Commerce and Trade, the Director of the Virginia Department of Environmental Quality, the Director of the Virginia Department of Mines, Minerals and Energy, and the Deputy Attorney General for Commerce, Environment, and Technology. This group facilitated extensive stakeholder engagement over the last year, including six in-person meetings and a ninety-day public comment period, before compiling its recommendations and submitting a final report to me on May 12, 2017.

Among the most significant recommendations from the group is the need to develop regulations limiting the total amount of carbon dioxide emitted from electric power facilities. Given the nature of the climate change threat and the promise of clean energy solutions, I agree with this recommendation.

Accordingly, pursuant to the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10. 1-1300, et seq. and Virginia Code § 2.2-4000, et seq.:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that:

a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and

b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10. 1-1308.

Additionally, Executive Order 57 Work Group's "Report and Final Recommendations to the Governor" states that:

The Work Group received a number of presentations and written comments from stakeholders advocating for a regulation to limit carbon dioxide from power plants. These comments included recommendations that the Commonwealth join or participate in the Regional Greenhouse Gas Initiative (RGGI) or another regional trading program, that a price be put on carbon, and that Virginia strive to reduce its greenhouse gases by 30 to 40 percent by the year 2030. . . . Although many stakeholders provided feedback focused on specific in-state targets (such as 30x30), the Work Group believes that it is important and necessary that Virginia work through a regional model, like the established and successful RGGI, in order to achieve lower compliance costs and address the interstate nature of the electric grid.

The Work Group recommends that the Governor consider taking action via a regulatory process to establish a "trading-ready" carbon emissions reduction program for fossil fuel fired electric generating facilities that will enable participation in a broader, multi-state carbon market.

Substance

Please briefly identify and explain the new substantive provisions, the substantive changes to existing sections, or both. A more detailed discussion is provided in the "Detail of Changes" section below.

1. The primary purpose of the regulation is to implement a declining cap on carbon emissions. The administrative means of accomplishing this will be effected by linking Virginia to RGGI, which is an established emissions trading program. An allowance will be issued for each ton of carbon emitted by an electricity generating facility. The company must then decide if it will reduce carbon emissions and sell the resulting additional allowances, or if it will not reduce carbon emissions and make up the difference with purchased allowances. The original proposal included two options on the base budgets, 33 million tons and 34 million tons. The board selected 28 million tons, which will determine, based on a 3% annual reduction, the annual budgets and allocations for future years.

2. The mechanism for determining the cost of allowances will be a consignment auction.

3. A cost containment reserve allowance will be offered for sale at an auction for the purpose of containing the cost of CO_2 allowances in the event of higher than anticipated emission reduction costs. An emission containment reserve allowance will be withheld from sale at an auction for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.

4. Monitoring, recording, and recordkeeping requirements will be implemented to track compliance.

5. Conditional allowances will be allocated to the Department of Mines, Minerals and Energy (DMME) in order to assist the department for the abatement and control of air pollution, specifically, CO_2.

6. In conjunction with program monitoring and review, impacts specific to Virginia will be evaluated, including economic, energy and environmental impacts, and impacts on vulnerable and environmental justice communities.

Issues

Please identify the issues associated with the regulatory change, including: 1) the primary advantages and disadvantages to the public, such as individual private citizens or businesses, of implementing the new or amended provisions; 2) the primary advantages and disadvantages to the agency or the Commonwealth; and 3) other pertinent matters of interest to the regulated community, government officials, and the public. If there are no disadvantages to the public or the Commonwealth, include a specific statement to that effect.

1. Public: The primary advantage to the public would be health and welfare benefits associated with controlling carbon pollution. The program is designed to avoid any significant economic impacts.

2. Department: No significant advantages or disadvantages to the department have been identified. There may be a minor impact in terms of administering a new program.

Requirements More Restrictive than Federal

Please identify and describe any requirement of the regulatory change which is more restrictive than applicable federal requirements. Include a specific citation for each applicable federal requirement, and a rationale for the need for the more restrictive requirements. If there are no applicable federal

requirements, or no requirements that exceed applicable federal requirements, include a specific statement to that effect.

There are no applicable federal requirements. DEQ notified the Senate Agriculture, Conservation and Natural Resources Committee, the Senate Commerce and Labor Committee, the House of Delegates Agriculture, Chesapeake and Natural Resources Committee, and House of Delegates Commerce and Labor Committee of this regulatory action in November 2017.

Agencies, Localities, and Other Entities Particularly Affected

Please identify any other state agencies, localities, or other entities particularly affected by the regulatory change. "Particularly affected" are those that are likely to bear any identified disproportionate material impact which would not be experienced by other agencies, localities, or entities. "Locality" can refer to either local governments or the locations in the Commonwealth where the activities relevant to the regulation or regulatory change are most likely to occur. If no agency, locality, or entity is particularly affected, include a specific statement to that effect.

There is no locality that will bear any identified disproportionate material air quality impact due to the proposed regulation which would not be experienced by other localities. None of the affected sources is owned or operated by a locality, and it is the generation of electricity that is directly subject to the regulation, not its end users. The Department of Mines, Minerals and Energy (DMME) will be responsible for managing the 5% allocation set-aside required by 9VAC5-140-6430.

Economic Impact

Pursuant to § 2.2-4007.04 of the Code of Virginia, please identify all specific economic impacts (costs and/or benefits), anticipated to result from the regulatory change. When describing a particular economic impact, specify which new requirement or change in requirement creates the anticipated economic impact. Please keep in mind that this is change versus the status quo.

Impact on State Agencies

For your agency: projected costs, savings, fees or revenues resulting from the regulatory change, including: a) fund source / fund detail; b) delineation of one-time versus on-going expenditures; and c) whether any costs or revenue loss can be absorbed within existing resources	The Joint Legislative Audit and Review Commission (JLARC) estimates that the cost to DEQ for administering the regulation and the cap and trade program would be approximately $95,000 per year to cover the salary and benefits for one staff position. The sources of department funds to carry out this regulation are the general fund and the federal trust (grant money provided by EPA under § 105 of the federal Clean Air Act or permit fees charged to affected entities under the permit program). The activities are budgeted under the following programs (codes)/subprograms (codes): Air Protection Permitting (513025); Air Protection Compliance and Enforcement (513026); Air Protection Planning and Policy (513028); and Air Protection Monitoring and Assessment (513029). The costs are expected to be ongoing, and any costs or revenue loss can be absorbed within existing resources.

For other state agencies: projected costs, savings, fees or revenues resulting from the regulatory change, including a delineation of one-time versus on-going expenditures.	JLARC estimates that the cost to DMME for administering the allowances it receives each year is approximately $105,000 to cover the salary and benefits for one staff position. The costs are expected to be ongoing.
For all agencies: Benefits the regulatory change is designed to produce.	To quote ED 11, "The challenges and costs of bolstering resilience and minimizing risk are too great for any locality to bear alone. While the impacts are significant, there are technologies in the clean energy sector that could help mitigate these impacts while simultaneously creating jobs in twenty-first century industries. The number of solar jobs in Virginia has grown by 65 percent in the last year alone, and Virginia is now the ninth fastest growing solar jobs market in the country. Revenue for clean energy businesses in Virginia has increased from $300 million in 2014 to $1.5 billion in 2016. Through state leadership, Virginia can face the threats of climate change head on and do so in a way that makes clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio." It is expected that the regulation will address the health and welfare impacts of climate change in an efficient, cost-effective manner. RGGI has successfully reduced carbon emissions with no negative economic impacts; see https://www.rggi.org/rggi_benefits. Emissions trading programs have proven to be very effective--with both traditional pollutants such as NO_X, and with more recently regulated pollutants such as CO_2--and an affiliation with RGGI will enable Virginia to quickly take advantage of a proven trading program.

Impact on Localities

Projected costs, savings, fees or revenues resulting from the regulatory change.	The projected cost of the regulation on localities is not expected to be beyond that of other affected entities. Essentially, every individual and every organized entity--whether government or private-- uses electricity, and it is the generation of that electricity that is directly subject to the regulation, not its end users. Furthermore, none of the affected sources is owned or operated by any locality.
Benefits the regulatory change is designed to produce.	See the description of benefits as described under "Impact on State Agencies."

Impact on Other Entities

Description of the individuals, businesses, or other entities likely to be affected by the regulatory change. If no other entities will be affected, include a specific statement to that	Electric power facilities with a capacity of >25 MW that operate on some form of fossil fuel (coal, natural gas) will be directly affected by the regulation.

effect.	
Agency's best estimate of the number of such entities that will be affected. Please include an estimate of the number of small businesses affected. Small business means a business entity, including its affiliates, that: a) is independently owned and operated and; b) employs fewer than 500 full-time employees or has gross annual sales of less than $6 million.	There are currently up to 31 electric power facilities with a capacity of >25 MW operated by 12 companies located throughout the state that will likely be directly affected by the regulation. None of these entities is a small business. There may be limited indirect impacts on small businesses in general as discussed in greater detail below.
All projected costs for affected individuals, businesses, or other entities resulting from the regulatory change. Please be specific and include all costs including, but not limited to: a) projected reporting, recordkeeping, and other administrative costs required for compliance by small businesses; b) specify any costs related to the development of real estate for commercial or residential purposes that are a consequence of the regulatory change; c) fees; d) purchases of equipment or services; and e) time required to comply with the requirements.	The primary purpose of the regulation is to implement a declining cap on carbon emissions. The administrative means of accomplishing this will be effected by linking Virginia to RGGI, which is an established emissions trading program. An allowance will be issued for each ton of carbon emitted by an electricity generating unit. It will then be up to the company to decide if it wants to reduce carbon emissions and sell its additional allowances, or or if it will not reduce carbon emissions and make up the difference with purchased allowances. Because there will not be a significant change to the allowance values RGGI already has in place, adding Virginia to the equation will not change compliance costs. The cost of allowances will be administratively managed by means of a consignment auction. In general, auctions have been known to decrease costs because the process is transparent (costs and prices are known), and the secondary market is not involved. Consignment auctions are revenue neutral, so the only actual cost to a facility would be the administrative cost of managing its consignment auction activities. Based on department experience with emissions trading programs and traditional auctions in the past (for example, under 9VAC5-140 for the NO_X Trading Rule, and CAIR), it is expected that these costs will be minor, unless a facility generates enough allowances to sell and realizes a profit from that sale. Generally speaking, wholesale electricity costs may go up or down depending on the price of allowances. Any impacts to residential consumers will be very small because wholesale costs are only a very small portion of a residential consumer's bill. Rates for commercial users may fluctuate more because wholesale costs are somewhat higher for commercial users, and industrial users, which pay rates close to wholesale, will experience the greatest of any potential impact. The most recent bill impact analysis on the re-proposed rule indicates that bills for all customers will slightly decrease as a result of the rule.

	It is important to note that Virginia's energy market is regulated. This means that the Virginia SCC is responsible for monitoring electric rates such that Virginia's consumers (whether businesses, institutions or individuals) are protected from any dramatic changes to the electricity market. Regardless of what business decisions the affected utilities make in the future to comply with the carbon cap, Virginia's utility structure is designed to accommodate this type of pollution control program. The RGGI program is designed to avoid dramatic fluctuations in consumer costs. Thus far, electricity rates for RGGI customers have been stable over the life of the program, and this stability is expected to continue. JLARC estimates that the fiscal impact (negative and positive) of the proposed regulation (in 2017 dollars) will be approximately $1.3 million in 2020, when the regulation would take effect, and $1.9 million in 2031. JLARC notes that the latter cost equates to approximately 1% of projected state electricity costs in 2031.
Benefits the regulatory change is designed to produce.	See the description of benefits as described under "Impact on State Agencies."

Alternatives

Please describe any viable alternatives to the regulatory change that were considered, and the rationale used by the agency to select the least burdensome or intrusive alternative that meets the essential purpose of the regulatory change. Also, include discussion of less intrusive or less costly alternatives for small businesses, as defined in § 2.2-4007.1 of the Code of Virginia, of achieving the purpose of the regulatory change.

Alternatives to the proposal are being considered by the board. The board has tentatively determined that the first alternative is appropriate, as it is the least burdensome and least intrusive alternative that fully meets the purpose of the regulatory action. The alternatives being considered by the board, along with the reasoning by which the board has rejected any of the alternatives being considered, are discussed below.

1. Amend the regulations to satisfy the provisions of the law and associated regulations and policies. This option is being selected because it meets the stated purpose of the regulatory action: to develop a carbon trading regulation in accordance with ED 11 (2017).

2. Make alternative regulatory changes to those required by the provisions of the law and associated regulations and policies. This option is not being selected because it would not meet the specific requirements of ED 11.

3. Take no action to amend the regulations and continue to not control carbon emissions via a trading program. This option is not being selected because it it would not meet the specific requirements of ED 11.

Regulatory Flexibility Analysis

Pursuant to § 2.2-4007.1B of the Code of Virginia, please describe the agency's analysis of alternative regulatory methods, consistent with health, safety, environmental, and economic welfare, that will accomplish the objectives of applicable law while minimizing the adverse impact on small business. Alternative regulatory methods include, at a minimum: 1) establishing less stringent compliance or reporting requirements; 2) establishing less stringent schedules or deadlines for compliance or reporting requirements; 3) consolidation or simplification of compliance or reporting requirements; 4) establishing performance standards for small businesses to replace design or operational standards required in the proposed regulation; and 5) the exemption of small businesses from all or any part of the requirements contained in the regulatory change.

This regulation meets the requirements of Executive Directive 11. Any less stringent compliance requirements, any delays in adopting the standards, any different compliance or reporting requirements, any substitution of performance standards, and any exemption of small businesses from these requirements will not meet the minimum requirements of ED11. Any such changes would compromise the effectiveness of the regulation in protecting the health and welfare of the public.

Public Comment

Please summarize all comments received during the public comment period following the publication of the previous stage, and provide the agency response. Ensure to include all comments submitted: including those received on Town Hall, in a public hearing, or submitted directly to the agency or board. If no comment was received, enter a specific statement to that effect.

Commenter	Comment	Agency response
1. About 155 individual commenters	General support for the proposal was expressed.	Support for the proposal is appreciated.
2. About 415 emails, cards and petition sponsored by Faith Alliance for Climate Solutions and Interfaith Power and Light; petition sponsored by Virginia Chapter of the Sierra Club, 2717 signatures	Climate disruption poses increasing threats to Virginians' public health, national security, environment and economy. Virginia has joined states, cities and counties across the country that understand all levels of government must act on climate if we are to protect our communities in light of the Trump administration's continued attacks on environmental protections. I support setting the strongest possible standard to cut Virginia emissions from power plants through participation in a carbon market. This is a critically important step toward carbon pollution reductions. I request that DEQ use its authority to adopt and implement a final standard that caps and reduces carbon pollution as rapidly as possible, beginning as soon as possible. The 2020 base year should be less than 33 million tons. Cover carbon pollution from biomass, which can be worse than energy generated by fossil fuels. Set the expectation of continued carbon reductions after 2030. Monitor implementation in order to respond to disproportionate environmental burden experienced by front-line, low-income and vulnerable communities.	Support for the proposal is appreciated. Specific issues identified by the commenters are discussed in further detail below.
3. About 550 sponsored	I am thrilled to see that the board has approved draft regulations to cap carbon emissions. Without immediate	Support for the proposal is appreciated. Specific

Commenter	Comment	Agency response
emails and Town Hall comments	and bold action, climate change will present unprecedented challenges to our coastal communities and would harm communities of color at a much higher rate than others. I support a final carbon rule that has the strongest possible cap on carbon emissions from Virginia's power plants through a carbon market. I also support supplemental legislation that would allow Virginia to invest a portion of the carbon market revenue in coastal resilience. The 2020 base year emissions cap should be between 30 and 32 million tons. The cap should cover biomass facilities, which can be worse for the climate than fossil fuel power plants. Carbon emission reductions past 2030 should be addressed. The plan should address the needs of low-income and frontline communities by establishing implementation monitoring and rapid response guidelines that can detect any instances of disproportionate environmental burdens.	issues identified by the commenters are discussed in further detail below.
4. About 45 sponsored emails and Town Hall comments	I'm writing to voice my support of a regulation that cuts carbon pollution from power plants and allows us to trade carbon allowances with other states. With no help coming from the federal level in addressing climate change, it's up to Virginia to act. By cutting carbon emissions in Virginia, we have the opportunity to protect public health and safety while creating jobs in the carbon-neutral renewable energy and energy efficiency sectors. And because we're joining a coalition of other states with carbon caps, action we take in Virginia is greater than the sum of its parts. Carbon trading also creates the opportunity to bring revenue back to the state to aid in clean energy deployment and resiliency, money we shouldn't leave on the table or gift to our utilities. I urge you to proceed with a strong regulation that shows Virginia is a leader in addressing climate change and takes its responsibility seriously.	Support for the proposal is appreciated.
5. 4 emails	I support Governor Northam's Clean Energy Virginia Initiative. To address the threat of climate change to our coast and public health, the state must reduce pollution from fossil fuel-fired power plants and expand renewable energy. The initiative calls for a 30% reduction in carbon emissions by 2030 and will enable Virginia to trade carbon allowances with 9 other states, a market-based mechanism that will bring revenue back to Virginia while also cutting harmful air pollution. That is why I urge the board to adopt the plan to fight climate change, protect health, and create economic growth.	Support for the proposal is appreciated.
6. 5 emails	I am profoundly proud Virginia is preparing an initiative to reduce carbon and other toxic pollutants from utility power plants. Yet, how Virginia implements this program is critical to its success. And I expect success. A successful plan will: improve public health, expand clean energy development, save all electric customers money and improve our state's competitiveness, protect living creatures and reduce climate change burdens on future generations of Virginians, ensure Virginia is "carbon	Support for the proposal is appreciated.

Commenter	Comment	Agency response
	trading ready," and require that baseline measures of carbon emissions be real and annual reductions be real and ambitious.	
7. Petition sponsored by Natural Resources Defense Council (NRDC), 884 signatures	I urge DEQ to put a strong limit on carbon pollution and to reduce that pollution as rapidly as possible, in a way that grows the state's renewable energy economy and reduces energy bills through energy efficiency. Virginians are ready for strong action and we--along with future generations--applaud you for stepping up on climate and support your work to finalize a strong statewide carbon rule.	Support for the proposal is appreciated.
8. Petition sponsored by Virginia League of Conservation Voters (LCV), 1551 signatures	To address the climate change that threatens our coast and public health, Virginia must reduce pollution from fossil fuel-fired power plants and expand renewable energy. Governor Northam's Clean Energy Virginia Initiative is the solution for addressing climate change while growing Virginia's economy, reducing greenhouse gas (GHG) emissions, and protecting Virginias' air. The initiative calls for a 30% reduction in carbon emissions by 2030 and will enable Virginia to trade carbon allowances with 9 other states, a market-based mechanism that will bring revenue to Virginia while cutting harmful air pollution.	Support for the proposal is appreciated.
9. Petition sponsored by Environment Virginia, 207 signatures	From dozens of smog-ridden days to rising sea levels, Virginians are feeling the impacts of climate change. Virginia needs to move forward with plans to protect our communities from climate change and follow the steps that other states have taken to cut pollution while the federal government stalls. I request that DEQ adopt the strongest possible standard to cut carbon emissions by ensuring that Virginia cuts carbon pollution as quickly and as soon as possible. The 2020 emissions cap should be between 30 and 32 million tons. This cap should mirror the cap that states in RGGI, the nation's most successful regional climate program, are taking to reduce emissions 30% by 2030. The rule should set the expectation that carbon pollution will continue to be reduced after 2030. This standard should take into account Virginia's untapped energy efficiency potential and all planned renewable energy developments in Virginia.	Support for the proposal is appreciated. Specific issues identified by the commenters are discussed in further detail below.
10. Gianluigi Ciovati	I encourage a base budget of 33 million tons, and applicability to all fossil fuel power generating units. I request DEQ to include biomass into the fossil fuel category as recent expansion of such power generating units highlighted the issues of the long timeframe required to capture the emitted CO_2 by re-forestation and that, in order to meet increasing demand, not all the material used to make the fuel comes from waste but from an increasing fraction is coming from tree logging. The regulation should result in a greater economic benefit than cost: energy efficiency is the lowest cost resource to reduce CO_2 pollution while meeting energy demand. Dominion ranks 50th in efficiency efforts among the 51 largest electric utilities in the nation. Strong	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.

Commenter	Comment	Agency response
	energy efficiency policies would result in close to 40,000 new jobs by 2030. More jobs are predicted to be created by further increase in true renewable energy sources such as wind and solar. As the disruptive effects of climate change are becoming more evident, the risk and the cost of inaction on reducing CO_2 emission is too high and the regulation is a positive step in the right direction.	
11. Virginia Clean Cities (VCC)	Regulation of carbon emissions is critically important for Virginia, a coastal state with a wide distribution of energy sources. VCC is an alternative fuel vehicle coalition, working with governments at state, regional, local, and federal level with businesses and vehicle operators in an effort to reduce GHG emissions in transportation. While Virginia's largest source of CO_2 and GHGs is the transportation sector, we recognize the value of reviewing our existing electricity portfolio and working toward cleaner sources of domestic fuels. VCC strongly supports involvement in RGGI. Many RGGI states have advanced transportation projects to mitigate the significant GHGs from transportation. VCC include electric vehicles in our portfolio, as well as hydrogen, ethanol and natural gas vehicles all utilizing electricity from the grid in some manner. Further, by using cleaner domestic fuels such as biomass, natural gas, or renewable energy for Virginia's electricity, we can benefit our economy and move Virginia forward.	Support for the proposal is appreciated. Although the transportation sector is not directly addressed in this proposal, DEQ agrees that it is an important consideration in controlling carbon emissions.
12. B. Eli Fishpaw	It is a breath of fresh air that Virginia is embarking on an effort to reduce GHG from power production. Recognizing the measure of what causes climate change is essential to learning to live within the Carbon Cycle. Without active recognition that the license to emit carbon into the atmosphere must be limited, it is difficult to imagine meeting the challenge. We focus our efforts to address human caused climate change with an acceptance that excess carbon emissions (primarily CO_2) is the problem. Therefore, all solutions must have a goal of limiting carbon emissions to less than the amount that can be sequestered out of the atmosphere. Most human carbon emissions are sequestered by nature. These emissions are in the Carbon Cycle. Under a Net Zero Carbon Emissions Economy, human emissions would equal the amount that can be sequestered. At this level, we stop adding CO_2 concentration to the atmosphere. However, we are not reducing the CO_2 concentration either. When our emissions are higher than what nature can sequester, the over emissions are added to past years over emissions. We need to limit our emissions to less than what can be sequestered to live in the carbon cycle. This must be understood before the policies that can meet the challenge are combined with a determined effort by the public to meet this challenge. The license to emit CO_2 into the atmosphere should be shared fairly. Using the data from 2007 IPCC on natural and human emissions,	The information provided by the commenter is appreciated. The primary purpose of the regulation is to address carbon pollution via linking to RGGI in accordance with ED 11; therefore, no fee-and-dividend approach is being considered under this regulatory action.

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	to achieve net zero (balanced budget) average per person emissions need to be limited to 2.6 tons CO_2/year. This would be a "Fair Share." At this level, all emissions are sequestered to achieve a Net Zero Carbon Emissions Economy. Cap and Trade allows emissions in exchange for supporting some activity that reduces CO_2 emissions, not from net zero, but from our historically high rate of emissions. In the proposal it provides financial support for high emissions electric production to reduce their emissions through technology. The cap and trade model for pricing carbon has the advantage of functioning in the background without asking sacrifice or understanding of the individual. Getting the public to understand that there is a demand by nature to limit to the amount of carbon emissions is essential to achieving it. Existing high emissions electric generation should not be rewarded by the entitlement license to emit that they can sell by reducing. I promote a continually escalating carbon tax with a rebate for the fair share of emissions and paying people to carbon capture and permanently store in the ground. A carbon tax can be similar to that proposed by Citizens Climate Lobby that charges a fee/ton CO_2 at the source and returns that fee equally to all citizens. By creating a modest fee, financial incentives are created for reducing energy and reward the development of renewable energy. As households and businesses evaluate future investments, their spreadsheets will show that investing in improvements offers the highest rate of return. This creates economic growth in the conservation, regeneration and renewable energy sectors. However, because all fees are redistributed equally, there is no money for sequestering carbon through technology. With a tax similarly structured, with a rebate for the tax on the Fair Share, creates funding for paying people to sequester carbon and preserving existing inventories of terrestrial carbon such as mature forest. Biochar is a way of permanently capturing carbon through pyrolysis. Adding the resulting charcoal to the ground increases retention of moisture, micronutrients and microorganisms. I propose that we pay people to create biochar at half the current rate of the carbon tax. This will insure a net reduction in CO_2 for the whole process. As promising as this is, biochar is not substitute for reducing emissions.	
13. L. David Roper	Deploying wind energy and solar energy in the U.S. can supply the demand. Using time-of-day availability of solar, on-shore wind and off-shore wind power in the four U.S. time zones and reasonable values of availability, wind and solar power can closely supply the time-of-day demand for electricity. Modest battery storage can fill in the small differences between solar/wind electricity	The commenter's remarks on renewable energy are appreciated. The specific suggestions for developing renewable technologies is not directly within the purview of the board or this

Commenter	Comment	Agency response
	production and demand. John Randolph of Virginia Tech has provided the following data about the economic favorability of renewable energy: Nuclear: $148/MWh; Coal: $102/MWh; Natural-gas-combined cycle: $60/MWh; Utility solar: <$50/MWh; Wind: <$45/MWH; Efficiency: <$25/MWh; Lithium-ion batteries: $209/kWh in 2017 and expected to be $100/kWh by 2025. Virginia has moderate experience with solar farms and no experience with wind farms compared to its neighboring states. Virginia would do well to study and emulate renewable energy development in North Carolina, which has similar topology to Virginia. Virginia's coal counties could lead in this. The major fossil-fuels state of Texas is way ahead of Virginia in solar energy and wind energy. It is not wise to depend on natural gas for electricity production over the long-term. Methane leaks from drilling sites and pipelines, over a 100-year period, is 34 times more potent that CO_2 at trapping heat. Extracting and burning methane may be as potent for global warming as mining and burning coal to produce electricity depending on the amount of fugitive methane. Increase the percent of electricity generation that AEP and Dominion allow for rooftop net metering. Do not charge for transmission for net metering because local solar generation greatly reduces the need for transmission lines. In fact, the price paid for rooftop solar should be greater than the cost of grid electricity. Allow communities to create solar farms or purchase from commercial solar farms that produce a given fraction of electricity for the community. Require power companies to build or buy more solar/wind energy, build community microgrids for grid resiliency, build battery backup in microgrids for renewable-energy smoothing and grid resiliency. Virginia needs to develop offshore wind farms.	regulatory action, although DEQ agrees that they are important tools for carbon control. The commenter's concerns about methane are acknowledged; however, as the specific purpose of this regulation is to enable linking to RGGI, methane is not addressed in this regulation.
14. Rees Shearer, Energizing Renewable Growth in Holston Valley and Emory Climate Collaborative; Hannah Ingram	I am pleased and proud that Virginia is preparing an initiative to reduce carbon and other toxic pollutants from utility power plants over time. How Virginia implements this program is critical to its success. Success means improving public health, expanding clean energy employment, saving electric customers money, improving competitiveness, protecting the creatures which share this land with us, and beginning to reduce climate burdens that we have been placing on the backs of future generations. In order to achieve success, DEQ must ensure that Virginia's carbon reduction regulation is trading ready by adopting a market-based approach. Joining RGGI is the best way to make this happen. DEQ will also need to prepare to auction carbon credits, if the General Assembly refuses to join RGGI. The baseline must not be inflated, and must include large industrial boilers. The 2020 base year emissions cap should be no	Support for the proposal is appreciated. DEQ agrees that energy efficiency and renewable energy are important tools for controlling carbon pollution, and the 5% set-aside is intended for this purpose. Specific issues identified by the commenter are discussed in further detail below.

Commenter	Comment	Agency response
	more than 32 million tons and initiate meaningful and deliberate carbon pollution reductions of 3% per year. To protect our forests, the program should include biomass burning facilities. Virginia is ripe for improvements in energy efficiency and solar energy. A 2015 study determined that if Virginia reduced carbon pollution by embracing energy efficiency and clean energy, households could save a yearly average of $415. Adoption of strong customer energy efficiency improvement standards benefits all customers, but especially those with low or moderate incomes. According to the Solar Foundation's 2017 Solar Job Census, Virginia could create over 50,000 new solar energy jobs. But that's if we adopt solar-friendly policies, sufficient to meet just 10% of residential electric load over the next five years. In 2017, Virginia already boasted 3565 jobs in the solar industry - already triple that of coal mining. In southwest Virginia we desperately need clean energy jobs to replace lost coal employment. But Virginia's utilities quietly thwart pro-clean energy policies and job growth. A current example is legislation that would allow power purchase agreements to finance and install solar facilities, but the bill excludes all residential, commercial and industrial customers. Only non-profit organizations would benefit. We have the resources to make clean energy bloom in southwest Virginia--a ready workforce of trained solar technicians graduating from our community colleges and a healthy number of experienced building contractors; developable unreclaimed mine lands and rural electric infrastructure orphaned by the coal industry; and communities accustomed to living alongside the energy industry. These resources offer prime opportunity for both dispersed and utility-scale solar development and employment right here. Systematically cutting carbon pollution cuts toxic pollutants from electric generating stations as well, offering a dividend in public health improvements. Enhanced public health makes the case for a program of utility carbon reductions by itself. A healthy carbon-cutting program also keeps physically vulnerable Virginians healthy. A strong carbon reduction program for Virginia, shows that we are doing our part to slow the ravages of sea level rise, storm volume and intensity, drought, heat wave, habitat loss, and disease spread, all of which are the marks of a changing climate.	
15. Pam Clough, Environment Virginia	I am concerned about climate change because it threatens our environment and health. My family and friends have experienced extreme weather events that were likely made worse by climate change. Though this is a national and global problem, change starts at home. I support setting the strongest possible standard to cut	Support for the proposal is appreciated. The commenter's concerns about climate change and discussion of the health benefits of RGGI are well

Commenter	Comment	Agency response
	Virginia emissions from power plants and join RGGI, the most successful regional climate and clean energy program in the country. We can work across party lines to cut pollution and protect our climate while the federal government stalls on climate action. RGGI states have seen pollution decrease by half since 2005 and consumers have saved over $773 million on their energy bills. I request that DEQ adopt and implement a final standard that cuts carbon pollution as quickly and as soon as possible. The 2020 base year cap should be 30-32 million tons with a baseline at the lower end of that range. The cap trajectory should parallel the model that other states in RGGI have implemented to reduce emissions 30% by 2030. The cap should incorporate all planned renewable energy developments in Virginia. The program should set the expectation of continued annual carbon pollution reductions after 2030. Virginia's baseline should also account for the state's untapped energy efficiency potential and incorporate savings that can reasonably be achieved between now and 2020. The American Council for an Energy Efficient Economy ranked Virginia 29th in its most recent State Energy Efficiency Scorecard, placing Virginia well behind all of the RGGI states. Global warming is exacerbating pollution and harming our health. In 2015 Roanoke residents breathed elevated levels of smog pollution 31 days out the year. Residents in the RGGI states are living longer and healthier lives thanks to cleaner air. The program is estimated to have saved 600 lives and prevented 9,000 asthma attacks in 6 years. An Abt Associates report shows that Virginia has already secured $380 million worth of health benefits because pollution across the region has gone down. Virginia's participation would significantly reduce pollution even further, accelerating the health benefits we have already seen.	taken. Specific issues identified by the commenter are discussed in further detail below.
16. Drema Khraibani, Hannah Funk, Lindsey Mendelson; Environment Virginia	Climate change poses increasing threats to Virginians' environment and health. In 2015 residents of northern Virginia breathed elevated levels of smog pollution 99 days out the year. Smoggy skies are expected to grow worse as temperatures rise. This means that we can anticipate more code red days and asthma attacks. The blacklegged tick that can transmit Lyme disease is expanding its presence in Virginia and reported cases of Lyme disease are on the rise. As noted in the Executive Directive, rising storm surges and flooding could impact as many as 420,000 properties along Virginia's coast that would require $92 billion of reconstruction costs. These health concerns can be prevented if we join RGGI. Residents in the 9 member states are living longer and healthier lives thanks to less pollution and cleaner air. The program has been estimated to have	Support for the proposal is appreciated. The commenter's concerns about health issues are well taken. Specific issues identified by the commenter are discussed in further detail below.

Commenter	Comment	Agency response
	saved 600 lives and prevented 9,000 asthma attacks in just 6 years. Because of the health benefits and the many climate impacts this program can provide our state, the strongest possible standard should be set to cut Virginia emissions from power plants and join the region's market of capping and reducing emissions. I implore you to set the 2020 base year emissions cap to be 30-32 million tons with a baseline at the lower end of that range. This cap should mirror the cap that states in RGGI are taking to reduce emissions 30% by 2030. The rule should set the expectation that carbon pollution will continue to be reduced after 2030, and take into account Virginia's untapped energy efficiency potential and all planned renewable energy developments in Virginia. If Virginia links with RGGI, it would be tied to the most successful regional climate and clean energy program in the country. As we have seen across northeast and mid-Atlantic states, we can work together across party lines to cut pollution, clean our air, and protect our climate while the federal government stalls on climate action. RGGI states have seen their pollution decrease in half since 2005, generated $2.7 billion in revenue, and saved consumers $773 million on the energy bills by directly auctioning their emissions. If Virginia follows a similar model it would generate $2 billion that it could use for clean energy, energy efficiency, and coastal resilience programs.	
17. Dr. Kathleen Price and Dr. Samantha Ahdoot, Virginia Clinicians for Climate Action	Patients with Lyme disease suffer from pain and inflammation in their joints, facial nerve palsies, heart arrhythmias, and chronic fatigue. Sometimes even with antibiotics, they do not recover completely. Warmer winters and earlier springs create favorable environments for tick and mosquito survival, reproduction and disease transmission. As a result, tick-borne infections across the country are soaring, including in Virginia. Between 2006-16, cases of Lyme disease increased in Virginia over 3 fold. Other tick-borne illnesses have increased, including Rocky Mountain Spotted Fever. Mosquito-borne illnesses such as West Nile Virus, and possibly Zika in the future are a threat as well. February 2017 was the warmest February on record for our state. In 2018 we had dramatic temperature anomalies, with numerous days reaching 60-80 degrees. Early onset of spring warmth causes many trees and flowers to start blooming earlier and brings earlier onset to the allergy and asthma season. According to pollen count data, the tree pollen season in Richmond is now peaking one week earlier than it did in the 1980s and the peak tree pollen count is now over 50% higher. CO_2 acts as a fertilizer that makes many plants produce more	Support for the proposal is appreciated. The commenter's observations about health issues are well taken. Specific issues identified by the commenter are discussed in further detail below.

Commenter	Comment	Agency response
	pollen. Higher tree pollen increases ER and urgent care visits for allergies. As a result of decreasing air pollution, RGGI states have prevented up to 800 premature deaths and 390 non-fatal heart attacks. Policy that protects our air protects our health, and saves the public and the government money that otherwise goes to healthcare. RGGI states have avoided between $3-8 Billion in health effects costs. By participating in RGGI, Virginia can reduce the carbon pollution that is causing these changes in our climate, natural world and health. RGGI would also enable Virginia to reduce other air pollutants that threaten public health. As a result of decreased particulate matter, RGGI states have prevented 8000-9000 asthma attacks, over 200 asthma ER visits and 400-500 cases of acute bronchitis. I support the strongest possible standard to cut carbon emissions through participation in a carbon market. I ask DEQ to use its authority to adopt and implement a standard that caps and reduces carbon pollution as fast as possible. The 2020 cap should be between 30-32 million tons. The cap should include carbon pollution from biomass facilities which can be more climate-polluting than fossil fuel power. DEQ should monitor implementation so that it can rectify instances of communities being disproportionally affected by pollution.	
18. Dr. Douglas Hendren, Physicians for Social Responsibility	RGGI makes good medical sense as well as business sense for Virginians. Sourcing our energy from dirty sources carries very high costs. Abt Associates has analyzed the public health impacts of RGGI over a 5-year period, finding hundreds of avoided premature adult deaths, hundreds of avoided heart attacks, thousands of avoided asthmatic episodes, hundreds of emergency room visits and hospital admissions, tens of thousands of lost work days, and savings of $3-8.3 billion. Fossil-fuel energy imposes many hidden costs on Virginians. It shortens our lives and sickens our children. It fouls our air, congests our emergency rooms and raises our medical bills. Changes in the atmosphere have brought higher oceans and violent storms threatening coastal cities. The cost to the U.S. of extreme weather events in 2017 came to $306 billion. Virginians cannot afford to be held hostage by the fossil-fuel sector and their political operatives. It is time to make policy decisions based on scientific assessment and common sense. I support setting the strongest possible standards for cutting Virginia emissions, including an initial cap of 30 million tons, with periodic downward adjustment; continuation of the program after 2030, unless superseded by a carbon tax; no exclusion for biomass plants; and no exclusion for methane. Natural gas is worse for our health and for global warming than burning coal. Nearly all of our	Support for the proposal is appreciated. The commenter's observations about health issues are well taken. The commenter's concerns about methane are acknowledged; however, as the specific purpose of this regulation is to enable linking to RGGI, methane is not addressed in this regulation. Specific issues identified by the commenter are discussed in further detail below.

Commenter	Comment	Agency response
	natural gas is obtained by fracking, which virtually all independent studies have found is associated with a greater than 5% rate of fugitive methane emissions. This makes gas worse than coal with regard to GHG emissions.	
19. Roy Hoagland	Referencing Virginia Clinicians for Climate Action information: Clinicians across the state support linking with RGGI. ED 11 will help protect the health of Virginias while also saving money for the state and taxpayers. Summary of cumulative RGGI health benefits, 2009-2014, avoided health effects: 300-830 premature adult deaths, 35-390 non-fatal heart attacks, 420-510 cases of acute bronchitis, 8200-9900 asthma exacerbations, 13,000-16,000 respiratory symptoms, 180-220 hospital admissions, 200-230 asthma ER visits, 39,000-47,000 lost work days, 240,000-280,000 days of minor restricted activity. Value of avoided health effects between $3-$8.3 billion.	The information provided by the commenter is acknowledged.
20. Deborah Kushner	I'm proud to celebrate Virginia's position as the first southern state to consider joining the RGGI. Not only would overall pollution levels decline, but new clean energy jobs would help the labor sector and we would have a new funding source for energy improvements and assistance for low-income customers. Joining RGGI means the road map for Virginia is already in place. RGGI has proven successful in cutting emissions without costing too much. Emissions from power plants in RGGI states fell 5% from 2015 to 2016, and have fallen 40% from 2008, when the initiative began. I urge DEQ to adopt a much lower cap than the 33-34 million that's proposed. We need to clean air quickly, and Virginia's emissions are already very close to the 33-34 figure. All sources of carbon emissions should be included in calculations. Biomass should be included, since 3 coal powered power plants have already been converted to burn wood, and we cannot afford to have others follow suit. Our forests are being harvested at an alarming rate to produce wood pellets and shipped overseas. The Partnership for Policy Integrity calls biomass "the new coal." Wood burning power plants are estimated to put 50% more carbon into the atmosphere than coal burning plants, per megawatt hour. Wood is not carbon neutral, since regrowing forests is anything but quick. Additionally, the plan should continue past 2030.	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.
21. Michael Keegan	The plan should cap and reduce carbon pollution as rapidly as possible, beginning as soon as possible. We are already way behind where we need to be. Based on starting as quickly as possible, the base year should be 2019 and the base year emissions cap should be 20 million tons. The plan should cover carbon pollution from all power plants including from biomass facilities, which can be more climate polluting than fossil fuel power plants. The plan should continue annual carbon pollution reductions in Virginia after 2030. The plan should allow for closely monitoring the implementation in order to	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.

Commenter	Comment	Agency response
	respond to instances of disproportionate environmental burdens experienced by any communities, especially low-income and vulnerable communities that have traditionally borne the brunt of pollution.	
22. Kiquanda Baker	I ask that the regulations be set at a realistic yet aggressive limit in order for these regulations to have the desired impact on GHG emissions. It is a proven fact that climate change exists and that humans are the main perpetrators. The practices that have led us to this point should be discontinued. Obviously we can't shut every fossil fuel dependent industry down, but we can cut back. The regulation is essential in pioneering the clean energy transition in Virginia. The cap should be set at least between 30-32 million tons. Biomass emissions should be included because it is a fuel source more unclean than fossil fuels. Decreasing our contribution to global warming and thermal expansion would help alleviate sea level rise in Hampton Roads while we continue to create solutions for resiliency. By embracing clean and renewable energy, Virginia can mitigate the negative impacts of burning fossil fuels while boosting the economy. With low income families and communities of color being the most vulnerable to fossil fuel pollutants and the effects of climate change, we need clean energy sources that benefit all people.	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.
23. Garry Harris, Center for Sustainable Communities	We demand healthy communities and a healthy economy, where workers receive the good-paying, family sustaining clean energy jobs, and their livelihoods are protected in the meantime. There is no reason those jobs can't grow right here, and this legislation offers a path to do so. We have worked for years to help lower income communities reduce energy burdens caused by disproportionate impacts of electricity costs and its effects on the quality of life, creating choices between food, energy, and housing adequacy. ED-11 protects the health of families and communities by curbing carbon pollution that has shown to have a direct link with enhancing climate change and is exacerbating extreme weather events. On a personal note, I have to take asthma medication on a daily basis. Implementing ED 11 will reduce harmful pollutants that contribute to dangerous smog and soot, causing heart attacks, respiratory illnesses, and even premature deaths. Virginia is the first southern state to take initiative on limiting and capping carbon pollution from fossil fuel power plants. We can take pride pushing to have energy companies take responsibility for toxic emissions that are damaging the health and environment of our communities at a time when the federal government is dismantling regulations that protect us from corporate polluters. Burning coal releases harmful toxins into the air and water, causing respiratory illnesses like asthma. RGGI states, by reducing toxic emissions and switching to cleaner energy, have	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.

Commenter	Comment	Agency response
	successfully prevents 8,200 asthma attacks and saved 300 to 830 lives, in a five year period. The starting cap should be between 30 and 32 million tons of emissions by 2020 and continued reduction of the cap beyond 2030. Another significant polluter is biomass; biomass GHG emissions are higher than those from burning fossil fuels. ED 11 contains a woody biomass loophole, which exempts woody biomass plants from the regulation. Such giveaways to industrial polluters render Virginia's program less efficient and give Dominion an unfair economic advantage. Carbon reduction plans have vast potential to reduce climate changing, harmful emissions and expand the economy. Between 2009-14, RGGI states have successfully reduced CO_2 emissions by 35% (compared to 12% in non-RGGI states) by switching from dirty fossil fuels to clean energy. Additionally, the region saw a 21.1% economic growth (compared to 18.2% in non-RGGI states). Virginia's decision to cap carbon emissions through a market-based approach offers a great opportunity to improve the livelihood and health of low-income families and communities of color who are most vulnerable to climate change and dirty fossil fuel pollutants. ED 11 should ensure that there are emission reductions in environmental justice communities and that there is a mechanism that ensures reductions of GHG co-pollutant emissions by facilities located in or near environmental justice neighborhoods.	
24. Kiquanda Baker, Garry Harris	In 2016, the number of solar jobs in Virginia increased by 65%. If the state received 10% of its power from the sun by 2023, Virginia would see over 50,400 more jobs. Virginia's coasts can support offshore wind turbines. Renewable offshore wind energy would produce clean energy and protect the coast from catastrophic oil and gas spills that threaten fish, tourism, and recreation. The wind industry could provide 1.5 times more jobs that offshore oil and gas, creating almost 14,000 offshore wind jobs and 5,000 manufacturing jobs by 2030.	The commenters' views on renewable energy are appreciated.
25. Joy Loving and Anne Nielsen, Climate Action Alliance of the Valley	Overall, this is a good regulation. It will lower Virginia's carbon emissions below what we would emit without this rule, and do it in a way that is efficient and cost effective. Virginia can reduce carbon emissions while also reducing energy costs. Linking Virginia with RGGI allows Virginia to join other RGGI states in a program with a proven track record of success in reducing carbon emissions while allowing our economy to grow. The member states of RGGI are serious about lowering their carbon emissions and would not allow Virginia to link with them if they didn't believe it would be good for them and also lower overall emissions. By linking to these RGGI states, Virginia will need to coordinate with them to	Support for the proposal is appreciated. Note that it is not possible to conduct both a consignment auction and a direct auction at the same time, and the rule will continue to implement the consignment approach while allowing for future potential participation in a conventional auction. The commenters' concerns about methane are

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	not only lower our own carbon emissions, but also to ensure that member RGGI states continue to lower their carbon emissions and maintain funding for their renewable energy and energy efficiency initiatives. Unless prohibited under Virginia law, DEQ should directly auction carbon allowances, in addition to the proposed consignment format. This approach should allow market forces to operate more effectively. Distribute allowances based on energy output, not historic carbon emissions. The initial cap should be 30-32 million tons. Allowing emissions to increase makes no sense. If allowances are given to power plants based on historic carbon emissions, it will still achieve the goal of carbon emission reductions. But it will not provide a new source of income to zero-carbon energy generators. Instead, allowances should be distributed based on updated energy output. This method gives some allowances to zero-carbon energy sources, who can sell the allowances as a new source of revenue. Do not exempt any fossil fuel power generating unit owned by and located at an individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility. Do not exempt power plants that use biofuels. The climate responds to all CO_2 molecules, regardless of their origin. Excluding biofuels would give the power industry an incentive to cut down trees to burn in power plants to avoid buying carbon allowances. Even though RGGI states exempt biofuels, Virginia has many wood-based biofuel generators. DEQ should not read the language of ED 11 too narrowly when it is clear that the impetus behind its issuance is to reduce GHG emissions. Methane, a powerful GHG about 25 times more potent than CO_2, accounts for 9% of all U.S. GHG emissions, and almost one-third of that is estimated to come from oil and gas operations. DEQ should interpret ED 11 broadly so as to bring about as much reduction in GHG pollution as possible. The fact that the other RGGI states do not include methane does not prevent Virginia from doing so. Even if exact numbers beyond 2030 are not now known, the regulation needs language that the cap will not increase going forward. Virginia's citizens, agencies and businesses need to know what to expect for their planning purposes. If the regulation leaves open the possibility that the cap will go away or be relaxed, different long-term plans would surely result. The regulation should require close monitoring of implementation to respond to instances of disproportionate environmental burdens experienced by	acknowledged; however, as the specific purpose of this regulation is to enable linking to RGGI, methane is not addressed in this regulation. Additional specific issues identified by the commenter are discussed in further detail below.

Commenter	Comment	Agency response
	any communities, particularly low-income and vulnerable communities that have traditionally borne the brunt of pollution.	
26. April Moore	The regulations will be extremely important in reining in climate-damaging emissions from fossil fuel-burning power plants. With more than 99% of climate scientists around the world warning that we must get our CO_2 emissions down. Linking Virginia to RGGI is a smart, effective way to significantly reduce GHG emissions. The cap-and-trade approach relies on the free market to do what it does well, with a minimum of government involvement. We know that a cap-and-trade approach works. The RGGI states that are using it have already reduced their power plant carbon emissions by 30% since they adopted cap-and-trade in 2008. And during that time, the economies of these states have increased faster than those of the rest of the country. RGGI states have also lowered their average electricity rates by 3.4%, while the rest of the country's rates have increased by an average of 7.2%. The regulation should include a strong incentive for forest carbon offsets. Because trees take in CO_2 during photosynthesis, they sequester carbon in wood, roots, and soil. Trees are the best technology yet discovered for carbon capture and storage. In fact, scientists rank forests as the single best climate change solution. Some cap and trade programs include forest carbon offsets as a mechanism for transferring money from fossil fuel-burning utilities to forest owners as an incentive to manage their forests for increased carbon sequestration instead of timbering. Given that 62% of Virginia is forested, Virginia should follow the example of cap-and-trade programs that include forest carbon offset credits.	Support for the proposal is appreciated. Although the RGGI model rule does offer states the option to award offset allowances for projects outside of the electric power generation sector, only a single offset project has been implemented in the entire RGGI region since the program's inception. Given the uncertainty of any benefits associated with a complex offset program, DEQ will not, at this time, implement the offset option. However, DEQ does intend to recognize offset allowances generated in other RGGI states in accordance with the RGGI Model Rule, and the proposal has been amended accordingly. The issue of whether or not to implement offsets in Virginia may be addressed in ongoing program reviews.
27. Kim Hafner	We are grateful to DEQ for taking measures to save our lives by enforcing strict regulations on carbon emissions, and by creating a cap and trade initiative which will protect the environment and public health. Legislation that will lead us toward 100% renewable, sustainable energy is our best hope. The initial base budget should be 33 million tons or less and decline 3% per year. Methane should be capped. Nothing that is being proposed is actually stringent enough based on the dangers incurred by daily carbon emissions. No fossil fuel power generating unit owned by an individual facility and located at that individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility should be exempt. DEQ should be allowed to directly auction carbon allowances in addition to the proposed consignment auction format. On our small family farm, we are working to sequester carbon by planting trees, and by perennially keeping our pasture in grass. Soil that has higher amounts of carbon as a result of such sequestration holds moisture better	The commenter's concerns about methane are acknowledged; however, as the specific purpose of this regulation is to enable linking to RGGI, methane and natural gas are not addressed in this regulation. As discussed in comment 28, for example, cap-and-trade programs in general, and RGGI in particular, are proven effective emissions reduction programs.

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	and lessens the ground's susceptibility to drought. Soil that has sequestered carbon also has green growth that helps the earth maintain lower temperatures. How might we reward farmers for farming practices which lower carbon emissions by sequestering the carbon in similar ways? It is imperative that you establish an aggressive carbon reduction program. Ideally, this would mean bypassing natural gas and all fracking extraction and transitioning directly to renewable energy. While cap and trade initiatives are positive in that they move us away from coal, they are dangerous compromises. None of us knows if the strictest regulations on carbon will be enough to mitigate the damage that we've done in time to make a significant difference, but we do know that compromises like the RGGI cap and trade, which encourages and rewards fracking, will only guarantee more suffering. In a burning building, there is no time to agree we can try buckets when all that can save us is a fire hose.	
28. Jennie Moody	For 30 years I was engaged in research tracing anthropogenic chemical signatures in the atmosphere, using observations of precipitation, aerosols, and atmospheric gases like ozone to study how pollutants are transported. Working at the University of Virginia, I evaluated the origins of sulfur and nitrogen in Charlottesville precipitation, using meteorological data and atmospheric transport models and was able to establish that higher concentrations of sulfate were associated with atmospheric transport. I am proud to think that this work, along with work I did on my Ph.D. may have contributed in some small but tangible way to the successful cap and trade program instituted by the Clean Air Act that reduced precipitation acidity by reducing atmospheric sulfates. Research published with colleagues at the University of Virginia illustrates that sulfate concentrations dropped substantially, as much as 85% from 1980 to 2009 measuring sulfate concentrations in precipitation and aerosols downwind of North America. This is simply to say, cap and trade works, we can lower emissions and their environmental impact. I support DEQ in the position of being the first southern state to formulate a program to encourage the reduction of CO_2 emissions. Since 1978 we have seen a 70 ppm concentration increase from 335 to 405 ppm. The proposal to cap carbon emissions in Virginia is a positive step toward reducing the atmospheric concentration of CO_2. Because the concentration of atmospheric methane has also been increasing, and methane contributes significantly to the aggregate GHG index, transitioning to energy sources that result in higher fugitive methane emissions are less desirable than transitioning to zero-	Support for the proposal is appreciated. DEQ agrees that emissions trading programs are a demonstrated, effective means of controlling air pollution.

Commenter	Comment	Agency response
	carbon energy sources. Despite concerns regarding methane, I support a statewide declining cap from 2020-30. Capping CO_2 from Virginia fossil-fuel fired electric generating facilities should allow for the pursuit of multiple pathways to attain lower emissions. A carbon trading market force that creates incentives for energy efficiency and development of zero-emission renewable energy sources would be a positive step forward. However, setting the baseline emission cap below 33 MT should be explored. It is important that models reflect the impact of proposed fossil fuel retirements and account for proposed renewable projects or energy efficiency gains that will be realized on or before 2020. Virginia's participation in RGGI, along with the reentry of New Jersey, means that 20% of the 50 states are creating incentives to lower CO_2 emissions. The implementation of this program should have enhanced benefits, including air quality improvements beyond CO_2 particularly to the extent that present fossil fuel generation is replaced by zero-carbon renewable sources like wind and solar.	
29. Randall Freed, Citizens Climate Lobby (CCL)	Virginia's GHG profile is like most other states, in that by far the biggest source is burning fossil fuels. The best way in the long run to reduce emissions is to introduce a carbon fee-and-dividend approach where we put a fee on carbon in fuels, and refund the money directly to households as a dividend. CCL advocates for this approach. In the short run, the most cost-effective and straightforward way to reduce our emissions is to focus on power plants. The RGGI system works--it reduces millions of tons of emissions per year without harming states' economies. Joining RGGI will provide a clear path for utilities to invest in a way that protects ratepayers and the environment. Most of the RGGI states use these revenues for energy efficiency programs or technology upgrades. The Grid Transformation and Security Act will create a structure for Dominion and Appalachian Power to invest $1 billion in efficiency programs over the next decade. It commits those utilities to make 5,000 MW in solar, wind, and grid technology upgrades, and provides a financial mechanism to recoup costs. Instead of plowing allowance money back to the utilities, let's demonstrate how a fee-and-dividend approach works, where environmental fees from sales of allowances get distributed evenly to all households. This approach, which CCL advocates for an economy-wide carbon fee and dividend, offers the best long-term solution.	Support for the proposal is appreciated. Virginia's utilities are regulated by the SCC, which ensures that ratepayers are protected. The primary purpose of the regulation is to address carbon pollution via linking to RGGI in accordance with ED 11; therefore, no fee-and-dividend approach is being considered under this regulatory action.
30. Ivy Main, Virginia Chapter of the Sierra Club	Putting Virginia on a carbon diet opens up opportunities for the growth of Virginia businesses that develop carbon-free renewable energy or that reduce energy use. The more we displace fossil fuels that emit carbon, like coal and fracked gas, the more room we make for wind	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.

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	and solar, and the more we reward energy efficiency. The timing is ideal. Solar is now the cheapest form of energy in Virginia, and offshore wind is maturing into a powerhouse industry. DEQ proposes to begin our carbon diet in 2020 from a baseline of 33-34 million tons of CO_2. That makes 3% annual reductions less difficult than if we start from a lower baseline. However, modeling suggests a more realistic baseline would be 30-32 million tons. We should use this lower baseline to send the right signal to our market participants. We don't want our utilities to bulk up on carbon between now and 2020, when our carbon diet begins. We want them to start putting healthier practices in place now, so by 2020 they have already begun shedding carbon by employing renewable energy and energy efficiency. Another way to cheat on a diet is to kid yourself about what you're consuming. Burning biomass is the empty calories of the renewable energy sector. Unlike wind and solar, biomass emits carbon pollution, more than coal. Dominion went down a blind alley with biomass, thinking it could meet renewable energy goals while burning stuff. That's bad for Virginia forests, the health of residents, the wind and solar industries and the climate. When you put CO_2 into the atmosphere by burning trees, it doesn't do the planet any good to pretend it's carbon neutral. DEQ also proposes to exclude sources of carbon pollution under 25 MW. That's consistent with RGGI, but the exclusion should minimize the incentive for generators to structure operations in a way that will use this exemption. In conclusion, I commend DEQ for developing this carbon diet, and encourage you to make it rigorous.	
31. Earle Mitchell	It is commendable that the board is addressing the problem of burning of dirty fossil fuels to generate electricity. RGGI auctions generate proceeds, which participating states are able to invest in energy and consumer benefit programs. Programs funded have included energy efficiency, clean and renewable energy, GHG abatement, and direct bill assistance. Virginia could allocate some of these proceeds directly to the southwestern part of our state to provide economic development, education and workforce training to those who have been affected by the decline of coal production. Since RGGI started those participating have realized $ 2.3 Billon in lifetime energy bill savings, 9 million MWh of electricity use avoided and 5.3 million tons of CO_2 emissions avoided. Through 2015, $40.4 million has been returned to consumers through rebates. Rather than suppressing economic growth the participating states have outpaced the remainder of the U.S. during the time that RGGI has been operating. RGGI provides technical and administrative services to all participating states; it is a non-profit organization.	Support for the proposal and the commenter's discussion of RGGI are appreciated. Specific disproportionately affected community issues are discussed in the response to comment 55.

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	There is no glory in re-inventing the wheel when other states have already done much research and have come up with a workable, cost effective system that will clean the air and add good paying jobs at the same time. We in Virginia have already embraced a cooperative structure in that we belong to the PJM system. The function of PJM is to coordinate the movement of wholesale electricity in 13 states. Note the similarity of PJM and RGGI: two organizations working for the common good of the participants. From a humanitarian standpoint we need to confront a truth that has not been adequately addressed. The Journal of the American Medical Association published a report which states that miners working in the Appalachian coal country are now experiencing the highest levels of black lung disease that have ever been reported. We need to phase out coal as soon as possible.	
32. 301 emails sponsored by the National Wildlife Federation	Thank you for taking steps to create a new carbon market in our state with the potential to link to RGGI and make Virginia a national leader in confronting the threat of a changing climate. Virginia communities and wildlife are already on the frontlines of a changing climate, and impacts like extreme weather and sea level rise are only expected to get worse, unless we act now. Wildlife like the Carolina northern flying squirrel need your help. This endangered species is now living on "sky-islands" on nine isolated mountain peaks in the southern Appalachians. The impacts of a changing climate threaten this special species' last remaining strongholds in the state. CO_2 pollution is the leading cause of climate change, which is already fueling phenomena like massive storms, floods, and megafires. It is critical that we reduce this pollution as quickly as possible. By creating a carbon market and linking to RGGI, we can use a proven, effective market-based solution to reduce carbon pollution from the power sector while generating revenue at the same time. This revenue can then be invested in additional climate solutions such as energy efficiency measures and renewable energy. My family, our wildlife, and our environment desperately need effective solutions from the growing threat of climate change. It is your duty to protect us, so please do everything you can to make our state a leader in climate action and carbon markets.	Support for the proposal is appreciated. The commenters' concerns are well taken.
33. Tyler Privott	I am in favor of passing this regulation. However, I wanted to point out some information that the DEQ failed to utilize in their models when coming up with a cap of 33-34 million tons. This information, if implemented, would further reduce the proposed cap below 33 million tons. To start, the models did not accurately depict the amount of current solar power and amount of future solar power used in Virginia. The state already has more than 360 MW of solar power, even though the model used a	Modeling is a decisionmaking tool that captures a set of information at a certain point in time. Assumptions and inputs that are used to develop a model can vary infinitely; therefore, it is important that every effort

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	current estimate of 274 MW. In addition, the model used to calculate a reasonable cap had an extremely slow growth rate for solar energy in Virginia; however, the amount of solar energy in queue for the next few years will increase the total output by at least 1000 MW, including a 500 MW plant that is being built in Spotsylvania. In addition, DEQ assumes a growth rate in electricity demand of 1.9-3%, but the expected demand growth over the next 15 years is only roughly 1%. Also, DEQ is using information that power plant CO_2 emissions have been overall increasing since 2012. 2012 was an anomaly in terms of weather, with a relatively warm winter and cool summer, which means the overall energy consumption would be low compared to other years; therefore, the total power plant CO_2 emissions would be lower relative to neighboring years. Virginia has also reduced the amount of electricity imports from other states by creating more power plants in the state; because of this, Virginia is now responsible for these emissions since the electricity was made in-state versus out-of-state, which would result in skewed data and growth. Either new models should be created or the regulation should include a lower cap than 33 million tons.	be made to make them as reasonable and accurate as possible for the time period under consideration. In order to accomplish this goal, DEQ availed itself of modeling expertise provided by the Georgetown Climate Center. The assumptions provided by DEQ were based on reference cases obtained directly from RGGI, coupled with adjustments made for specific Virginia circumstances. The load growth and renewable energy projections provided were the best available information at the time the models were developed. Since the regulatory action was initiated, other modeling and forecasting exercises have been undertaken by a variety of parties, including DEQ, using updated data. It is important to note that the implementation of the 2018 Grid Transformation and Security Act (see response to comment 51) was one of several factors pointing to the need for additional modeling based on new circumstances. 28 million tons has been chosen for the base year cap based on new modeling data performed for DEQ by the Georgetown Climate Center as well as public input; see response to 37 for additional detail. Given the fluid nature of modeling, it is important to note that additional modeling will be performed by RGGI in concert with

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		Virginia as the program progresses in order to assure that the program is operating properly and meeting its goals. Virginia also has the capability to conduct modeling at any time if needed.
34. Mike Sandler, Carbon Share	It is society's responsibility to pass along a livable planet to the next generation. Climate change is a dangerous threat to health, the environment, agriculture, the economy, and national security. Auctioning is important because we have seen in other carbon trading programs the tendency to overallocate permits, leaving the price at the minimum. In RGGI's case, power plants switched from coal to natural gas, leaving the program overallocated and the permit price at $2/ton. In the next 10 years, solar and battery storage will undercut the business as usual case, and make current baselines obsolete. This can be partially remedied with an escalating price floor on the permit price (what California did), but auctioning 100% of permits is better because it lets the market determine the impact of innovation on the permit price. DEQ should study how a "consigned auction" differs from a non-consigned auction. Is the purpose of the consignment to protect the companies from the price signal? A climate dividend is important. Some environmental groups would prefer revenues to be used to invest in solar and wind technologies. But this is the people's money. If companies are going to have to buy permits to pollute, that money belongs to all of us. An equal per capita dividend addresses the regressive impacts of the carbon price on low-income households, and encourages support for the program. In an age of economic inequality, a climate dividend could unify the public to fight climate change. A climate dividend could become part of a basic income, addressing unemployment and social justice aspects. In addition to a price floor on permits, DEQ should consider limiting or banning offsets. There should be no exemption for onsite fossil fuel plants. Virginia should adopt its own cap and rules before joining RGGI. Once in RGGI, it may be difficult to change. I have heard that many RGGI states would prefer a tighter cap but are unable to get consensus. Virginia’s cap should be less than 33 million tons. Virginia should look at an economy-wide cap, not just on the electricity sector. A good first step would be joining the Transportation and Climate Initiative (TCI). Finally, the Department of Mines, Minerals and Energy should change its name to the Department of Sustainable Energy.	Support for the proposal is appreciated. The primary purpose of the regulation is to address carbon pollution via linking to RGGI in accordance with ED 11; therefore, no fee-and-dividend approach is being considered under this regulatory action. See the response to comment 65 for a discussion of the industrial exemption. As discussed in the response to comment 26, DEQ will not implement the offset option although offset allowances from other RGGI states will be recognized. See the response to comment 37 for a discussion of the cap.

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35. Mark Belleville	I am a professor at the Appalachian School of Law, and I teach energy related courses. I strongly support efforts to create an trading-ready GHG emission reduction program for new and existing power plants, with the goal of joining RGGI. It has been 30 years since James Hansen testified before the Senate on the risks of climate change, 26 years since the UN Framework Convention on Climate Change, 11 years the Supreme Court handed down Massachusetts v. EPA, and 5 years since President Obama's Climate Action Plan and we still have no federal law or rule addressing the emission of GHGs like CO_2 and methane. Into that void, states must step. There are many ways to internalize the externalities associated with emitting GHGs; while the RGGI program may not be my first choice, it has grown to work fairly well. One of the benefits Virginia enjoys in entering RGGI at this stage is that it has some empirical data on which to judge the program's efficacy and its fit with Virginia's goals and policies. I'd like to point out some features of the RGGI program that should help inform Virginia's decision, most of which weigh in favor of joining. The serious design flaw of the RGGI program was an initial overallocation of allowances. The spread between allowances and actual emissions was exacerbated by a decrease in energy consumption caused by the economic downturn, the displacement of coal by newly available cheap natural gas, and increased renewable energy deployments. This overallocation led to floor-level prices for allowances, and the absence of a robust trading program. The allowance auctions operated as a small carbon tax, an expense that utilities and their customers barely noticed. This problem has been addressed. By retiring a number of allowances and setting new reduced cap levels, the program is in a position to effectuate behavioral changes to the tune of a 3% reduction from current levels each year going forward. While the price of allowances has risen, as it was designed to do, it is still fairly low compared to other cap-and-trade programs around the globe, and mechanisms exist to prevent it from rising too much. Even as the overallocation caused depressed allowance prices, the program has always been successful at raising revenue for the participating states. More than 90% of the allowances have been auctioned off, raising nearly $3 billion for participating states. While it is for member states to decide on how to allocate allowances and spend proceeds, all states have auctioned the bulk of their allowances and utilize the bulk of the proceeds on energy efficiency, clean and renewable energy, and direct bill assistance. Thus, even if the allowance prices were not enough to change utility behavior, these	Support for the proposal is appreciated, as is the commenter's discussion of RGGI and Virginia issues. The commenter's concerns about the SCC's role in managing rates is well taken. SCC proceedings and audits are all public; this vertically integrated system is complemented by the RGGI program's open and transparent processes. All auction information is tracked and publically available. At the end of a compliance period, it will be possible to determine how many allowances were bought and sold, by whom, and at what price; based on this information one could then determine to what degree program costs are recoverable. DEQ is therefore confident that SCC's oversight role as well as the transparency of the complete process will ultimately protect Virginia's consumers.

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	expenditures have helped contribute to not-insignificant emission reductions in member states. With 39 auctions behind it, the quarterly regional auctions are mature and seem to function today with little difficulty. The RGGI program applies only to fossil-fuel fired power plants >25 MW. While I would prefer to see greater coverage for broader industry, the limited scope should provide some comfort for policy-makers worried about a broadly negative economic impact. It is possible that the cap-and-trade program could be expanded beyond fossil-fuel power plants, as this has occurred in both California and Europe. The RGGI program has built in enough safeguards to avoid the demise of affordable electricity. It allows only a limited use of offsets. But it allows increasing use of offsets if the prices for allowances reach certain levels. The program allows unlimited banking of allowances, and has a 3-year, both of which help utilities accommodate fluctuating annual electricity demands. And it has a reserve price that will now rise 2.5% per year; this helps assure that the allowances are utilities hold continue to have value. One of the most serious challenges Virginia and RGGI will face is that most of the currently participating states have deregulated their electric utilities far more than Virginia has. I would focus my attention on how much the SCC will allow Dominion and APCo to pass on increased costs to its customers in the SCC-approved tariffs. I urge the rulemakers to be transparent with the public on this issue. As a rate payer, I am comfortable with a small rise in my electric rates associated with joining RGGI. But I also am aware that recent tax cuts have benefited the bottom line of both major Virginia electric utilities, and there is likely enough excess profit there to absorb the additional costs. I appreciate the Attorney General's opinion that this program is achievable under existing law. There will be serious and plausible litigation over Virginia's attempt to effectuate this change without the General Assembly's involvement. The General Assembly will need to pass legislation to determine how allowances are allocated and revenue spent. For this reason, I would urge DEQ and other involved agencies, as well as our delegates and senators, to work to provide explicit approval for this proposal. State leaders must be clear-eyed as to the sea-level and storm-surge threats facing Norfolk/Hampton Roads, including the naval base and export facilities. Hurricanes affecting mid-Atlantic states will continue to grow in frequency and intensity. Studies suggest degradation	

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	and loss of economic value to the Chesapeake Bay, and loss of fish stock and forest productivity. While climate change is a global problem, self-interest and self-preservation should also motivate the state to reduce its emissions. This is a very good proposal, and I strongly support it.	
36. Coleman Dickerson	This regulation needs to be put in place, but not without some changes to the modeling process and general process of assumptions. The proposal grossly overestimates the projected growth in Virginia's future electricity consumption. This overestimation results from neglecting the strides the state has been making in increasing solar power, and neglecting the reduction of increasing electricity demand given a weakening stream of electricity imports. I insist that the projections for Virginia's future electricity demand be re-modeled and realistic expectations for this growth replace the 1.5% - 3% estimation given in the current report. Updating the models with more relevant and accurate information would support the 33 million ton cap versus the 34 million ton cap. Setting the cap at 33 million tons would provide a more accurate goal for the front end of this regulation's time allotment. Reaching the estimations for our 2030 cap is more feasible when the range between starting goal and ending goal is decreased.	See the response to comment 33 for a discussion of DEQ's modeling efforts and the response to comment 37 for further discussion of how the final cap was established.
37. Victoria Glasgow	While it is a step toward responsible GHG management, the proposed cap is higher than what we can meet under current projections. I urge DEQ to update its baseline scenario to reflect more realistic estimates. The current cap of 33 or 34 million tons CO_2 is based on the assumption that energy demand is going to increase at a rate of 1.9% and 3% for residential/industrial and commercial development. When including solar capacity, residential/industrial demand growth is under 1% for the next 15 years. Moreover, commercial demand is growing only because of the prevalence of server farms. The energy demand of these solar farms is covered by newly-installed solar. For example, a 500 MW plant has been proposed in Spotsylvania, and Microsoft has purchased more than half of the energy it will produce. Spotsylvania's 500 MW solar farm is projected to cut 1 million tons of CO_2 per year, so why is this already-planned projection not accounted for in the cap? Additionally, Dominion has 3 new natural gas plants that will displace coal plants and result in reduced emissions: another reason to lower the cap, since the plants will be able to provide the same amount of energy with lower emissions compared to coal. If DEQ keeps its baseline emissions too high, it inflates the cost of reaching the cap. DEQ should consider including ECR as part of the cap (9VAC5-140-6210) plus output-based allocation (9VAC5-140-6215). The cap should also start in 2019 to effectuate the Executive Order as soon as possible.	As can be seen from this and many other comments, a wide range of caps has been advocated. Recommendations ranged from a low of 20 million tons per year to a high of 37.5 million. Many recommendations fell within a range of 30-32 or 33-34. It has been determined that 28 million tons is the appropriate level for a starting base budget. This initial budget will enable the reduction of CO_2 while enabling Virginia's participation in RGGI to operate smoothly and effectively. Since the regulatory action was initiated, modeling and forecasting exercises beyond the department's original modeling have been undertaken by a variety of parties using updated data. Notably, modeling by NRDC using

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		updated assumptions projects business-as-usual emissions of 28 million tons in 2020 (see comment 121), and NRDC recommended that the cap be set accordingly. As discussed elsewhere, implementation of the 2018 Grid Transformation and Security Act, which calls for significant utility energy efficiency and renewable energy initiatives from Virginia investment owned utilities, will further lower emissions beyond what was originally proposed. Additionally, new modeling was conducted with updated information on a business-as-usual basis for Virginia and the 9 RGGI states that indicated a cap of 28 million tons was achievable and reasonable; see the response to comment 33. Ultimately, the program needs a starting point, and, having reviewed the new information and considerable public input, DEQ believes that 28 million tons is a reasonable program starting point. More detail on how DEQ's modeling was performed is discussed in the response to comment 33. While DEQ expects to achieve steady emission reductions whatever the starting cap, the state also needs to balance that goal with the reality that there will always be a degree of uncertainty as to the composition and amount of emissions in the future that no model can accurately predict with certainty. Imposing a cap that is too stringent or too

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		lenient will not help Virginia reach its goals, and DEQ believes the final cap strikes the proper balance. As discussed in greater detail elsewhere, RGGI routinely undergoes comprehensive, periodic reviews to consider program successes, impacts, and design elements. Caps can be modified as needed to ensure long-term program success, not only for RGGI but in the specific interests of the Commonwealth.
38. Chris Bolgiano	I support DEQ's cap and trade proposal as at least a first step to addressing climate change. However, it is so limited in scope that Governor Northam should issue a new Executive Order and expand state authority to address certain shortcomings. The irony of facilitating gas pipelines while promoting a cap and trade program for CO_2 is not lost on us. To avoid subverting addressing climate change, CO_2 equivalents should be calculated for net emissions impact of methane by fracked gas production and transport. These methane-CO_2 equivalents must be included in the CO_2 budgets and allowances, because utilities burning coal or oil will move to gas to claim lower CO_2 emissions. A program based only on CO_2 will stimulate fracking, gas transport, and pipelines. Methane is a greater climate danger than CO_2. The Attorney General has ruled that "The Board has the authority to establish a statewide cap on GHG emissions." GHGs include methane. As Bill McKibben says, moving from coal and oil to gas is like kicking OxyContin by taking up heroin. Fossil fuel utilities should pay for the privilege of damaging our environment and Virginia should apply those revenues toward climate solutions, as RGGI does. According to DEQ staff, "Unlike a conventional auction, such as the one RGGI manages, a consignment auction is revenue neutral, and will enable Virginia to link to RGGI while staying within the bounds of Virginia law." In addition, if Virginia law prohibits the return of auction revenues to the state, or if the General Assembly must approve revenue-positive auctions, then DEQ should outline the appropriate steps to overcome these obstacles, because RGGI states gain billions of dollars from auctions which are then used for climate solutions. The single most powerful natural climate solution is	The commenter's concerns about methane are acknowledged; however, as the specific purpose of this regulation is to enable linking to RGGI, methane and natural gas are not addressed in this regulation. As discussed in the response to comment 26, offsets will not be implemented at this time. Biomass is further discussed in the response to comment 67. For a detailed explanation of how the consignment auction will operate, see comment 136.

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	forest conservation. Because trees take in CO_2 for as long as they live, which for most of the hardwoods that constitute the majority of Virginia's forests is at least four centuries, trees are the best technology for carbon capture and storage. Yet the proposal does not include forest carbon offset credits, which RGGI allows up to 3% of CO_2 emissions, and the California market allows up to 6%. Given that 62% of Virginia's land base is in forest, and most of that acreage is owned by more than 400,000 private individuals and families, this incentive would benefit all Virginians not only with climate change mitigation but also by long-term protection of water and air quality. To omit forest carbon offsets, and miss the opportunity to encourage retaining forests for the carbon they have already locked up and the amounts they would continue to sequester, would be a strategic mistake. Counting biomass as carbon neutral is another mistake. In a letter to Governor Cooper of North Carolina concerning the increase of biomass burning, more than 100 scientists stated: "Biomass plants emit more CO_2 emissions per unit of electricity than coal or gas plants. In addition, it releases harmful particulate matter and smog precursors.… Removing the CO_2 emitted from burning trees for electricity requires waiting decades to a century for trees to regrow. Forests in the U.S. South are logged at a rate four times that of South American rainforests. A 2016 study showed that logging reduced the potential of the U.S. forest carbon sink by approximately 35%. Increasing carbon sinks by way of forest conservation and restoration plays a significant role in emissions reduction." While logging residues give off CO_2 during decay, removing them for burning depletes soil by removing nutrients, degrading forest productivity including the regrowth of the trees supposed to balance emissions from burning. Whole trees are being harvested for pellets, an industry that has degraded forests in the southeast and is moving into Virginia. There is no mechanism to verify that trees regrow on site, and cutover forests are ripe for development. Even if trees do regrow on site, decades are required for such forests to capture and store as much CO_2 as was emitted by burning, and during that time CO_2 emissions will increase because trees can't grow fast enough to offset them. This proposal covers only one facility that co-fires coal and biomass but should also include the others that burn only biomass, and ideally not allow burning biomass at all.	
39. John Reeves	DEQ and the board deserve wide support for this key initiative. The evidence and science is overwhelming that anthropogenic climate change is very real. Threats to our health, economy, infrastructure, coastline and national security plus carbon pollution from burning fossil fuel is significantly contributing to ramping-up climate change and sea-level rise. Practical, market-based strategies	Support for the proposal is appreciated. See the response to comment 65 for additional discussion about the industrial exemption, and response to comment 67 for further

Commenter	Comment	Agency response
	should be optimized to improve Virginia's poor rankings on energy efficiency plus on renewable energy, especially on solar energy capacity and initiatives. Virginia should expedite steps to partner with RGGI. The legislature may also need to concur, so preparations and good findings must be available to ensure this concurrence. Many benefits await good measurement, especially lowering of wasted energy, swinging demands on power grids and peaking facilities, and cost of power bills. The regulation should include practical, market-based ways to continue CO_2 reductions after 2030. There are few justified exemptions for fossil-fueled heat and electricity generators at a factory. There may be a reasonable compromise on some exemption of blended in biomass/forestry byproducts. It seems that Virginia forestry and pulp and paper facilities can justify levels above 10% blend with fossil fuels--maybe up to 30 or 50%?	discussion of treatment of biomass.
40. Adam Brookman	We have been given a tremendous opportunity to protect our future with this carbon emissions cap. While this program is best we can hope for right now, the choice we have been presented for how many annual millions of tons of CO_2 to be released is simply appalling. I understand that in any negotiation there is a give and take for all parties involved, but why must we give away what has been taken from us for so long. To choose between 33 and 34 million tons of CO_2 is insulting and reeks of nothing but greed. The reason we have these two choices is obviously the representatives from the major power companies of Virginia. Thank you for giving your customers options. I propose a different amount. I propose that there be an annual allotment of no more than 25 million tons of CO_2 with the amount reducing by 8% each year. This goal may be aggressive but easy goals is something we do not have time for. The text of the proposal consistently refers to "fossil fuels" when discussing CO_2 reduction. While fossil fuels are one of the worst contributors of CO_2, they are not exclusive. The burning of wood or biomass produces equal if not more CO_2, so why should it be treated any different? There should be no exemption for any power producing facility on any of their units that produce CO_2 in any way shape or form. Biomass burning power generation must be held accountable for their CO_2 emissions.	See comment 37 for further discussion of the cap and comment 67 for further discussion of the treatment of biomass.
41. Maria Papadakis	I am writing to indicate my strong support for a cap-and-trade allowance system and participation in RGGI. The regulation should include opportunities for CO_2 emission offset allowances in agriculture (forest offsets and avoided methane from agricultural manure management operations). This would enable the farm sector to benefit financially from efforts to protect forests and to afforest, and from efforts to mitigate methane, a highly potent GHG. The regulation must make a provision for the voluntary renewable energy market set-aside allocation mechanism, as allowed for by RGGI. The set aside	Support for the proposal is appreciated. DEQ recognizes the value of voluntary renewable energy market; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME. Given the uncertainty of any benefits

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	enables the voluntary renewable energy market to contribute to the state's overall CO_2 mitigation goals and compliance opportunities, and are critical for the process of reducing emissions. It is also needed to avoid weakening the in-state economy for renewables. The absence of a set aside could cause Green-E to quit certifying in state green power. The Center for Resource Solutions explains that "If a cap-and-trade program is adopted and implemented without a voluntary renewable energy set-aside mechanism, Green-e may be unable to continue to certify voluntary sales of renewable energy from the state, or the additional cost of allowance retirement to the voluntary purchaser may preclude certified sales from generation in the state. This would mean that voluntary buyers in these states will get their certified renewable energy from outside of the state in the future. A voluntary renewable energy set-aside will allow for this demand to be met by resources in the state--allowing your state the opportunity to maintain the private investment dollars that may otherwise go elsewhere."	associated with a complex offset program, DEQ is not, at this time, proposing to implement offsets; see the response to comment 26. See comment 51 for further discussion of the set-aside.
42. William M. Shobe, University of Virginia	Output-based updating of allocations is appropriate and prevents emission leakage. Model runs show that output-based updating of allowance allocations helps reduce leakage while retaining incentives to shift generation away from high-emitting sources. Free allocation of allowances acts as an implicit subsidy for the generation of electricity by granting to ratepayers the market value of the stream of allowances. Generators take this grant into account when calculating their marginal cost of generation and so can maintain relative competitiveness with the generators in the rest of the PJM region. This prevents generation from migrating out of Virginia and into the uncapped portions of PJM. Output-based allocation seems the appropriate choice given the potential for leakage of emissions into the rest of PJM. The consignment auction improves efficiency and fairness. By enhancing liquidity in the auction, requiring consignment probably improves price discovery in the RGGI market. The act of consignment and the resulting requirement that Virginia utilities purchase back what they need may make allowance prices more salient to market players and the generators. Consignment auctions monetize the value of the grant of allowances to the generators--they establish a clear market value of the grant. This allows the SCC to establish whether allowance value is being transferred to ratepayers rather than being retained by generators. Given the value of the free grant of allowances, it is critical that ratepayers be protected from generators pocketing the value of allowances. The consignment auction helps make this possible. The ECR helps correct over-allocation. In every emission	See the response to comment 33 for a discussion of modeling, and the response to comment 37 for discussion of the cap. The commenter correctly notes that carbon intensity is decreasing.

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	market established to date, allowances have been over-allocated at first. In the case of RGGI, the cap has been reduced dramatically due to the initial over-allocation. Even after the initial allocation, costs often fall faster than the cap leading to lower than expected allowance prices. The proposed rule continues this pattern of over-allocation, since DEQ has set the initial cap too high. This makes the ECR an important backup mechanism for ensuring that emission reductions will be greater, if the costs of achieving those reductions fall below expectations. The initial cap should be 30 to 31 million tons. DEQ has overestimated business-as-usual emissions over the next 15 years. This makes achieving the reductions for a given cap level appear more expensive than they really are. DEQ's analysis is not off by just a little, it is grossly in error. The agency has provided an analysis that is inconsistent with facts that were readily available to the agency at the time it did its analysis. What is more, the bias is clearly in one direction, overstating the emissions that would occur in the absence of this rule. This, in turn, overstates the cost of achieving a given reduction. "Reference Case 1" (RC1) assumes that Virginia will generate zero electricity with solar PV for the entire forecast horizon. This assumption is false. At the time DEQ did its analysis, Virginia had more than 100 MW of solar PV in operation with more than 250 MW under construction. By the end of 2017, Virginia had just more than 360 MW of solar PV capacity in operation. This capacity can be expected to generate approximately 720 GWh of electricity per year. In addition to the solar already in operation, the PJM interconnect queue has several gigawatts of solar PV slated for Virginia. Two years ago, Dominion had agreed to have 400 MW in place by 2020, but in April 2017 the company announced in its IRP its intention to build around 240 MW per year for the next 15 years. This estimated solar build was for Dominion's "no carbon regulation" case. APCO and ODEC had both announced that they were adding solar capacity as well. There are currently over 700 MW of Virginia solar PV capacity in the engineering and procurement stage. The PJM interconnection queue has close to 6 GW of capacity planned for Virginia in the next few years. Much of this was already on the queue when DEQ assumed zero solar build for Virginia over the next 15 years. At the time of its analysis, DEQ had reason to know that Virginia would probably have at least one GW of solar PV capacity by 2020. Yet the agency assumed in RC1 that there would be zero solar PV built in Virginia before 2031. This inflates the appropriate level of the cap. Reference Case 2 (RC2) is only marginally better; again, understating likely solar PV capacity and generation that would occur in the absence of the rule.	

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	The agency assumed that, by 2020, Virginia will have a capacity of 344 MW and will generate only 819 GWh of solar PV electricity. This is less than half of what would reasonably have been expected even before ED11 was announced. Taking the current 360 MW and adding 240 MW per year, this implies solar PV generation of about 1300-1500 GWh more per year than estimated in RC2. If the solar PV displaces half coal and half natural gas, then DEQ has overestimated CO_2 emissions by nearly 1.5 million tons per year due to underestimating solar capacity. The mistake is much greater for RC1, where solar PV is incorrectly assumed to be zero. By underestimating the amount of solar PV generation that would have occurred without the rule, DEQ has overestimated business-as-usual emissions by around 1.5 million tons/year. Both scenarios ignore already contracted capacity increases in the short run. Both of DEQ's Reference Case scenarios err by assuming unrealistic rates of growth in electricity generation. This, in turn, results in unrealistically high capacity factors for coal plants in Virginia and unrealistic growth in fossil fuel generation capacity, mostly natural gas. This further inflates expected business-as-usual emissions and is used to justify a higher cap than is necessary. In its April 2017 IRP, Dominion estimates future generation growth to be 1.3% per year. Accepting Dominion's estimate for demand growth, DEQ made a serious error in its modeling of reference case emissions by assuming unrealistically high growth rates in generation. DEQ's generation scenario for RC 1 has generation growing at an average rate of 1.9% per year and RC2 has it growing at 3.4% per year. Dominion represents 70% of generation in Virginia. The APCO region, which is the second largest in Virginia, has flat or declining demand. The remainder of the state is too small to make up the difference, but does not have growth rates higher than Dominion's. DEQ assumed a higher growth rate for generation than the electric utilities are using in their own capacity planning. This inflates the estimated need for fossil fuel combustion in future years. Dominion has over-forecast demand every year since at least 2012. Its forecasts of future generation have fallen dramatically over this same period but are still too high and will continue to fall in the next few years because of a flaw in its forecasting methodology. Generation has grown faster than demand since 2015 because of a Virginia state policy to repatriate generation and reduce imports of electricity. The process of repatriating imports is now essentially complete. Dominion is anticipating small amounts of exports over	

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	the next few years, given that it is nearing completion of 3 new natural gas generators. Now that the process of repatriating generation is complete, generation and demand will tend to grow at the same rate. Recent growth in electricity demand in Virginia has been less than 1% per year even as the state economy has grown following the last recession. Recent trends in both residential and industrial demand have been negative, that is negative growth in demand. In the industrial sector, this is due to a shift to less energy intensive industries. In the residential sector, this is due to the penetration of energy efficient technologies and improvements in the energy performance of the building shell. The one source of increase in electricity demand in Virginia in recent years has been server farms. This is a small fraction of overall electricity demand in Virginia and is already accounted for in Dominion's forecast. DEQ has no basis for its grossly overstated estimates of future demand growth in Virginia. Many firms building server farms want to cover their energy demand with renewable generation and the firms are increasingly insisting that the generation be local. Server farm demand cannot account for the growth in fossil fuel emissions assumed in DEQ's faulty analysis. DEQ's two reference cases make different assumptions about 2017 total generation: 96,786 for RC1 and 93,305 for RC2. At the time DEQ did this analysis, there was zero chance that demand would be as high as assumed in RC1, but this is consistent with the general pattern of unsupported and erroneous assumptions in its analysis. Actual generation for 2017 was 93,500 GWh. To be conservative, take the higher of the two 2017 generation estimates from DEQ's reference cases, 96,786 GWh (even though it didn't actually happen) and increase it at 1% per year. The resulting generation profile shows that DEQ's assumed generation is in excess of any reasonable expectation by 3,600 GWh per year by 2020 and 10,500 GWh by 2031. If you assume that each GWh displaces half coal and half natural gas, then each 1,000 GWh is associated with on the order of 1 million short tons of CO_2. In light of this, it is clear that DEQ's analysis has grossly overestimated BAU emissions. Combined with the solar PV analysis, the 2020 emission overestimate is on the order of 4 million tons of CO_2 per year. The assumption of half displacement of gas and half coal is somewhat conservative. Chances are that more coal dispatch will be displaced. Dominion's IRP had a BAU scenario and a scenario for operating under a cap under the Clean Power Plan. One of the major differences	

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	between these two scenarios is the retirement of significant coal capacity in 2020, when the CPP was to come into force. These coal plants were not retired under the BAU scenario. This implies that substantial reductions in coal dispatch can be anticipated under this cap, which will ultimately be tighter than what would have been true under the CPP. And coal dispatch is already falling sharply due to the addition of the new natural gas capacity. Net electricity generation from coal in Virginia fell from 15,600 GWh in 2016 to 10,110 GWh in 2017. This downward trend will continue as Dominion brings its Greensville natural gas power plant online in 2019. DEQ has failed to make a case for a cap greater than 30 million tons per year. In recent years, any increases in generation due to load growth (including repatriating imports) has been offset by reduced emission intensity of generation. Since nearly all increments to generation in Dominion's IRP are solar PV, through to the end of the 15-year planning horizon, emission intensity is bound to fall further. In its reference cases, DEQ assumes a natural gas price of $2.83 in 2017 rising to $3.95 in 2020. In April 2018, the spot price of natural gas hovered around $2.75/MMBtu. To match DEQ's assumption, natural gas prices must rise more than 30% in the next two years. And yet, the futures price for natural gas, as of April 3, 2018, is $2.70. DEQ assumed a high rate of growth in natural gas prices and plugged that assumption into its model even though it was known at the time that there was a substantial probability that the price would be lower. This adds more upward bias in the estimated business-as-usual emissions.	
43. Jonathan Miles, James Madison University	The proposal will not provide any avenues for voluntary market customers to ensure that their renewable energy purchase contributes to emissions reductions beyond the cap set by the program. All RGGI states with the exception of Delaware and California have implemented voluntary renewable energy set-aside mechanisms. Without the set-aside, Virginia generation would be ineligible for participation in the Green-e Energy market, meaning that regional voluntary market customers would have to invest in renewable energy in nearby states in order to have the renewable energy certified. This would benefit neighboring states and discourage increased investment in renewable energy in Virginia. The set-aside mechanism is important to continue to stimulate private investment in renewable energy in Virginia, which in turn will promote local jobs and businesses, and further reduce GHG emissions generated in the state. I strongly encourage the inclusion of the voluntary renewable energy market set-aside allocation mechanism from Section XX-5.3(l) of the RGGI Model Rule.	DEQ recognizes the value of voluntary renewable energy market; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME. See comment 51 for further discussion.

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44. Christina Luman-Bailey, City Council of Hopewell, Virginia and Chair, GoGreen Virginia	I am concerned that the industry exemption barely passed; although I agree that all major carbon emitters should be held accountable, it is typically the coal-burning utilities sector which is the biggest offender and has a monopoly on the customer market, whereas industry must face more competition and may need more flexibility re cost of production in order to compete in the private sector. The threshold of 90% biomass in order to claim carbon-neutral seems unreasonable. Basing the credit for carbon neutral on the percentage of biomass makes for a more reasonable, scientifically-based formula and is fair. I am glad to see the DEQ moving forward with air pollution controls, but I think that a more reasonable, scientifically-based proposal will be more accepted by all and therefore more successful.	See comment 67 for further discussion of how biomass will be addressed.
45. Mayor Tom Sibold, City of Covington; James H. Hudson, III, Mayor, Town of West Point; William Hodges, Chairman, King William County Board of Supervisors	The WestRock Paper mill in Covington is a significant economic driver for our community providing over 1000 jobs and supporting over $200,000,000 in local investment through supplier purchases, payroll, and taxes every year. If care is not taken, the proposed regulation could have a serious and negative impact on the mill. The West Point Paper Mill has been an important economic driver for the Town of West Point and the broader region for over 100 years. Today, the Mill employs roughly 500 people in good paying jobs. The Mill is the largest taxpayer in the Town of West Point (and one of the largest in King William County), and contributes over $100,000,000 to the regional economy every year. Papermaking is an energy intensive and trade exposed industry, and the mill operates in an intensely competitive business environment. The West Point Paper Mill is of critical importance to King William County. The mill is one of the largest employers, one of the largest taxpayers, and one of the most significant corporate members of the community. The hundreds of jobs that the mill provides, the hundreds more that it supports, and the millions of dollars that it injects into the local economy are irreplaceable. Simply put, the mill is the lifeblood of King William County. DEQ should take great care in crafting the final regulation to ensure the mills are not placed at a competitive disadvantage. Specifically, the regulation should: 1) Maintain the existing exemption for industrial generation. 2) Fully recognize the carbon neutrality of biomass by amending the regulation to allow for the subtraction of biogenic emissions from any covered source. This is an approach that is consistent with established science and the existing RGGI program. 3) Preserve the free allocation of carbon allowances currently in the regulation, as a full auction of allowances could significantly increase the financial impact to	The commenters' concerns are well taken. The cap-and-trade program has been designed to meet the goal of reducing carbon pollution--which will be beneficial to the manufacturing sector--while protecting the economy. Industrial generation and biomass are discussed in greater detail in responses to comments 65 and 67. DEQ agrees that free allocation of allowances is integral in ensuring the smooth function of the consignment auction.

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	energy-intensive industries.	
46. Virginia Solar Energy Development and Energy Storage Authority	The Authority was established to 1) facilitate, coordinate, and support the development of the solar energy and energy storage industries and storage projects through programs that increase the availability of financing for solar energy and energy storage projects; 2) facilitate the increase of solar energy generation systems and energy storage projects on public and private sector facilities; 3) promote the growth of the Virginia solar and energy storage industries; 4) provide a hub for collaboration between entities, public and private, to partner on solar energy and energy storage projects; and 5) position the state as a leader in research, development, commercialization, manufacture, and deployment of energy storage technology. If carbon emitting generation is reduced, cleaner forms of power generation will become more widespread. The addition of energy storage will allow intermittent renewables to continue providing power at times when conventional generation would typically be required, leading to further carbon reductions. The Authority recommends that a portion of any proceeds resulting from the auctioning of the 5% of allowances set aside for DMME be used to advance renewable energy coupled with energy storage technologies. Legislators and the Governor, through their creation of this Authority, recognized that accelerated deployment of renewable energy and energy storage technologies will support a more robust and secure electric power grid. It will also lead to decreased carbon emissions, help grow the energy storage industry and create economic benefits for Virginia and its citizens.	DEQ recognizes the value of renewable energy coupled with energy storage technologies; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME. See comment 51 for further discussion of the set-aside.
47. About 25 individual commenters.	General opposition to the proposal was expressed.	The commenters' concerns are recognized.
48. 272 emails sponsored by Food and Water Watch	I urge you to drop plans to join RGGI, a short-sighted cap and trade program. It seeks to limit CO_2 emissions, but it incentivizes switching from coal to fracked gas, exchanging methane for CO_2. That's not progress. Implementing RGGI would ultimately mean more fracked gas and pipelines in Virginia. We don't need schemes like RGGI. For over 40 years, the Clean Air Act has succeeded by requiring each source of pollution to meet individual, technology-based emissions controls that minimize emissions without the lack of accountability that purchasing credits and offsets brings. Effectively, cap and trade programs like RGGI just set up a pay-to-pollute scheme that big polluters can take advantage of year after year.	Executive Directive 11 directs DEQ to "1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that: a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and b. Establishes abatement mechanisms providing for a corresponding level of

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		stringency to limits on carbon dioxide emissions imposed in other states with such limits." (Emphasis added.) In other words, the proposed regulation is designed to meet the Governor's mandate to control CO_2 via participation in an emissions trading program. In the absence of federal action to address climate change, Virginia is therefore taking active steps to address this pollutant--but not starting from scratch. The effectiveness of Virginia's carbon control program will be maximized by linking with the only realistically available program for controlling carbon. The control of methane emissions is indeed important; however, this specific regulatory action is not the means by which that can be accomplished. Methane is controlled elsewhere in the Regulations for the Control and Abatement of Air Pollution as appropriate, and other measures addressing methane may be addressed at a different time in accordance with the federal Clean Air Act and state law. Because the primary purpose of this regulatory action is to enable Virginia to link to the RGGI program, the regulation was drafted to adhere to the RGGI Model Rule as closely as possible within the framework of Virginia-specific administrative requirements. The commenters are

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		correct that the federal Clean Air Act has been extremely effective in reducing air pollution. Emissions trading programs, which are authorized under §§ 108, 109, 110, and 302 of the Act and implemented under 40 CFR Part 51, are part of the Clean Air Act success story. Emissions trading is a proven means of reducing air pollution; see, for example, comments 28, 113, and 136. Cap-and-trade sets a specific goal and a schedule on which the goal must be met. Clearly, linking to RGGI will ensure additional reductions in carbon pollution not only in Virginia but in the region. Joining RGGI will impose additional controls on each source of pollution beyond other individual, technology-based emissions controls. Note that RGGI specifically addresses CO_2, not methane. RGGI issued the "CO_2 Emissions from Electric Generation and Imports in the Regional Greenhouse Gas Initiative: 2015 Monitoring Report" on April 27, 2018. This market analysis summarizes data from 2005-15 for electricity generation, net electricity imports, and related CO_2 emissions for the participating states. It demonstrates that carbon emissions in the RGGI are decreasing in intensity; essentially, carbon intensity is being decoupled from electricity generation.
49. Elizabeth Struthers Malbon	It appears that the decision to participate in a CO_2 cap and trade program has already been made by the board, the so-called DEQ, Governor Northam, former Governor McAuliffe, or Dominion. The sad thing is that distinctions	See response to comment 48. As discussed in comments 28, 113, 136 and elsewhere, cap and

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	between these individuals and agencies may be distinctions without a difference. No one can expect the citizens of Virginia to trust these individuals and agencies given their support for pipelines. The evidence for the decision having been made is in the public notice: "In addition to any other comments, the board seeks comment on whether the initial Virginia CO_2 Budget Trading Program base budget for 2020 should be 33 million tons or 34 million tons, and declining accordingly by 3% per year. After considering public comment, the board will make a final selection of either 33 million tons or 34 million tons." So, the public is being asked to comment on whether we want our air polluted by a huge amount or by somewhat more than a huge amount. I would like the board to think about who is pushing for this program in the first place and who will benefit from it. It is disingenuous of McAuliffe and Northam to act as if they are being responsible in thinking about the dangers of the CO_2 that Virginia's power plants are pumping into the atmosphere, hastening global warming with its sea-level rise and extreme weather events. Participating in such a systematic and continued polluting of the atmosphere might give the impression that something is being done to clean up the air or slow down global warming, but this is not the case. What is needed is regulation that would require energy companies to take real steps toward cleaner air and mitigating global warming by moving away from fossil fuels altogether and utilizing the fast-growing and less expensive technologies for solar and wind power. Such a short-sighted cap and trade program has not worked elsewhere. This program creates incentives for switching from coal to fracked gas. Methane from fracked gas is a more powerful driver of global warming than coal. Fracked gas benefits the companies that extract, transport and sell it, and a cap and trade program would pass that advantage along to power companies that burn it--and to any politicians they support. The cap is excessively high, and the price of permits is too low, allowing energy companies to buy or trade their way out of reducing emissions. Such a company could also hold their cheaply-bought allowances to offset future failures to reduce emissions. This program only addresses CO_2 emissions and ignores the impact of methane on climate change and air quality. It would allow switching from coal to fracked gas, effectively worsening climate impact while still complying with the cap and trade agreement. It hardly seems coincidental that two Virginia Governors who were supportive of or tolerant of the building of two interstate pipelines for fracked gas and one state-wide energy monopoly that supported them would now be encouraging a cap and trade program that lets burning	trade programs are proven, effective means of controlling pollution.

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	this other fossil fuel instead of coal count as environmentally responsible. Money to encourage favorable legislation and regulation has never been a problem for Dominion Energy, and clean air has never been a priority for them. However, the law requires clean air to be the board's priority. You are hardly in a position to pat yourself on the back if you allow only 33 tons of CO_2 pollution instead of 34 tons while turning a blind eye to methane pollution. For over 40 years the Clean Air Act has succeeded by requiring each source of pollution to meet individual, technology-based emissions controls. The citizens of Virginia need and want bold climate solutions that continue to do that and do not compromise the wellbeing of our communities--in terms of air quality, water quality, and overall quality of life in a world feeling the effects of global warming hastened by the use of all fossil fuels. We are not fooled by this pay-to-pollute scheme, and neither should you be.	
50. David Kuebrich	The cap-and-trade polices of RGGI, the E.U., and California have done little to reduce carbon emissions. It's important Virginia learn from the errors of these plans and do better. For example, it would likely be better to impose a flat fee on the use of fossil fuels. This approach would not be nullified by external factors such as an economic decline that kept emissions under a cap. In addition, an imposed fee provides both fossil-fuel users and consumers with predictable price increases. A cap and trade policy can easily lead to disputes, and well-lawyered and politically muscular companies such as Dominion are very savvy at winning disputes. In the past, the benefits of cap and trade have been hyped. Years later, supporters learn the promised reductions in emissions didn't pan out. But for the years between the initial glowing headlines and the later realization of meager results, many citizens and public officials feel a reduced sense of urgency to develop other policies for limiting emissions. Governor Northam may feel if he proves his green creds by creating a cap and trade program, it will then be politically feasible to approve the Atlantic Coast and Mountain Valley pipelines. If so, he's wrong. I ask that DEQ convince our Governor to create a smart plan for reducing carbon emissions and to cancel the pipelines.	See response to comment 48. As discussed in comments 28, 113, 136 and elsewhere, cap and trade programs are proven, effective means of controlling pollution. In addition, RGGI has a proven track record in reducing carbon pollution. We recognize the commenter's concern about methane from pipelines; however, that is not the subject of this regulatory action.
51. 3Degrees Inc.	3Degrees applauds Virginia's decision to implement a CO_2 Budget Trading Program and join RGGI. This will secure the state as a national climate leader, and greatly expand the scope of the regional carbon market, improving market efficiency and lowering costs of compliance across the region. The proposal does not provide an avenue for voluntary market customers to ensure that their renewable energy purchase contributes to emissions reductions beyond	DEQ recognizes the value of the voluntary renewable energy market as an important tool in reducing carbon pollution but has decided not to implement a separate voluntary renewable energy set-aside. The structure of the general 5% set-aside will

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	regulation. The Voluntary Renewable Energy Market Set-aside allows allowances to be paired with renewable energy at no added cost to the voluntary market. In order to support private investments in renewable energy, 7 RGGI states and California have implemented a renewable energy set-aside. This mechanism sets aside about 2% of the allowances and makes them available for free to be paired with voluntary renewable energy purchases. The renewable energy set-aside will lead to continued demand for Virginia generation in the voluntary market and allow the generation to be eligible for Green-e Energy certification. In addition to the avoided emissions benefit being important in private investment decisions, it is also a requirement of Green-e certification. Green-e certifies tens of millions of megawatt hours of renewable energy every year, including renewable energy generated in Virginia, and, as the only certification for the voluntary renewable energy market in the U.S., is the standard for private purchasing of renewable energy. Where states have introduced cap-and-trade regulation without a renewable energy set-aside, Green-e has required that Green-e certified renewable energy from these states be matched with purchased allowances equal to the generation's emissions reduction benefit on the grid. This adds a significant cost to renewable energy from these states, such that they generally exit the voluntary market. Where private purchase of allowances is not possible, generation from that state is ineligible for Green-e certification. Without Green-e certification, Virginia generation will be less desirable for voluntary purchasing and will lose financial support from the voluntary market. Since Virginia currently only has a RPS goal, the primary markets for Virginia renewable energy generation are adjacent state RPS or the voluntary market. The voluntary market is currently the primary way that high quality renewable energy remains in the state. Local projects risk losing voluntary market support if the renewable energy set-aside is not included. 3Degrees has worked with small-scale and residential solar and wind projects in Virginia, supporting the projects by facilitating the sale of the premium RECs for use by voluntary customers. The voluntary market is generally providing funding for projects that would not receive funding from compliance REC markets, and often providing more funding per MWh. In some cases, the projects would be not financially viable without this revenue stream. If the voluntary renewable energy set-aside is not included, there would no longer be an opportunity for 3Degrees to support projects of this kind in Virginia. We urge DEQ to encourage private capital	be under the purview of DMME, which is the appropriate state agency to implement renewable energy and energy efficiency programs. DMME may, at the appropriate time and in accordance with its regulations and policies, seek to implement a voluntary renewable energy market set-aside or its equivalent. However DMME structures the set-aside, it is important to bear in mind that energy efficiency will be an important tool in the control of carbon pollution. Energy efficiency programs reduce in-state demand, which results in the reduction of carbon pollution and the control of potential leakage. Note that renewable energy projects in Virginia should be considered in the context of the Grid Transformation and Security Act of 2018 (SB966), that: - Requires utilities to make $1.145 billion in investments in energy efficiency projects and low-income energy assistance over the next 10 years. - Authorizes the SCC to deem 5,000 MW of solar and wind energy projects to be in the public interest, paving the way for approval of new clean energy projects. - Commits Appalachian Power to make a separate investment in 200 MW of new solar capacity. - Promotes energy technology including battery storage and pumped storage in southwest Virginia. - Requires review of state

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	investing in renewable energy by including the renewable energy set-aside.	regulations that hinder clean energy development. - Creates a transparent stakeholder process to expand energy efficiency program offerings. - Creates a transparent stakeholder process to make recommendations for solar program expansion, including net metering, community solar, and siting. DEQ expects that opportunities for voluntary renewable energy projects will be encouraged as a result of this initiative.
52. 3Degrees Inc.	3Degrees encourages DEQ to allow the issuance of CO_2 emissions offsets. High-quality carbon offsets can be an important tool for a successful and economic cap-and-trade program. While offsets have not been used to date for compliance in RGGI, as the cap lowers we believe offsets will be an important tool for achieving emissions reductions cost while encouraging innovative climate solutions. Offset projects can address emissions reductions in uncapped sectors and provide other co-benefits.	Although the RGGI model rule does offer offsets, only a single offset project has been implemented in the RGGI region thus far. Given the uncertainty of any benefits associated with a complex offset program, DEQ is not, at this time, proposing to implement offsets; see response to comment 26.
53. American Council for an Energy-Efficient Economy (ACEEE)	Energy efficiency reduces emissions quickly and at a lower cost than any other CO_2 compliance option by reducing the need for power generation. State energy efficiency policies and projects can be the quickest and cheapest means to reduce generation from fossil fuel-fired power plants. Energy efficiency improves air quality and saves consumers money. It boosts local economies by creating diverse, high-quality jobs across the construction, engineering, financial, environmental, manufacturing, and industrial supply chains. In 2015, RGGI states invested 64% of allowance revenues on energy efficiency, amounting to 60% of cumulative investments. Programs funded by these investments are expected to return more than $1.3 billion in lifetime energy bill savings. Energy efficiency investments through RGGI contributed to reducing the number of premature deaths and illness in the northeast since 2009. DEQ proposes a set-aside of 5% for the control of CO_2. Given the benefits and low-cost CO_2 reductions energy efficiency provides, we recommend that all set-aside revenues be allocated to energy efficiency projects. However, current market and regulatory barriers to investment in energy efficiency can hinder its use as a compliance strategy. DEQ should consider	DEQ recognizes the value of energy efficiency as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement the set-aside. DMME may, at the appropriate time and in accordance with its regulations and policies, implement an energy efficiency set-aside as described by the commenter. The set-aside will be 5% in the early stages of the program; the set-aside may be revised at a later date as the state

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	methods for allowance distribution to address these barriers. Typically, a set-aside is a small portion of a total cap of allowances, which means that energy efficiency is treated as a resource on the margin. This is not consistent with Virginia's energy efficiency potential, nor does it make economic sense. The incentive in a market-based regulation should drive emission reductions by the lowest cost means, which in this case is energy efficiency. Instead of a set-aside, an allowance approach could preferentially award allowances to energy efficiency programs. Allowances could be allocated on an updating output basis according to kWh generated or saved. Ideally, such an approach would award allowances to zero-emission savings and generation first. The remaining allowances could go to fossil-fueled electric generators. An updating output-based allocation provides a transparent and predictable price signal, and rewards measures that deliver lasting CO_2 reductions. There is untapped potential for non-utility energy efficiency programs in Virginia over the next 10 years. The 5% set-aside does not reflect the level of potential investment in energy efficiency that the state could achieve. We recommend a set-aside of 10% in order to provide a more robust financing stream for energy efficiency projects. Increasing the set-aside would lead more cost-effective emissions reductions. Modeling indicates that increasing the set-aside would not impact rates. Energy efficiency measures also reduce overall customer bills, helping to alleviate any potential rate increases. DMME should use the set-aside to invest in energy efficiency projects that save energy and reduce utility costs for public and private sectors. While ratepayer-funded programs for residential and commercial customers in Virginia will ramp up over the next 10 years, large industrial customers will not be served by these programs. DMME can fill this gap. Technical assistance programs targeted at industrial customers can identify potential projects and guide the implementation process. We encourage DEQ to clarify that combined heat and power (CHP) and waste heat-to-power (WHP) projects are eligible for set-aside funds. Other RGGI states have used their auction revenue to support CHP deployment. DMME can leverage its experience operating the Commonwealth Energy Fund, using revenues to make loans to high growth potential early stage Virginia companies focused on energy efficiency and pollution prevention or establishing a revolving loan fund to finance energy efficiency investments at low interest	gains experience with the program and with the program DMME develops.

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	rates for other markets, including public entities, residents or businesses. Financing products could be paired with utility rebates in order to further spur investment. Revolving loan funds have several benefits. These programs are sustainable and can have considerable market impact. Virginia currently has a goal to reduce energy consumption in public buildings 15% by 2017. Through the Virginia Energy Management Program (VEMP), DMME helps state agencies, institutions of higher education, and public bodies reduce utility consumption by working with energy savings performance contractors. In parallel with VEMP, Virginia recently launched the Clean Energy Development and Services (CEDS) program to provide grants and loans for energy efficiency, renewable energy, and alternative fuel projects in state and local agencies. In spite of these efforts, the state has only met about one-third of this energy savings target. We recommend that DMME use the set-aside to expand energy efficiency offerings for public buildings, through VEMP or deeper incentives as part of CEDS.	
54. Virginia Advisory Council on Environmental Justice (ACEJ)	Many members of the environmental justice (EJ) community have been skeptical or opposed to market-based solutions to carbon reduction. Many community members believe their voices have not been heard during program implementation in other states. Concerns with carbon trading include the lack of regulation of co-pollutants, hotspots, equity of allowance allocation, and lack of public engagement. Perhaps the most central concern from an EJ perspective is that many EJ organizations prefer guaranteed emissions reductions at the source of polluting facilities in EJ communities, an outcome that market-based solutions can't guarantee directly. DEQ can structure a program with complementary policies that produce outcomes that EJ groups prefer. We urge DEQ to keep this concern at the forefront, and explore ways to carbon reduction that would achieve guaranteed emissions reductions at the source.	The commenter's concerns are acknowledged. In addition to controlling carbon pollution via this regulatory action, DEQ implements a robust permitting and compliance program to ensure that federal and state standards for controlling air pollution are met.
55. Virginia Advisory Council on Environmental Justice (ACEJ)	DEQ should formalize rules for meaningful engagement of EJ communities. The Clean Power Plan required states to demonstrate how they were meaningfully engaging low-income communities, tribal communities, and communities of color. DEQ should likewise set concrete criteria on how the state plans to engage EJ communities throughout the design and implementation of the regulation. DEQ should participate in a dialogue on allowance allocation and the identification of potential hotspots. DEQ should create a plan for sharing the results of the proximity and cumulative impact analysis to the public, including an education and outreach plan to communities that are convenient and understandable. These methods should be targeted to "meet people	Community involvement is important to all DEQ programs, and DEQ has a robust community involvement program. Effective community involvement strengthens public confidence in DEQ, and encourages those who are most concerned with agency decisions to inform and help implement them. In addition to a formal Community Development

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	where they are" in order to maximize community involvement for specific communities. A toolkit was created by community advocates in coordination with Green for All to ensure meaningful community engagement to comply with the Clean Power Plan. DEQ should use this toolkit as a guide to design its own plan for community engagement during this process. ACEJ recommends the creation of a long-term plan designed to increase participation of EJ communities. DEQ should formalize a process to gather feedback from community members affected by climate change, including creating a sustained dialogue to discuss complementary policies that may be adopted to maximize emission reductions in EJ communities. ACEJ recommends that DEQ host community forums in locations that are experiencing threats from climate change, and explain how this rule is designed to strengthen the state's commitment to fighting climate change.	Policy, DEQ is also taking the following steps as part of its strategic plan and commitment to build community involvement: - Provide opportunities for meaningful community involvement in all agency programs, and consistently look for new ways to enhance public input, and include development of education materials and training opportunities for the public. - Identify and implement steps that enable early public involvement and collaboration in significant environmental decisions. - Seek input reflecting different points of view and carefully consider this input when making decisions. - Work to ensure that decisionmaking activities are open and accessible to all interested individuals and organizations, including those with limited experience participating in environmental decision making. - Develop innovative ways to present information on the agency web site and elsewhere, and ensure that information is useful, understandable and easy to find. DEQ's EJ Coordinator has also been consulted for advice on communicating and working with vulnerable communities. The EJ Coordinator will provide this assistance on an ongoing basis as the rule is implemented. Routine RGGI program reviews will also provide the opportunity for any

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		affected community to bring attention to any issues that may arise. Linking to RGGI will make Virginia a participant in RGGI's regularly scheduled program reviews. These comprehensive, periodic reviews consider program successes, impacts, and design elements. Stakeholder meetings are held throughout the program review process in order to encourage stakeholder engagement and the submission of comments from interested parties. As part of this process, the department will evaluate how the program is working from a Virginia standpoint as well as in the context of the other RGGI states. Any issues identified with respect to affected communities may be identified and resolved as part of this exercise. In order to clarify that this review process will take place, the proposal has been modified to add a new Article 10, Program Monitoring and Review. This provision specifies that in conjunction with the CO_2 Budget Trading Program program monitoring and review process, the department will evaluate impacts of the program specific to Virginia, including economic, energy and environmental impacts, and impacts on vulnerable and environmental justice and underserved communities. The department will also develop a plan to encourage increased participation by affected

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		communities.
56. Virginia Advisory Council on Environmental Justice (ACEJ)	DEQ should complete a robust proximity and cumulative impact analysis to determine the environment and health impacts of co-pollutant emissions and pollution from sectors not subject to the carbon cap for EJ communities. Although capping carbon emissions from power facilities is the scope of the rule, we must study all major sources of carbon and other forms of pollution in Virginia when determining the full scope of environmental health effects in EJ communities. For instance, while reducing carbon from the electric sector has been a major focus of numerous advocates, the largest source of carbon pollution in Virginia is from the transportation sector. Other states in the region are launching a series of listening sessions to explore how to cut carbon from transportation while improving the equity and quality of service. Indeed, EPA has identified proximity to vehicle traffic as associated with increased exposure to toxic gases and particulate matter, which is hazardous to human health. A cumulative impact analysis from Kentucky revealed that "strong relationships between exposure related health problems and vulnerable demographics, such as poverty, educational level, and certain age groups." Similar analysis, in coordination with other state agencies and conducted with input of EJ stakeholders would help the state identify existing pollution hotspots and environmentally stressed communities so that the state can design a carbon reduction program to alleviate harms to those communities. DEQ should prioritize the perspectives and feedback of community members over industry. If hotspots are found, DEQ should create a remediation plan to reduce environmental hazards and lower pollution in environmentally stressed communities. DEQ should solicit the input of community members and other interested stakeholders for corrective remediation of past practices.	Fossil fuel-fired units are subject to a host of regulatory and permitting requirements that specifically target and control emissions of criteria pollutants and toxics. Ultimately, the control of CO_2 will reduce global warming impacts and concomitant welfare impacts on disadvantaged communities. As discussed in the response to comment 55, the opportunity to elevate specific concerns about potential problem areas will be available during routine program reviews. Note that the board's ability to address transportation sector emissions is limited by statute. DEQ believes that the monitoring and review components of the RGGI program will enable any leakage of emissions to be identified and corrected. As demonstrated in RGGI's April 2018 market analysis, carbon intensity in RGGI states is decreasing.
57. Virginia Advisory Council on Environmental Justice (ACEJ)	DEQ proposes to allocate 5% of the allowances to DMME to assist the department in abatement and control of air pollution, presumably through investments in energy efficiency and solar. Ninety-five percent of the allowances are proposed to be allocated to the polluters, which is unacceptably high. If only 5% of the allowances are directed to DMME, it must maximize opportunities to assist families and communities who've been disproportionately harmed by existing energy policy. DEQ should specify that the DMME allocation is directed toward low-income communities. In the alternative, conduct an open decisionmaking process where communities have a say in how allowances are allocated. Energy efficiency and solar energy will advance Virginia's goal to combat climate change and reduce carbon pollution. However, the state would benefit by advancing clean energy in communities who	DEQ recognizes value of directing pollution control efforts toward low-income communities; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement the set-aside. DMME may, at the appropriate time and in accordance with its regulations and policies, implement an energy efficiency set-aside for low

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	need it most. Low-income and families of all races and ethnicities pay more for utilities, which means there may be cost savings to disadvantaged communities while reducing air pollution.	income communities as described by the commenter.
58. Virginia Advisory Council on Environmental Justice (ACEJ)	Wood and other types of biomass plants release more carbon per unit of energy than coal plants, in addition to localized criteria pollutants. These plants should be fully accountable to the carbon cap and should be included in the proximity and cumulative impact pollution analysis. RGGI caps carbon on power facilities 25 MW or greater, allowing power facilities with multiple combustion turbines that individually fall below the threshold but are collectively greater than 25 MW go unchecked. DEQ should regulate these types of units holistically, and consider ways to place limits on facilities below the 25 MW threshold. New York will begin covering sub-25 MW peaker plants, a step other RGGI states can voluntarily take. EJ groups have long opposed carbon offsets on principle to not allow facilities to continue or increase pollution by avoiding localized pollution reduction. Localized pollution reduction in EJ communities is the central concern of EJ advocates with cap-and-trade programs. ACEJ supports the recommendation of several EJ organizations in the RGGI region to eliminate the use of offsets as a compliance option.	See the response to comment 67 for a discussion of biomass. To our knowledge there are no sub-25 MW peaker plants, existing or planned, in Virginia. Regardless, current state regulation (9VAC5-20-70) prohibits circumvention of air quality requirements by constructing multiple facilities in a piecemeal fashion in order to avoid regulation. As discussed in the response to comment 26, DEQ is not, at this time, proposing to implement offsets.
59. Virginia Advisory Council on Environmental Justice (ACEJ)	DEQ should coordinate with other state agencies, localities, and community organizations to study the effects of the regulation in coal-dependent communities to ensure a fair and just transition from fossil fuels to clean energy. The coalfield counties in southwest Virginia have borne disproportionate economic and environmental burdens as coal has been extracted. Virginia coalfields are now left with pollution from mining and an economy struggling to recover. Relevant state agencies should conduct an economic analysis to identify sustainable investment and other job creation opportunities for coal communities.	The commenter's concerns about coal-dependent communities in southwest Virginia are well taken; see the response to comment 55 for further discussion of how communities will be addressed.
60. AdvanSix, Greif, ODEC, Virginia Manufacturers Association (VMA)	It has been the policy of the state to avoid the imposition of regulatory requirements "which are more restrictive than applicable federal requirements" unless a showing of necessity supports a more stringent Virginia rule (VA Code 10.1-1308 A). The Administrative Process Act establishes a procedure whereby the General Assembly reviews regulations that are more restrictive than applicable federal requirements (VA Code 2.2-4014) and has the opportunity to judge whether such regulations are necessary. The board should adhere to this long-standing approach and leave any such regulation to the appropriate time and approach determined for the nation by Congress and EPA.	The board may indeed promulgate regulations in the absence of a specific federal requirement to address a state-specific need. DEQ notified the appropriate legislative committees of this regulatory action in accordance with § 10.1-1308 in November 2017.
61. AdvanSix, Greif, ODEC, Virginia Manufacturers Association	Cost-effectiveness is a fundamental premise for good regulation. When government burdens its citizens by regulation, the benefits should outweigh the burdens. The proposal fails this basic premise. The proposed regulation is not cost-effective and the cost burden far	Flexible, market-based emissions trading programs provide the most cost-effective means of reducing air pollution. The program

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(VMA)	exceeds any purported benefits. In EO-57 and ED-11, then-Governor McAuliffe revealed the non-environmental motive for mandating a CO_2 cap-and-trade program in Virginia: to "grow the clean energy economy" and "make clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio." ED-11 notes an increase in "the number of solar jobs in Virginia" and the increase in "revenue for energy efficiency businesses in Virginia." While these are laudable goals, it is a misuse of governmental authority to use environmental regulation for non-environmental purposes. There are other, more appropriate authorities and programs to accomplish these economic goals. It appears that the environmental benefit envisioned from the regulation of CO_2 emissions is the mitigation of the risks to Virginians from climate change. The administrative record is devoid of scientific data or other information to support the conclusion that the proposal would have any perceptible effect on the severity of storms or flooding in Virginia. The preamble to the proposed regulation contains a chart of "Health Benefits of Incidental Reductions in SO_2 and NO_X." The rationale is that regulating emissions of CO_2 would have the "incidental" benefit of reducing emissions of SO_2 and NO_X. However, there are numerous other air regulatory authorities and programs addressing emissions of SO_2 and NO_X, including their own cap-and-trade programs. Thus, if additional regulation of SO_2 or NO_X is deemed necessary, there are other, more appropriate regulatory programs to directly address this necessity. Virginia does not have to resort to CO_2 regulation to indirectly address concerns with SO_2 or NO_X emissions. More specifically, the board cannot say the proposed regulation is needed to address emissions of SO_2 or NO_X . Incidental reductions in SO_2 and NO_X provide no rationale for imposing the proposed CO_2 emissions cap-and-trade program in Virginia. DPB's Economic Impact Analysis states: ". . . EPA and other federal agencies use estimates of the social cost of carbon (SC-CO_2) to value the climate impacts of regulatory rulemakings. The SC-CO_2 is a measure, in dollars, of the long-term damage done by a ton of CO_2 emissions in a given year. This dollar figure also represents the value of damages avoided for a reduction of a ton of CO_2 emissions in a given year (i.e. the benefit of a CO_2 reduction). It should be noted that the federal model estimates of the social cost of carbon are for the world overall. Thus it is not possible to quantify the Virginia-specific benefits." There is a reason why the value of damages avoided in Virginia is impossible to quantify. The effect, if any, of reducing CO_2 emissions from Virginia's electric power sector on the severity of	sets an overall cap but otherwise does not dictate which sources must make reductions. Through emissions trading, the program delivers the lowest cost reductions possible. Virginia has years of experience and considerable success with this kind of program. In addition to the inherent flexibility provided by emissions trading, the program also provides for the allocation of allowances to the entities with a compliance obligation. Allowances have value, and that value will be realized in the consignment auction, with revenue returning to compliance entities. The revenue returned to compliance entities from the compliance auction will serve to offset and mitigate the costs of the program for compliance entities and consumers. The analysis in the record is clear on these points. While the program minimizes costs through emissions trading and mitigates costs through allowance value, it also produces real benefits for Virginians. The administrative record demonstrating the impacts of climate change and the benefits of encouraging clean energy in Virginia toward the protection and improvement of Virginia's environment is well-documented. The focus of the EO 57 Work Group was to evaluate options under the Governor's existing authority while

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	storms or flooding in Virginia would be negligible at best. The regulation would provide no measurable environmental benefit to Virginia. Climate change and reduction of GHG emissions are global issues. Climate change is not a local phenomenon and to the extent man can craft a solution to climate change by reducing CO_2 emissions, that solution cannot be accomplished by disjointed state and local approaches. If any regulation of CO_2 in the U.S. is deemed necessary to address climate change, that regulation must be undertaken and applied uniformly throughout the country, not state by state or locality by locality. The costs of the regulation outweigh any purported benefits. In its Economic Impact Analysis, DPB notes that the proposal likely would increase electricity costs for Virginia's citizens and businesses by no more than 1.1% ($2015) by 2031. However, a recent study by the Cato Institute showed that electricity costs in the RGGI states rose by 4.6% between 2007 (pre-RGGI) and 2015. This increase was 64% higher than the increase in electricity costs in a sampling of 5 non-RGGI states. As the data from the RGGI states show, adoption of the proposed CO_2 emissions cap-and-trade program will add millions of dollars per year to the electric bills of the citizens and business of Virginia. Virginia has a robust manufacturing sector and is ranked as the fourth most competitive state in overall manufacturing competitiveness in the nation. Moreover, Virginia is ranked the most competitive southern state for manufacturing. However, this position would be jeopardized by increasing energy costs. The Cato Institute study found that from 2007-14 the economies of the 5 non-RGGI comparison states grew 2.5 times faster than the RGGI states. During the same period the RGGI states lost 35% of energy intensive businesses, whereas the 5 non-RGGI comparison states only lost 4%. While the non-RGGI comparison states' overall goods production grew by over 15%, the RGGI states lost 13% of overall goods production. This decline is reflected in industrial electricity demand with the RGGI states falling 17% while non-RGGI comparison states only fell 3%. The greater decline in energy demand in the RGGI states cannot be attributed to greater energy efficiency in those states. In fact, the RGGI states improved by 9.6%, while the non-RGGI comparison states improved by 11.5%. Even as the economy was recovering from the 2008 recession, industry was leaving the RGGI states. If the program is enacted in Virginia, electricity costs for manufacturing facilities will undoubtedly increase, by as much as 4-5% by 2031. This increased cost of operation will diminish Virginia's competitive advantage. If Virginia participates in RGGI, we can expect the same fate for our industry that the RGGI states have experienced--	simultaneously creating more clean energy jobs. (The legal authority to develop this program in the first place is well established; see the response to comment 76 for more detail.) The process consisted of monthly meetings with presentations from the public. Numerous presenters described the impacts of climate change to the Working Group, and presenters included Dominion Energy, the American Petroleum Institute, Covanta, WestRock, and other stakeholders involved in manufacturing and energy generation. The Work Group also received over 8,000 written comments during a 3-month public comment period. The basis for EO 11 and this regulatory development action are, therefore well-established. Note that other commenters describing detailed environmental and fiscal impacts to the state were also submitted during this proposed regulatory development stage; they are summarized here and the full comments are part of the public record (see, for example, comments 108, 121 and 139). DPB's analysis was based on the best available information, including an analysis of potential changes in residential, commercial, and industrial customer electricity bills prepared for the department by the Analysis Group, an internationally recognized economic consulting firm. In addition,

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	industry will go where costs of energy are lower.	the Virginia Joint Legislative Audit and Review Commission (JLARC) in its Fiscal Impact Review of ED 11 (December 2017) found that the fiscal impact of the proposed regulation on state government should be minimal. The impact is estimated to be negative in 2020 when the regulation takes effect and be approximately $1.9 million (in 2017 dollars) in 2031, the last year for which information is available for developing an estimate. Nearly all of the impact is because of the impact to electricity costs for state agencies and public higher education institutions. Based on the results of these studies as well as various modeling exercises, DEQ maintains that impacts on electricity consumers will be minimal. In fact, the latest analysis of customer bills based on updated modeling shows that average bills will slightly decrease as a result of the rule. Non-carbon benefit information provided in the public notice comes from DPB's analysis and quotes EPA COBRA analysis. The latest COBRA analysis again shows significant economic co-benefits resulting from criteria pollutant reductions as a result of this rule. The primary purpose of the regulation is to control CO_2; however, it is accurate to note that there will indeed be other air quality benefits associated with the control of carbon pollution. This discussion is part of the

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		comprehensive economic analysis required by state law that attempts to identify significant impacts--direct and indirect--of the regulation. No analysis of the costs and benefits of the proposal can accurately say that there will be no impacts on other pollutants. DEQ agrees that climate change is a global problem. However, in the absence of a federal program, the Commonwealth is well within its authority to address air pollution within its borders. Linking to RGGI is not a "go it alone" approach; it will enable Virginia to leverage its pollution reduction efforts with a well-established, proven effective interstate program. As discussed in RGGI's most recent market analysis, carbon intensity is decoupling from energy generation in the RGGI region. In addition to its own analyses DEQ has reviewed the results of the RGGI program and finds that costs have been contained and benefits have been realized. See, for example, the most recent recent report prepared by the Analysis Group, "The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States: Review of RGGI's Third Three-Year Compliance Period (2015-2017)." This analysis found that RGGI continues to to lower CO_2 emissions while benefiting local and regional economies and employment opportunities.

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		The report estimates that RGGI states will realize $1.4 billion in net economic value from RGGI's implementation during the 2015-2017 period. According to the report, the program also will create more than 14,500 new job-years (the equivalent of one full-time job for the duration of one year) due to the program's implementation during the past three years. In addition, CO_2 emissions from power plants have dropped by more than 50% over the 9 years since RGGI began. DEQ realizes that the electric generation system in RGGI is different, and that Virginia's participation in RGGI will be via consignment rather than direct auction; however, all indications are that linking to RGGI will be beneficial for Virginia. The energy price projections resulting from the updated modeling are lower than the previous modeling exercise in 2017. Thus, the cost of the program will be less for consumers and regulated sources than previously estimated. Ignoring the costs of carbon pollution will endanger Virginia's competitive advantage, and linking to RGGI is a step toward addressing that risk. DEQ is well aware of the need to address air pollution in the fairest, most cost-effective means possible, which is why the program is flexible and allows emissions trading to seek out the lowest cost

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		reductions possible. DEQ has also taken measures to ensure that the program goals are realistic and can be reasonably achieved; see, for example, the response to comment 37. In short, the program has been designed to minimize impacts on businesses and consumers while achieving DEQ's air pollution control mission to protect public health and welfare.
62. AdvanSix, Greif, ODEC, Virginia Manufacturers Association (VMA)	The regulation imposes a carbon tax and cedes this tax authority to RGGI. The regulation envisions a process whereby conditional allowances are allocated by DEQ to regulated sources. Those regulated sources are compelled to consign the conditional allowances to RGGI for auction. Regulated sources throughout Virginia and the RGGI states can bid on the allowances. RGGI states have taken the auction revenue and used it for a variety of purposes, one of which is not related at all to the goal of reducing CO_2 emissions: 8% of the revenue was used "for state budget reduction," just like any other tax revenue that goes into the state's coffers. The cap-and-trade program in Virginia is supposed to operate differently. Revenue generated by the auction of conditional allowances consigned by a regulated Virginia source is supposed to be returned to that source owner, less RGGI administrative fees. DEQ has indicated the revenue received by owners of regulated electric utilities will "flow to rate payers pursuant to SCC requirements." However, we have no idea that will actually happen or to what purposes the revenue would be put. The provisions governing the allocation and auction of CO_2 emission allowances, whether conducted by DEQ under the board's authority or RGGI, are designed to produce revenue to fund energy efficiency programs, resiliency infrastructure, and other government purposes. The overlay of the additional cost imposed by the auction of CO_2 emission allowances constitutes a tax. The magnitude of that tax will not be set by Virginia; it will be set by RGGI, a non-governmental entity. The General Assembly may delegate the power of taxation to any county, city, town, or regional government (Va. Const. art. VII, § 2). However, the General Assembly cannot delegate its taxing power to an unelected entity, whether the board, DEQ or RGGI. The Constitution and case law are quite clear on these matters. Although the Constitution does not explicitly prohibit the delegation of such decisional authority concerning the imposition of taxes, that delegation is prohibited by necessary implication, and the General	The definition of "tax" is well established in state and federal law. The purpose of the regulation is to control and abate carbon air pollution, not to generate revenue. Rather than impose a tax, the regulation requires the issuance of allowances by the department to CO_2 budget units. An allowance is a limited authorization by the department under the trading program for CO_2 budget units to emit up to one ton of CO_2. Allowances are then traded within the confines of a consignment auction. No money is generated for or sent to the state.

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	Assembly may not delegate its taxing power to a non-elected body. Thus, the Virginia Constitution prohibits ceding tax power to the board, DEQ or RGGI.	
63. AdvanSix, Greif, ODEC, Virginia Manufacturers Association (VMA)	The program is unnecessary. Virginia's per capita energy use fell from a peak of 346 MBtu per person in 2005 to 292 MBtu in 2013 and 2014. Virginia's 2014 rate is lower than the national average of 309 MBtu and ranked Virginia 21st among U.S. states for energy consumption. The decrease in energy consumption translates into a decrease in CO_2. From 2000-15, Virginia's energy-related CO_2 fell by 16.3%; the RGGI states averaged a 17.1% decrease and the entire U.S. experienced a 10.3% drop. Virginia already generates a relatively low amount of GHGs from electrical power generation, transportation, heating/cooling, and industrial processes. Virginia's CO_2 emissions decreased from 15.9 tons per person in 2005 to 12.5 tons in 2014. This was substantially better than the national average of 17.0 tons per capita and ranked 13th best in the country. Virginia is reducing its carbon footprint at a rate better than the nation and comparable to the RGGI states even without a cap-and-trade program. Virginia's electric utilities are expanding the role of renewable energy in power generation. Dominion has solar facilities capable of producing approximately 744 MW of power either operational or under development. ODEC has approximately 300 MW of renewable energy generation capacity, and plans to add 70 MW of solar generation in the next 5 years. As technology costs decrease, solar electric generation is growing rapidly in Virginia. According to the Solar Energy Industries Association, Virginia's total solar capacity of 619.5 MW at the end of 2017 ranked 17th among the states. SEIA data indicate that Virginia's solar generation fleet grew by 381.3 MW in 2017. Virginia ranked 10th in the nation last year in adding solar capacity. Dominion's 2017 IRP calls for the addition of at least 3,200 MW additional solar capacity by 2032 and at least 5,280 MW additional solar capacity by the end of a 25-year study period concluding in 2042. Dominion is moving forward with a project consisting of two, 6-MW turbines that will become the mid-Atlantic's first offshore wind project in a federal lease area. Larger-scale deployment of turbines in an adjacent site could potentially produce up to 2,000 MW of electricity. SB966 (2018), states that construction or purchase by Virginia electric utilities of solar and wind-powered facilities capable of producing up to 5,000 MW of electricity at maximum output is "in the public interest." It is clear that Virginia's electric utilities are moving rapidly to greatly expand generation from renewable resources. Virginia is already among the nation's leading states in this regard. A costly CO_2 program is unnecessary to	The program is needed. DEQ's modeling analysis suggests that carbon emissions from the electricity sector will increase without the program. The analysis is consistent with similar analyses conducted by the federal Energy Information Agency (EIA) showing emissions generally flat or modestly increasing in the coming years and decades. While emissions have decreased in some recent years, that trend is reversing and emissions are expected to continue to increase without the trading program. The commenter is correct that renewable energy development is expanding in Virginia, and it is expected that this trend will continue. DEQ has also recognized the value of these types of programs by establishing the 5% set-aside. New renewables and energy efficiency will make compliance with the trading program easier, but neither new renewables nor energy efficiency guarantee an emissions reduction from the sector. The program does.

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	promote the continued rapid growth of renewable energy generation in the state.	
64. AdvanSix, Greif, ODEC, Virginia Manufacturers Association (VMA)	Virginia's electric utilities have billions of dollars invested in assets that serve the public good and generate returns for investors. If the program fails to allocate allowances necessary for those facilities to generate electricity, that failure would deprive those entities of their ability to operate. In essence the government would be taking the value of those electric generating assets from Virginia's utilities without public need and compensation. Similarly, if sufficient allowances for Virginia's utilities to operate are allocated but then forced to be consigned to RGGI for potential purchase by someone else, the board would be taking valuable allowances away from these companies without public need and compensation. Such "takings" are prohibited by the U.S. and Virginia Constitutions. Virginia is a member of numerous interstate and regional compacts. An essential feature of these compacts is authorization by the U.S. Congress and confirmation by the General Assembly. Linking to RGGI by compelling the consignment of allowances to RGGI for general auction would constitute an unauthorized compact with the RGGI states. Attempting to do so would exceed the authority of the board. Emission allowances should be allocated without cost to EGUs that will be constrained by the emissions cap. Direct auction of the allowances with the revenue collected by the state would constitute a tax. A direct auction would greatly increase the cost of the program to Virginia citizens and businesses.	DEQ disagrees with the commenter's assertion that the allocation of allowances constitutes a taking of value. As described in 9VAC5-140-6050 C 9, a CO_2 allowance does not constitute a property right. The allocation of allowances in no way deprives electricity generators of their ability to operate. That would defeat the purpose of the emissions trading program. Allowances are allocated based on actual generation (versus static historical generation), thus providing facilities with greater flexibility. Linking to RGGI does not constitute entering a compact. RGGI is a cooperative venture, governed by consensus among member states to maximize collective emissions reductions capabilities. Linking to RGGI does not exceed any federal or state requirement, nor does it directly impose any legal requirements on Virginia or its regulated community. As discussed in the response to comment 76, the board has the legal authority to control carbon pollution. Linking to RGGI is the most cost effective and efficient means of accomplishing this goal.
65. AdvanSix, Greif Packaging, Virginia Manufacturers Association (VMA)	Fossil fuel-fired units that serve electrical generators smaller than 25 MWe and industrial facilities should not be included in the proposed program. ED 11 speaks in terms of "electric power facilities," and EO 57 speaks in terms of "power plants," "the electric sector," "electric companies," and "electric utilities." It is clear that the mandate from then-Governor McAuliffe was for the board to propose a CO_2 cap-and-trade program tied to RGGI	DEQ agrees with the commenter's characterization of the directive to control carbon emissions from fossil fuel-fired generators. The ED 57 Work Group specifically recommended that the

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	that would apply to facilities whose primary, if not exclusive, purpose is the generation of electricity for sale to the public. Industrial facilities are not power plants owned by electric companies and operating in the electric sector, and are clearly outside the scope of EO 57 and ED 11. Many industrial facilities in Virginia do not have multiple locations with different energy generating capacities to provide flexibility in meeting a CO_2 emissions cap. They have one facility and cannot shift allocations between facilities and generating technologies. Virginia's electric utilities have multiple units and generating technologies which allow them to find the least expensive way to reduce CO_2 emissions. Utility power producers are in the business of building alternative power generation sources while manufacturers are not. It is easier for utility power producers to shift the mix of generation to renewable power. Electric utilities have economies of scale and may purchase larger and a greater number of alternative generation units. Manufacturers' power needs are generally much smaller. Electric utilities are better able to pass their costs on to their customers, while manufacturers do not have a captive customer base. They compete worldwide for business from customers who are acutely price sensitive. Large capital expenditures for alternative energy generation would increase the price of products and damage their market position. Electric utility revenues are not affected by these global market demands. Emissions from industrial sources comprise only 11.3% of Virginia's CO_2 emissions. Expanding cap-and-trade to the manufacturing sector would impose significant costs with only a small reduction in emissions. The regulation does not define "primary use." The dictionary sense of "primary" would allow a facility to export just under 50% of the electricity and heat generated from fossil fuels on site and still qualify for the exemption. The reality is that no manufacturing facility comes close to exporting 50% of the energy generated on site. However, the regulation should provide manufacturing facilities a margin of flexibility to export energy when it is not all needed on site. "Primary use" should mean that in order to qualify for the exemption, no more than one third of the power generated on site, in the form of electricity and heat, can be exported. This approach is based on the cogeneration exclusion in Virginia's CAIR rule. For example, 9VAC5-140-1040 B 1 a (2) excluded cogeneration units provided they did not supply more than one third of the unit's potential electrical output capacity to any utility power distribution system for sale.	Governor consider taking action via a regulatory process to establish a trading-ready carbon emissions reduction program for fossil fuel-fired electric generating facilities. In the RGGI Model Rule, facilities that provide less than 10% of their power output to the grid are exempted from compliance obligations. DEQ also evaluated dedicated electricity generating units serving industrial facilities in Virginia, and determined that those facilities would not qualify as CO_2 budget sources. These facilities are already subject to a stringent permitting process to control criteria and toxic pollutants, and are closely monitored in order to ensure that they are meeting state requirements for controlling those emissions. Exemption of this level of industrial producers is also consistent with the RGGI model rule. The proposal has been amended to remove the phrase "owned by an individual facility." This change is being made in order to ensure that facilities are not penalized for employing more energy efficient and less polluting generating systems that may be operated by a third party on behalf of the primary facility. The proposal has also been modified to set a threshold for what constitutes "primary use of operation of the facility." These changes are necessary in order that the applicability provisions be consistent with RGGI's

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		2017 Model Rule. Note that ongoing program reviews will provide the opportunity to adjust the exemption if necessary. There may also be opportunities in separate future rulemakings to directly address the exemption should implementation issues be identified.
66. Virginia Advanced Energy Economy (AEE)	AEE supports a CO_2 budget trading program. The regulation will help to make Virginia's energy more secure, clean, and affordable, bolstering the state's economy while reducing emissions. We support the ability of the regulation to integrate into other carbon markets. Integration with other states and regions will help Virginia achieve greater efficiencies and further reduce emissions. Utilizing the State Tool for Electricity Emission Reductions (STEER), AEE analyzed possible compliance pathways. With a diverse portfolio of advanced energy resources, including renewables and energy efficiency, the state could reduce emissions by over 13.3 million tons between 2020-30 at little to no cost, far surpassing the proposed targets. We recommend a 2020 baseline at or below 33 million tons. Lowering the baseline may encourage system planners and grid operators to accelerate the deployment of advanced energy resources in preparation for the 2030 targets. Such accelerated deployment is beneficial to ratepayers, as it would take advantage of the federal production tax credit for wind and the investment tax credit for solar and other advanced energy technologies. These incentives lower the costs of renewable resources, savings that will be passed along to consumers. Given the cost-effectiveness of energy efficiency, the sooner it is deployed the greater the cumulative savings will be to ratepayers. Our modeling also indicates that with a portfolio of advanced energy technologies in conjunction with coal-to-gas switching, Virginia can beat its 2030 carbon reduction target by approximately 3.4 million tons. These results suggest that actual reductions will exceed targets. When emissions reductions outstrip targets it has the effect of lowering the price of a carbon credit. While keeping the price of credits in check is preferable, significantly depreciating them is not, as it depresses the market and introduces volatility. We support the CCR and the ECR as they ensure that	Support for the proposal is appreciated. DEQ recognizes the value of the renewable energy market and energy efficiency measures as important tools in reducing carbon pollution. The program will promote both renewables and energy efficiency by putting a price on carbon emissions. The program effectively encourages renewables and efficiency because they are carbon-free resources and do not have a compliance obligation, unlike carbon-emitting resources. DEQ also recognizes that CHP units are highly efficient, and do not encourage the development of fossil fuel-fired generation. The program achieves its primary environmental objective through the cap, and not the allocation method. Note, however, that the updating output-based allocation methodology will reward units that produce more electricity with lower carbon emissions. In the past, DEQ has always allocated allowances to compliance entities and not to other entities, with the exception of set-asides to promote energy efficiency. This

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	carbon prices remain within a predictable range. However, we prefer predictable and robust prices established and maintained through the market, as opposed to out-of-market interventions. Such prices are essential to the effective financing of advanced energy projects. We recommend that the rate at which the cap decreases each year be 4% annually, and that the ECR and CCR be adjusted correspondingly. These changes will help ensure that targeted and achieved reductions move in closer alignment, and that market functions proceed smoothly. Under the proposal, all permits are allocated to generators (less the set-aside) based on a 3-year average of net generation. We approve of basing allocations on generation, as opposed to historic emissions, as well updating allocations over time. To encourage compliance, we recommend that the rule allocate allowances to all generating units equal to or greater than 25 MW regardless of technology. This will ensure that the allowance allocation remains technology neutral and encourage competition among emission reduction measures. CHP units that generate heat and power for an individual facility are exempt. Given the efficiency of such systems, and the corresponding emissions benefits, this exemption is reasonable. We recommend that "owned by an individual facility" be removed. This will ensure that CHP systems that serve an individual facility are exempt regardless of ownership status. In order to ensure that the "primary use" of the CHP system is indeed to serve the individual facility, the regulation should specify that a minimum of 85% of the useful energy output be used at the site. As proposed, a covered CHP system must account for emissions created in the production of electricity and useful thermal energy (UTE). However, absent a CHP system, such thermal energy would be generated through a conventional method that is not subject to the regulation, potentially discouraging the use of CHP while creating new emissions from non-covered sources. The UTE exemptions put forward by other states should be considered. AEE supports the 5% set aside for DMME. According to studies by EPRI, by 2030 energy efficiency programs have the potential to save Virginians over 23,000 GWh of generation, more than 17% of the state's load, each year. On Virginia's current trajectory, the state will achieve just 5% of that potential. This underperformance stems from underinvestment in energy efficiency and a misalignment of incentives. Until this misalignment is reformed we support allowing experienced parties the ability to implement programs in addition to the utilities. We recommend doubling the set-aside to 10% in order to	program takes a similar approach. The structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement that set-aside. DEQ believes the set-aside should be 5% in the early stages of the program, and this percentage is consistent with past DEQ programs. The set-aside may be revised at a later date as the state gains experience with the program and with the program DMME develops. DEQ agrees that the phrase "owned by an individual facility" should be removed. Under the RGGI Model Rule, facilities that provide less than 10% of their power output to the grid are exempt from compliance obligations; the proposal has been revised accordingly.

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	provide a more robust financing stream. According to our modeling, energy efficiency has the potential to help Virginia meet its carbon mitigation targets while reducing rates, creating jobs, and stimulating new in-state investment. The challenge energy efficiency presents lies in the ability of system planners, regulators, and other stakeholders to effectively track, evaluate, measure, and verify the energy savings produced by an array of energy efficiency programs and measures. The National Energy Efficiency Registry (NEER) helps states track and verify energy efficiency savings and transform those savings into tradable instruments parties may then use for compliance. Regulators and stakeholders should use NEER to facilitate the administration and tracking of energy efficiency programs in Virginia. Employing consistent and well-established methods for evaluation, monitoring, and verification of savings will help Virginia effectively tap into this cost-effective resource. Voluntary purchasers of renewable energy do so in part based on carbon reduction benefits. In many states, the purchase of a REC includes the purchase of environmental attributes associated with the carbon reductions of that power. Unless the voluntary market is taken into account, a statewide carbon reduction requirement could undermine voluntary purchaser commitments because they will no longer represent a regulatory surplus. Several programs have avoided this through a voluntary purchaser set-aside. This can also be done by allocating allowances to resources that reduce emissions rather than only to emitting resources. This will allow advanced energy resources to fulfill any contracted-for obligations to transfer allowances to purchasers under existing power purchase agreements. Those purchasers can then choose to do what they wish with the allowances. This gives purchasers the choice to retain these allowances if they wish to preserve the project's regulatory surplus.	
67. American Forest and Paper Association; American Wood Council; Forest Products Industry National Labor Management Committee; Virginia	The following principle should be incorporated into the regulation: "Emissions from the combustion of any forest-derived biomass shall not be considered a GHG if: 1) timberland carbon stocks, based on U.S. Forest Service Forest Inventory and Analysis data for the U.S. South Region, are stable or increasing relative to the 2005 carbon stocks assessment for this region; or 2) the forest-derived biomass is from forest products manufacturing residuals, harvest residues, or waste-derived feedstocks, including used wood products." Subsection 1 is based on the fact that harvesting wood for energy does not contribute to net carbon emissions in cases where it is offset by wood growth and associated carbon sequestration. U.S. Forest Service data shows	DEQ is well aware of the concerns associated with biomass, and discussed the pros and cons of including or excluding biomass units with the Regulatory Advisory Panel established to advise and assist in the development of the regulation. The group did not reach consensus on an approach for dealing with biomass; given that, and given the numerous, detailed comments

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Agribusiness Council; WestRock	carbon stocks in trees on timberland across the southern U.S. have increased from 4.9 billion tons in 2005 to 5.6 billion tons in 2016. This shows biogenic CO_2 from biomass removed from the forest is more than offset by removals of CO_2 from the atmosphere by growing forests. Also, 2016 data from the U.S. Forest Service demonstrates that the growth/removal ratios for timberlands in Virginia is 2.29, meaning timberlands are growing more than twice as much wood as is being harvested. This positive net growth/removal ratio shows that Virginia forestry is more than sustainable. Finally, strong markets for wood preserve forests by providing an incentive not to convert the land to other uses. Subsection 2 is based on the fact that emissions from forest products manufacturing residuals, harvest residues, or waste-derived feedstocks would eventually enter the atmosphere even if they are not used for energy production. Simply landfilling these feedstocks can result in methane emissions, which have a much greater impact on global warming than CO_2. The use of biomass residuals each year avoids the emission of approximately 181 million tons of CO_2 indicating there are GHG reduction benefits in using forest products residuals for energy in the pulp, paper, packaging and wood products industry.	received during the public comment period, DEQ recognizes that this is a polarizing subject. However, the ED 57 Work Group specifically recommended that the Governor consider taking action via a regulatory process to establish a trading-ready carbon emissions reduction program for fossil fuel-fired electric generating facilities. The RGGI Model Rule provides that a biomass-fired facility may be a CO_2 budget source if the use of fossil fuel combusted comprises, or is projected to comprise, more than 50% (commence operation pre-2005) or 5% (commence operation post-2005) of the annual heat input on a Btu basis during any year. DEQ evaluated the fuel mix of the 5 potentially affected biomass-fired facilities in Virginia, and determined that those facilities would not qualify as CO_2 budget sources. These biomass-fired facilities are already subject to a stringent permitting process to control criteria and toxic pollutants, and are closely monitored in order to ensure that they are meeting state requirements for controlling those emissions. Additionally, most RGGI states allow CO_2 budget units that co-fire eligible biomass to deduct CO_2 emissions attributable to the burning of eligible biomass from their compliance obligation in accordance with the RGGI

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		model rule. DEQ has amended the proposal to indicate that a CO_2 allowance is a limited authorization to emit up to one ton of CO_2 that has been generated as a result of combusting fossil fuel. Finally, periodic program reviews at the RGGI and state level will provide opportunities to adjust the exemption should implementation issues be identified. The proposed definition of "fossil fuel-fired" is inconsistent with the RGGI 2017 Model Rule, which sets a threshold of 5% of the annual heat input on a Btu basis during any year, and the regulation has been amended accordingly. This change is necessary in order to ensure that Virginia's regulation is a corresponding CO_2 Budget Trading Program regulation, such that Virginia can be considered a RGGI Participating State; the proposal has been amended accordingly.
68. American Forest and Paper Association; American Wood Council (AF&PA and AWC)	AF&PA and AWC do not support Virginia joining RGGI because it will raise electric power prices and consequently cause Virginia-based businesses to become less competitive. Biogenic CO_2 emissions from forest-derived bioenergy should be counted as making zero contribution to the build-up of GHGs in the atmosphere where timberland carbon stocks are stable or increasing. Through the natural carbon cycle, growing forests sequester carbon as trees are replanted and grow through their lifecycles, even as some trees are harvested. Recent data from the U.S. Forest Service indicate that timberlands in Virginia, the U.S. south, and the entire U.S. have positive net growth/removal ratios. Virginia's timberlands are growing more than twice as much wood as is harvested. The most significant pressure on forests is conversion to non-forest uses, such as development. By contrast, strong markets for wood help to preserve forests by providing	The commenters' concerns are recognized. As discussed in greater detail in the response to comment 61, potential costs and benefits have been rigorously examined, and the program has been designed to provide the maximum benefit at the least possible cost. See the response to comment 67 for further discussion of how biomass will be treated under the program and the response to comment 65 for further discussion of industrial boilers.

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	an incentive to not to convert land to other uses and to invest in healthy forest management practices. A Journal of Forestry article concluded that "[t]he demand for wood keeps land in forest, provides incentives for expanding forests and improving forest productivity, and supports investments in sustainable forest management that can help offset the forest carbon impacts of increased demand." A U.S. Department of State report shows that strong demand for forest products will increase forest carbon stocks through ongoing landowner investment. Paper and wood products mills rely on residuals from the manufacturing process for steam and power for their operations or to sell electricity to the grid, and there is consensus that the use of residuals and biowastes for energy has significant GHG reduction benefits. A study published in the Journal of Industrial Ecology concluded that "[T]he use of biomass residues from forest products manufacturing, including black liquor, to produce energy in the U.S. forest products industry for 1 year avoids, over a 100-year period, 181 million tons of CO_2-equivalent emissions per year. Even ignoring the displacement of fossil fuels such as coal, the article finds that the avoided disposal of forest products manufacturing residues alone produces a GHG reduction benefit of approximately 5 million t CO_2-eq/yr." This is equivalent to removing one million cars from the road. The article states that ". . . if mill residues were not used for energy, most of these materials would be wastes that would be either incinerated, in which case the atmosphere would see the same biogenic CO_2 emissions as if the material had been burned for energy, or disposed in landfills." Disposal of residues in landfills creates methane, which has about 28 times greater global warming potential than CO_2. The article concludes, "consider[ing] all GHGs and fossil fuel substitution, the overall [GHG reduction] benefits of using manufacturing residuals for energy are large and become evident in short periods." Forest biomass, including manufacturing residuals, should be treated as carbon neutral whether or not it is co-fired with fossil fuel. The carbon profile of biomass is not altered simply because it is co-fired. This distinction is not scientifically supportable given that the biomass portion of the fuel mix has the same characteristics regardless of whether it is co-fired with 9% fossil fuel, 10% fossil fuel, or 90% fossil fuel. It is the biomass portion of the fuel mix alone that should be evaluated for net carbon emissions. The regulation should not cover industrial boilers. ED 11 pertains exclusively to controlling CO_2 emissions from "electric power facilities." Likewise, EO 57 directed the Work Group to recommend methods to reduce CO_2	

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	emissions from "electric power generation facilities." The Economic Impact Assessment, the charge given to the Regulatory Advisory Panel, the emissions and economic modeling conducted by DEQ and its consultants, and DEQ's information leading up to and supporting the proposal indicated that the regulation applied only to the electric power sector. Indeed, covering only utilities is consistent with the intent and scope of the existing RGGI program, and RGGI allowance prices are based on the marginal cost to reduce GHG emissions from the utility sector and do not reflect the capability of industrial sources to reduce emissions. Unlike the electric power sector, industrial facilities must compete in a highly competitive global marketplace and do not have the comparable ability to pass on increased compliance costs to customers. Accordingly, it would be arbitrary and capricious, a violation of due process, and fundamentally unfair for the final rule to include other emission sources, such as industrial boilers. We also urge that the state retain the issuance of free allowances rather than conduct auctions, which would drive up compliance costs and harm the households and businesses served by the power grid.	
69. Appalachian Power/American Electric Power (APCo/AEP)	It would not be in the best interest of the state to develop incremental carbon policies to intervene in an ongoing transformation of the electric sector. Given that the Virginia regulatory process is robust and that CO_2 emissions have trended significantly downward, additional restrictions on carbon emissions could put Virginia at a competitive disadvantage. Unlike the Clean Power Plan, which included all states, a Virginia-specific carbon strategy would distort economic decisions. Carbon restrictions that are more stringent than national standards could lead to existing generating facilities being closed or new facilities constructed elsewhere, leading to a loss of both employment opportunities and tax revenue. The regulation will also result in higher customer rates, which would place additional stress on the finances of households and business, and influence where businesses choose to locate. DEQ has not provided adequate analysis supporting that benefits of the regulation for Virginia citizens would outweigh the costs. APCo is encouraged by the fact that DEQ has proposed a cap and trade program as the regulatory structure. Cap and trade programs have long been documented as effectuating emission reductions at the lowest cost. APCo supports allowance banking and a CCR allowance should allowances costs exceed projections. This is a fair way to ensure that consumers and businesses are not unduly burdened. APCo does recommend that several aspects of the regulation be modified. First, DEQ has not provided an adequate rationale for use of a	Support for the proposal is appreciated. As discussed in the response to comment 61, Virginia's carbon control strategy is not go-it-alone; the purpose of the regulation is to leverage Virginia's carbon reduction efforts by linking to a well-established and effective multi-state program. DEQ agrees that cap-and-trade programs are effective in controlling emissions. However, as discussed in the response to comment 64, DEQ has designed the program to implement a consignment auction rather than a direct auction. This will ensure that Virginia can link to RGGI while accommodating Virginia's unique utility regulatory regimen, and ensure a stable, transparent and fair program. See comments 108 and 136 for further discussion of the appropriateness of the

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	consignment auction. Cap and trade programs have been overwhelmingly successful with a direct allocation to affected sources. Second, the allocation mechanism for allowances on the basis of updating net generation output does not acknowledge the inherent differences in carbon emissions between units utilizing different fossil fuels. Units using fuels with a higher carbon content are unfairly disadvantaged by the allocation process, even as they are subject to a declining carbon cap. APCo recommends directly allocating allowances to affected generators on the basis of actual emissions.	consignment auction.
70. Appalachian Power/American Electric Power (APCo/AEP)	APCo does not support allocation of conditional allowances to DMME. There is no adequate rationale for this set-aside. Under a cap and trade program affected sources and other parties have the incentive to utilize the most cost effective way to comply with the program and/or associated costs. The proposed set-aside effectively represents a 5% tax on affected sources and ultimately consumers and there is no justification that the benefits of this "tax" will justify any benefits that may be provided.	The primary purpose of EO 11 is to control carbon emissions from fossil fuel-fired power plants; however, EO 11 has also identified the encouragement of clean energy as a program goal. A 5% set-aide is modest, and will enable the state to determine the effectiveness of this type of program; see the response to comment 51 for further detail. To characterize the set-aside as a tax is inaccurate as discussed in the response to comment 62.
71. Appalachian Power/American Electric Power (APCo/AEP)	Inclusion of new units will be a disincentive to siting new fossil generation within Virginia as these units would be subject to an incremental cost associated with complying with the regulatory program. As such, units could be more cost effectively built in adjoining states not covered by the Virginia program, thus depriving the state of jobs and tax revenue associated with new generation facilities.	Inclusion of new sources is consistent with the RGGI program. In order for carbon reduction efforts in Virginia to succeed over the long term, new fossil fuel sources in the state must be considered. DEQ is confident that leakage will be addressed by a variety of RGGI and Virginia mechanisms; see comments 91, 108, 136 and 144 for more detail.
72. Appalachian Power/American Electric Power (APCo/AEP)	APCo has concerns with the need to maintain a new Virginia-specific database for GHG emission reporting, operating and maintaining a new database and software program for allowance trading, and maintaining records associated with CO_2 emissions and accompanying reports. APCo already maintains systems for emissions reporting and record retention per federal requirements, which differ significantly from those Virginia has proposed. Better aligning the proposed reporting, trading and compliance programs with the federal systems already in place would reduce the administrative burden	Because Virginia is linking to an existing trading program, it is not anticipated that any new Virginia-specific database will be needed. The Commonwealth is expected to use the RGGI COATS system to track allowances and emissions. The COATS system accepts

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	of the rule.	emissions reporting consistent with federal requirements and is connected to EPA's emissions reporting system.
73. Appalachian Power/American Electric Power (APCo/AEP)	The higher starting cap of 34 million tons of CO_2 would mitigate the economic impact of the regulation. The higher cap would have imperceptible impact on the environmental effectiveness of the program with the benefit of lower resulting compliance costs.	The starting cap will be 28 million tons; see the response to comment 37 for more information.
74. Alliance for Industrial Efficiency	We commend DEQ for developing this regulation. Our members support market-based programs like RGGI because they account for the cost of carbon emissions while promoting economic growth. The regulation provides Virginia the opportunity to capture the economic benefits of transitioning to a low carbon economy. We applaud DEQ for recognizing the most economically efficient means for reducing CO_2 emissions in Virginia: incentives for energy efficiency. Finally, we commend DEQ for exempting certain industrial CHP units, which recognizes the emissions benefits offered by these systems. CHP systems produce heat and electricity from a single fuel source. Instead of generating power and letting the waste heat escape, CHP systems harness the thermal energy for heating, cooling, and other applications. Waste heat to power systems capture waste heat from industrial processes to make electricity, requiring no additional fuel and generating no further emissions. Not only does CHP have higher efficiencies than conventional power generation, it produces energy at the site of the end user, which eliminates line losses. CHP also provides benefits besides energy savings and resiliency and reliability benefits--it can continue to function in the event of a grid disruption. CHP should be a key element of the state's broader efforts to modernize its electric grid and make it more reliable. The General Assembly recognized the benefits of CHP in the 2018 omnibus energy bill which directs utilities to consider CHP as either a demand-side energy efficiency measure or a supply-side generation alternative. The regulation requires that CHP units over 25 MW that do not qualify for the industrial exemption purchase CO_2 emissions allowances for all emissions, including those associated with useful thermal energy (UTE). In the absence of a CHP system, the host would get its thermal energy from conventional methods, such as standalone boilers, which are not subject to the regulation. To avoid this disincentive for CHP, the regulation should exclude CO_2 emissions associated with UTE from a CHP unit. Emissions associated with thermal energy should be	Support for the proposal is appreciated. As discussed in the response to comment 51, DEQ believes the set-aside should be 5% in the early stages of the program; the set-aside may be revised at a later date as the state gains experience with the program and with the program DMME develops. In order to address CHPs with more clarity, the regulation has been amended to specify that the industrial exemption applies to fossil fuel CO_2 budget source located at a manufacturing facility that supplies less than or equal to 10% of its annual gross electrical generation to the electric grid, or supplies less than or equal to 15% of its annual total useful energy to an entity other than a manufacturing facility, provided that source had, prior to January 1, 2019, supplied both non-electric thermal energy to a manufacturing facility and 15% or less of its annual total useful energy to an entity other than a manufacturing facility. The unit's permit must contain a condition with the appropriate restriction of either gross electrical generation or

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	deducted from a qualifying unit's total emissions allowances, as in Massachusetts' RGGI rule. The hallmark of a CHP system is that it produces heat and electricity from a single fuel source. Without a thermal exemption, the regulation undervalues the output of these systems. We commend DEQ for including an energy efficiency set aside, as such programs help consumers and businesses use less energy, reduce carbon emissions, and save money on energy bills. According to an Alliance for Industrial Efficiency analysis, if Virginia achieves a 1.5% annual energy savings target, the state can reduce annual CO_2 emissions by 2.6 million tons in 2030 and save businesses $4.1 billion in cumulative cost savings from avoided electricity purchases. Increasing the set-aside from 5% to 10% would create additional opportunities for energy efficiency programs and help capture more carbon reduction benefits. For example, EPA's guidance document on Establishing an Energy Efficiency and Renewable Energy Set-Aside in the NO_X Budget Trading Program recommends a set-aside of 5-10%. We recommend that DEQ clarify that energy efficiency includes CHP and would be eligible for set aside funds. Although DEQ has previously categorized CHP as a near-term energy solution to enhance energy efficiency, listing CHP incentives explicitly as eligible for set aside funds would ensure that potential project hosts are aware of the definition.	useful thermal energy.
75. Dwight Alpern	I support the proposed rule. I was the attorney-advisor for EPA's Clean Air Market Division and involved in developing regulations for allowance trading programs, including the Acid Rain Program and NO_X SIP Call. I suggest revisions to facilitate program operation and achievement of CO_2 reductions. 1. The proposal does not explain clearly how a holder of a public contract with DMME would set up and operate a conditional allowance account. The function of such an account would be similar to that of any general account established by other persons, i.e., holding and transfer of CO_2 allowances. Neither account's function would include holding allowances for compliance. The simplest approach would be to revise the rule to clarify in 9VAC5-140-6020 C that accounts for handling conditional allowances are a type of CO_2 Allowance Tracking System account (in revised definitions of "CO_2 Allowance Tracking System" and "CO_2 Allowance Tracking System account") and that those accounts of holders of public contracts with DMME (but not of CO_2 budget sources) are general accounts (in a revised definition of "general account"). This would make applicable to the public contract holders' accounts the general-account	Support for the proposal is appreciated. The commenter correctly notes that the proposed rule does not explain how a holder of a public contract with DMME would set up and operate a conditional allowance account. This process will be determined by DMME in accordance with DMME procedure. Because this process will be governed by DMME, it is more appropriately addressed by DMME and not in this regulation. With respect to allowances usable for compliance, the definition of an allowance has been modified such that it covers any other state participating in the

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	provisions, e.g., for applying for an account and selecting and changing an authorized account representative, alternate, and electronic submission agent. Conforming revisions should be made to 9VAC5-140-6220 A, 9VAC5-140-6230 A, 9VAC5-140-6240, and 9VAC5-140-6250 A and B. For example, proposed 9VAC5-140-6230 A should be revised to read: Upon receipt of a complete account certificate of representation under 9VAC5-140-6110 or subsection B of this section, the department or its agent will establish a conditional allowance account and a compliance account for each CO_2 budget source or ~~and~~ a conditional allowance ~~compliance~~ account for a holder of a public contract with DMME for which the account certificate of representation was submitted. 2. The proposal requires Virginia CO_2 budget sources to hold "CO_2 allowances" for CO_2 emissions (9VAC5-140-6050 C 1 and 2 and 9VAC5-140-6260 B) but defines the term "allowance" (9VAC5-140-6020 C) by referring only to the Virginia CO_2 Budget Trading Program. That definition should be expanded to include CO_2 allowances issued by any other state participating in the RGGI program. If DEQ also decides to allow Virginia CO_2 budget sources to use for compliance offset allowances issued by any participating state, the same limitations on the use of offset allowances by other RGGI states' sources should apply to Virginia sources, i.e., limited use to cover emissions and no use for excess emission deductions. If offset allowances are to be usable, the following revisions are suggested: 9VAC5-140-6260 1. The CO_2 allowances, other than CO_2 offset allowances, are of allocation years that fall within a prior control period, the same control period, or the same interim control period for which the allowances will be deducted. ***3. For CO_2 offset allowances, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an interim control period may not exceed 3.3% of the CO_2 budget source's CO_2 emissions for that control period, or of 0.50 times the CO_2 budget source's CO_2 emissions for an interim control period, as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) of this part and Article 8 (9VAC5-140-6330 et seq.) of this part. 4. The CO_2 allowances are not necessary for deductions for excess emissions for a prior control period under subsection D of this section. 9VAC5-140-6260 C 2. The department or its agent will deduct CO_2 allowances for a control period from the CO_2 budget source's compliance account, in the absence of	trading program.

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	an identification or in the case of a partial identification of available CO_2 allowances by serial number under subdivision 1 of this subsection, as follows: i. First, subject to the relevant compliance deduction limitations under subsections A and D of this section, CO_2 offset allowances. CO_2 offset allowances shall be deducted in chronological order (i.e., CO_2 offset allowances from earlier allocation years shall be deducted before CO_2 offset allowances from later allocation years). In the event that some, but not all, CO_2 offset allowances from a particular allocation year are to be deducted, CO_2 offset allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances. ii. Second, any ~~Any~~ CO_2 allowances, other than CO_2 offset allowances, that are available for deduction under subdivision 1 of this subsection. CO_2 allowances shall be deducted in chronological order (i.e., CO_2 allowances from earlier allocation years shall be deducted before CO_2 allowances from later allocation years). In the event that some, but not all, CO_2 allowances from a particular allocation year are to be deducted, CO_2 allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances. 9VAC5-140-6260 D 1. After making the deductions for compliance under subsection B of this section, the department or its agent will deduct from the CO_2 budget source's compliance account a number of CO_2 allowances equal to three times the number of the source's excess emissions. In the event that a source has insufficient CO_2 allowances to cover three times the number of the source's excess emissions, the source shall be required to immediately transfer sufficient allowances into its compliance account. No CO_2 offset allowances may be deducted to account for the source's excess emissions.	
76. Americans for Prosperity	The regulation requires electric generators to purchase allowances to emit CO_2 in the RGGI cap-and-trade program. These allowances are equivalent to permit or license fees. In addition, the regulation delegates 5% of the allowance proceeds to DMME for CO_2 reduction projects. The Constitution of Virginia establishes authority to raise and spend money to the General Assembly, not DEQ (Article IV, § 11 and Article X, § 7). The regulation adopts the RGGI Model Rule, model legislation which has been adopted by the legislatures of all participating RGGI states. The General Assembly clearly opposes adoption of a CO_2 cap and trade program without legislative approval. The Senate and House passed HB1270 resolving that no CO_2 cap and trade program be adopted without authorization. In addition, the Senate Agriculture, Conservation and Natural Resources Committee rejected SB696, which	To characterize the issuance of an allowance as a permit or license fee is inaccurate; see the response to comment 62. Facilities have always incurred costs as they have been required to meet legal mandates to control and reduce pollution. Under a cap-and-trade program, facilities have enhanced flexibility to manage these compliance costs based on their specific business needs.

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	would establish cap-and-trade in Virginia and bring the state's regulations into compliance with the RGGI model rule. The proposed regulation will not withstand a legal challenge.	As discussed in comments 139 and 159, it is necessary and appropriate for the board to promulgate state-specific regulations controlling carbon pollution. The board's legal authority to issue regulations controlling air pollution is found in the Code of Virginia at §§ 10.1-1306 through 10.1-1308; the Office of the Attorney General of Virginia issued an official advisory opinion on May 12, 2017, which concluded that the board is legally authorized to regulate carbon pollution under these sections of the code. While the board has broad authority to control air pollution, it is also responsible for achieving this goal in the most effective and cost-effective means possible, and, in the case of carbon pollution, this goal is most readily achieved through implementation of a cap-and-trade program. Cap-and-trade programs are proven means of reducing air pollution (see, for example, the response to comment 48); they incentivize pollution reduction. Unlike a "command-and-control" approach that would simply impose specific pollution control requirements, the trading approach maximizes the ability of a facility to flexibly make favorable business decisions while meeting the primary goal of reducing air pollution. The board furthermore has the authority to maximize the efficiency and efficacy of a

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		cap-and-trade program by linking the program with RGGI rather than attempting to establish a new and untried state-only system. There is nothing novel about Virginia's participation in a cap-and-trade program; indeed, the Commonwealth has participated in such programs since EPA established the Acid Rain Trading Program under Title IV of the 1990 amendments to the federal Clean Air Act. Currently, Virginia is operating under the latest iteration of EPA's trading program for the control of NO_X under CSAPR. Nor is there anything novel about the regulation of carbon pollution in Virginia. Virginia's greenhouse gas permitting regulation (9VAC5-85) has been in place since 2011.
77. Americans for Prosperity	The RGGI program has not worked to reduce CO_2 emissions. CO_2 emissions fell just as fast in states with similar energy policies except for RGGI as they did in RGGI states according to "A Review of the Regional Greenhouse Gas Initiative" (Cato Journal 2018). Lower natural gas prices and EPA regulation encouraged fuel switching from coal to natural gas between 2007-15. This resulted in a 16% reduction in coal-fired electric generation, and a corresponding increase in natural gas generation of about 10% in RGGI and non-RGGI states. The same report shows non-RGGI states added generation from wind, and solar power at over twice the rate as RGGI states (5.5% compared to 2.3%). Non-RGGI states also saw a faster rate of improvement in energy intensity, a measure of energy efficiency (11.5% compared to 9.6%). RGGI, Inc. claims allowance revenue was invested in energy efficiency, and wind and solar power, but the actual comparison results show no significant impact of the investments. Compare non-RGGI Virginia to the combined results in neighboring RGGI states of Maryland and Delaware. All three are in the PJM Interconnection Regional Transmission Organization. The extra costs of RGGI	The RGGI program has been very successful at reducing emissions in participating states. Current emissions are approximately 45% lower than where RGGI started. Commenters argue that RGGI did not bring about the reductions but offers no evidence to demonstrate that RGGI did not cause—or at least contribute—to the emissions reductions in the RGGI region. While the electricity system is complex and it is difficult to separate out specific causes, adjustments to the RGGI program over the years have reduced the RGGI cap, preventing emissions from increasing and locking in reductions.

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	allowances discouraged electric generation in Delaware and Maryland where electricity imports grew 42% since 2005, while Virginia imports decreased 34%. In other words, the RGGI states simply exported electric generation and emissions to other states. Adjusting for those exported emissions, emissions rates per person fell 38.6% in Virginia since 2005 compared to a combined 37.1% for Maryland and Delaware. Importing more power from other states is not the only form of emissions leakage. RGGI allowance costs added to already high regional electric bills. The combined pricing impact resulted in a 12% drop in goods production and a 34% drop in the production of energy intensive goods. Comparison states increased goods production by 20% and only lost 5% of energy intensive manufacturing. The extra costs of RGGI allowances have turned coal-fired plants from base load providers to intermittent suppliers by dramatically lowering operating hours. Expected increases in RGGI emission allowance cost will soon have the same impact on natural gas-fired power plants. Ramping power plants up and down has dropped efficiency 18.5% which results in more emissions, not less, and further raises electricity costs. 61% of Virginia power generation comes from coal and natural gas. A national target of 28% lower emissions from power plants by 2025, and 32% by 2032 from a 2005 base established in the Clean Power Plan will be met without taxes or fees on CO_2 emissions. Over the most recent 12 months power plant emissions have already fallen 27%. The U.S. leads the world in reducing emissions. Since 2005 the U.S. has reduced CO_2 emissions twice as fast as the rest of the developed world combined. Clearly RGGI has not had the expected impact of lowering CO_2 emissions. Benefits calculated in the Economic Impact Analysis assumed the regulation would lower CO_2 emissions along with reducing SO_X and NO_X as a byproduct. A decade of experience with RGGI has shown no added reduction in CO_2 or air pollutant emissions from the RGGI program; therefore there can be no monetized benefits from the proposal. To calculate the costs of the regulation an estimate of tons of annual emissions through 2030 is needed, along with an estimate of how many allowances will be available (each allowance covers one ton of emissions), and an estimate of the future price of allowances. Fortunately, the proposal provides the last two items. The SCC files an annual "Status Report: Implementation of the Virginia Electric Utility Regulation Act." The state's two largest investor owned electric utilities Dominion	This stands in stark contrast to analyses of uncapped areas of the country where emissions are expected to remain flat or slightly increase into the future. In addition to these demonstrable emissions benefits, as discussed in the response to comment 61, the RGGI program has greatly benefited local and regional economies. DEQ continues to believe that the studies and analyses developed on its behalf as well as additional information provided by RGGI and other experts in the field demonstrate that linking to RGGI will benefit the Commonwealth by cost-effectively reducing carbon pollution and stimulating clean energy growth. See comment 136 for more information on how RGGI's market mechanisms work and how they will operate in Virginia. Note that CO_2 intensity is decreasing across the RGGI region in spite of increased generation. With regard to costs incurred as a result of the CCR, the consignment auction approach means that ratepayers only bear the cost of excess allowances needed to comply.

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	Energy and Appalachian Power file annual Integrated Resource Plans (IRP) which forecast future demand, supply, and pricing. Based on these documents there are planned retirements between 2017-26 of 1731 MW of oil and coal-fired capacity, and 440 MW of natural gas capacity. Between 2017 and 2019 5413 MW of new natural gas-fired capacity has already been approved by the SCC. Natural gas emits about half the CO_2 for each MWh of power generated. The retirements could be considered as offsetting emissions from 4280 MW of new natural gas capacity. That leaves a net increase of 1132 MW of new natural gas capacity. If that new capacity operates 5000 hours a year it will generate about 2.5 million tons of added CO_2. New power plants should yield less expensive power and run more hours than the older replaced plants, meaning higher emissions. Some of the retiring power plants will continue to operate after the new plants start up meaning higher emissions. Appalachian Power and Dominion own out-of-state power plants, and could shift generation out of state, meaning lower Virginia emissions, but global emissions would remain the same. The RGGI states review the program every 3 years and have worked to raise the allowance price each time, so it is likely allowance prices will rise. All of these factors will be ignored in favor of a conservative emission forecast adding 2.5 million tons to the 36.6 million tons emitted in 2016, for a total of 39.1 million tons in 2020. The proposal commits 5% of allowances for sale by DMME with the allowance revenue to be spent on CO_2 reduction projects. The Economic Impact Analysis forecasts an allowance price very close to the proposed ECR trigger price which subtracts allowances offered in an auction if the price goes below the trigger price. Our analysis uses the ECR trigger price as the forecast price. An upper range would use the CCR trigger price which runs about twice the ECR trigger price. If the CCR trigger price is exceeded extra allowances are added to the auction. From 2013-15 the CCR acted as a price signal in the auctions. The forecasted cost assumes power companies chose buy the emission allowances they need to comply to maintain electric grid reliability. The alternative is to write off premature closing of existing plants, while paying premium prices for new zero or low emission generation sources. This is likely as Dominion expects demand to grow 24% by 2030 and will need the capacity. The SCC allows utilities to pass on the cost of meeting environmental requirements and would likely allow the pass through of allowance costs. There is no penalty other than allowance cost if a state misses its RGGI target. The total Net Present Value cost through 2030 of	

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	the regulation is $674 million with no offsetting benefits. The cost would be twice as high if the CCR trigger price sends the expected price signal to the auctions, so the range of cost is $0.7-1.4 billion. In 2030, the program will add $182 million, or about $20 a year to residential electric bills. Industrial bills could rise by over $100,000 a year.	
78. Business Council for Sustainable Energy (BCSE)	A regulation to reduce and cap CO_2 through a multi-state trading program makes sense for Virginia. Capping carbon from generation facilities will incentivize the use of cleaner energy resources that promote economic development and job creation in the state. Trading within a larger group of states will allow for greater market efficiency and lower compliance costs. The state will need to use the full portfolio of clean energy technologies and services, including energy efficiency programs that reduce energy consumption, cleaner burning natural gas, and renewable energy resources. BCSE supports the updating output-based allocation structure. DEQ should encourage the use of set asides granted to DMME to support of the full suite of clean energy technologies, including both supply-side and demand-side energy efficiency measures. RGGI states have benefitted from investing the multiyear funding from auction proceeds in clean energy, and BCSE encourages DEQ to consider a larger set aside amount.	Support for the proposal is appreciated, particularly support for the updating output-based allocation structure. As discussed in the response to comment 51, DEQ recognizes the value of energy efficiency programs as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement the set-aside. DEQ believes the set-aside should be 5% in the early stages of the program; the set-aside may be revised at a later date as the state gains experience with the program and with the program DMME develops.
79. Biomass Power Association	Biomass accounts for a significant portion of Virginia's renewable fuels makeup. As of 2015, biomass represented the bulk of renewable power available in the state. We commend the board for pursuing the CO_2 trading program. Only through programs like these can we seriously address the threat of climate change. By supporting a rich combination of power sources, a state can advance goals in other areas like forest management, watershed management, economic development, and transportation. The regulation would apply only to fossil fuel fired-facilities, exempting biomass power. We urge Virginia to maintain this position. Aside from supplying the state with a significant portion of its carbon neutral electricity generation, biomass is a critical part of the forestry supply chain. Biomass power facilities purchase the leftovers that remain following the harvest of a forest for higher-value wood fibers, adding value to the entire supply chain. The wood fibers used to generate biomass power are typically unusable for other wood products, and emit methane during decomposition.	Support for the proposal is appreciated. See the response to comment 67 for further discussion of biomass.

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	The Association commissioned a study to determine the extent of carbon savings that can be achieved by opting for biomass over natural gas. A report is available on our website. The study examined the carbon intensity of a 50 MW capacity biomass power facility with a 43 MW net output on the electric grid, comparing it to that of a typical combined cycle natural gas facility. The study found that the use of organic residues as fuel in a biomass power plant instead of natural gas in a combined cycle facility results in immediate carbon savings of 115%, with 98% carbon savings over 100 years. Like the majority of biomass power facilities in the U.S., the subject of the study uses organic residues to generate power supplied to the grid. The fuels used at this facility are residues left over from harvesting fiber for local lumber and paper mills. These low-value materials are generated whether they are used for power or left to decay. If not used by biomass power plants, the materials typically remain in the forest as slash piles. The avoidance of carbon and methane emissions by removing and using materials that decay results in a significant GHG reduction over time. While the decay of these materials releases small amounts of methane consistently over time, methane has a 21 times higher global warming impact on the climate than CO_2. Further, with federal incentives for carbon capture and sequestration, and rapid technological advances being made in this area, biomass with carbon capture can become one of the only viable techniques that allows for the removal of atmospheric carbon. While the technology is still developing, we are optimistic that our members will soon be able to contribute to reducing the impacts of climate change in an even more meaningful way. Biomass is an essential part of any carbon reduction program.	
80. Blue Ridge Environmental Defense League (BREDL), Food and Water Watch, People Demanding Action, Preserve Floyd, Renewable Energy and Electric Vehicle Association	The excessively high RGGI cap and low allowance clearing prices, combined with other flaws in the program, prevent RGGI from being stringent enough to drive any meaningful reductions in CO_2. RGGI is a weak program that has allowed power plants to emit on a business-as-usual basis. For the first 5 years of the program, the industrywide cap was set over 50% higher than actual emissions. This meant fossil fuel power plants did not need to do anything to meet the overly generous cap. The initial cap allowed power plants to bank a substantial amount of unused allowances, amounting to 140 million tons of CO_2. While the cap was adjusted to address these saved allowances, this allowance surplus could continue to grow significantly due to a cap that continues to be higher than actual emissions, low allowance clearing prices, the purchasing of all available allowances and other factors. This further limits the effectiveness of the program.	The commenter suggests that RGGI allowance prices have been too "low" to drive emissions reductions. As of July 2018, RGGI allowance prices have remained between $2-4 for 70% of the auctions to date, and allowance prices have never reached $8 per ton. At the same time, emissions in RGGI have been steadily declining at a pace that exceeds the rate of decline of the RGGI emissions cap. Given the complexity of the electricity markets, it is difficult to

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	The CCR further disincentivizes emissions reductions by operating as a cushion by releasing additional pollution allowances on top of the cap if prices get too high. The CCR was triggered in 2014 and 2015, allowing 5 million and 10 million additional allowances to be sold. All of these allowances were purchased, and because they were not borrowed from future years, they essentially increased the cap. RGGI prices, including the reserve price, continue to be too low or too volatile to result in any meaningful carbon reductions. Most, if not all, of the current carbon markets have failed to create "a stable, market-driven price of carbon," and often prices for GHG allowances "have been so low as to create little incentive to invest in GHG reduction," according to researchers at the University of California. Structural flaws in the RGGI program prevent the purported market-based incentives from working. Moreover, polluters prefer a larger supply of low-priced pollution allowances, creating a disincentive to actually embrace a pollution price point that might be effective. No market-based pollution trading scheme will ever result in market prices sufficient to encourage all polluters to reduce their emissions. RGGI has not accounted for increased emissions of methane from the growth of fracking and natural gas infrastructure. The climate proponents and petroleum industry that favor natural gas contend that since gas-fired plants emit less CO_2 than coal-fired plants, replacing coal power plants with gas power plants reduces climate emissions. However, methane emissions throughout the natural gas supply chain can nullify or even reverse any climate benefits from switching from coal-fired. RGGI's climate projections also ignore the reality that natural gas emits more CO_2 than coal. Declining CO_2 emissions from coal-fired power plants and coal-related methane emissions have been exceeded by increases in CO_2 from natural gas-fired power plants and methane leaks related to the gas used to fuel the power plants. RGGI drives demand for new gas-fired power which provide symbiotic profit opportunities for power companies that are capitalizing on low gas prices and fracking companies that hope the new plants will soak up supplies and ultimately raise prices enough to encourage more drilling. The Department of Energy reported that more than 420 new gas-fired power plants were proposed for construction between 2017-21. The demand for gas-fired electricity generation increases the demand for fracking and natural gas infrastructure, which further expands methane emissions.	discern the precise cause of the RGGI emissions decline in a given year or years. One econometric analysis carried out by economists at Duke University concluded that the RGGI price has indeed been a principal reason for the emissions reductions seen in the RGGI region. This suggests that even at prices between $2-4 RGGI is driving emissions reductions contrary to the commenter's suggestion. Apart from the RGGI price signal, it is clear that adjustments to RGGI's cap from time to time have locked in the emissions reductions that have been realized in the RGGI electricity sector. The commenter suggests the RGGI cost-containment reserve (CCR) has a negative impact on emissions reductions. The CCR threshold is currently set at $10, meaning that allowance prices would have to reach $10 a ton in a given auction for the CCR to be triggered. The auction clearing price for the June 2018 RGGI allowance auction was approximately $4—far below the CCR threshold. As mentioned above, RGGI allowance prices have never exceeded $8 per ton. Low allowance prices mean lower overall program costs before taking into account the mitigating impact of allocated allowances to consumer benefit. RGGI has locked in meaningful emissions reductions on the order of 45-50% since 2009, while simultaneously

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		keeping allowance prices low. In essence, the RGGI program has achieved its program goal: controlling carbon pollution in a cost-effective and efficient manner. As discussed elsewhere, CO_2 is a global and national problem. RGGI stands for the proposition that a group of states can have a positive impact on emissions without driving emissions allowances up over $8 to date. This effectively balances the need to reduce emissions with the need to keep program costs at a reasonable level. Detailed discussion of how the consignment auction and market mechanisms operate, as well as the benefits of this approach, is available at comments 108 and 136. Executive Directive 11 directs DEQ to "1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that: a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states

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		with such limits." (Emphasis added.) In other words, the proposed regulation under consideration is designed to meet the Governor's mandate to control CO_2 via participation in an emissions trading program. This emissions trading program is RGGI and, as the commenter states, RGGI does not address methane. DEQ agrees that the control of methane emissions is important; however, this specific regulatory action is not the means by which that will be accomplished. Note that methane is controlled elsewhere in the board's regulations as appropriate, and other measures may be adopted at a different time and in compliance with federal Clean Air Act and state law. As discussed elsewhere, emissions trading programs are authorized under the federal Clean Air Act and are a proven means of reducing air pollution (see, for example, comment 37). Joining RGGI will impose additional controls on each source of pollution beyond technology-based emissions controls imposed by federal and state permitting programs. Note that RGGI specifically addresses CO_2, not methane. More information on benefits realized by RGGI is discussed elsewhere; see, for example, comments 61 and 108.
81. BREDL et al.	Because biomass is typically considered renewable under state renewable standards, RGGI does not count CO_2 emissions from biomass processing and combustion. This underestimates the amount of carbon	As discussed elsewhere, the focus of this regulation is the control of CO_2 from fossil fuel-fired generators;

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	released from this energy source by a significant amount. There is a growing consensus that biomass cannot be considered carbon neutral. Processing, transporting and burning wood at biomass plants all produce GHG emissions, which can be greater than those from coal. Carbon sequestration from the growth of woody material takes decades to occur and is counteracted by the rapid clearcutting of forests to fuel wood-fired power plants. If biomass CO_2 emissions were counted in RGGI states, total RGGI CO_2 emissions could be on average 31% higher than what is currently projected over the next 10 years. This would also undercount the CO_2 emissions from Virginia's rapidly growing biomass industry. From 2011-16, electricity generation from biomass more than doubled in the state. In 2016, 2.60% of Virginia's power came from biomass, nearly 50 times Virginia's energy generation from wind, solar and geothermal energy combined. By not counting these emissions, RGGI would promote the growth of biomass, increase harmful pollution, and suppress the expansion of genuine renewables like solar.	see the response to comment 67 for additional information.
82. BREDL et al.	RGGI proponents argue that emissions have fallen under RGGI. While CO_2 emissions have declined during the time that RGGI has been in place, there is no indication that RGGI itself has driven these reductions. Those reductions were more likely attributable to the Great Recession than to the program, since RGGI went into effect in 2009 as the economic activity declined steeply. Emissions were already declining before RGGI went into effect; emissions fell faster before RGGI was implemented. Much of the alleged effectiveness of RGGI is attributable to a massive countrywide shift away from coal and oil to natural gas that was already underway when RGGI took effect in 2009. Overall, from 2005-15, coal and oil use decreased from 32% to 9% of electricity production in RGGI states, while natural gas--which has become significantly cheaper because of the risky fracking boom--increased from 25% to 42%. RGGI effectively promotes the expansion of fracking for natural gas at the expense of renewables. From 2009-16, RGGI states have added 4 times more gas-fired electricity generation than wind and solar generation. The percentage of electricity from natural gas-fired power plants rose by 11.2% from 2009-16 but only rose 2.4% from wind and solar. Natural gas-fired power plants have relied on fracking which benefits power companies but imperils communities. Oil and gas operations have become the second greatest global source of the methane. RGGI further encourages the shift to fracked gas because CO_2 is the chief GHG pollutant emitted from coal-burning power plants. If a power company shifted its energy mix from coal to natural gas, it would accumulate RGGI allowances. While shifting to natural gas results in much lower CO_2 emissions at the power plant, the	As noted in the response to comment 80, it is difficult to determine the precise factors that lead to a specific result in complex electricity markets. One study carried out by economists at Duke University concluded the RGGI program was in fact a significant factor on the emissions reductions realized in the RGGI region. Other factors, such as low natural gas prices, also played a role. Without a doubt, the RGGI program has effectively locked in emissions reductions of approximately 45-50% since the program began through cap adjustments. Thus, RGGI has been very effective in realizing emissions reductions from power plants in the RGGI states. RGGI is a flexible, market-based program that imposes an allowance cost on burning fossil fuels, including natural gas. It therefore tends to

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	increased reliance on natural gas significantly amplifies methane emissions. RGGI's failure to consider or cap methane as a GHG allows RGGI states to overestimate climate benefits. The GHG footprint of natural gas is worse than coal and oil because methane traps more heat in the atmosphere. Utilities that switch from coal to gas reduce CO_2 smokestack emissions but could be increasing CO_2 equivalent GHG emissions from methane leaks.	discourage electricity generation from natural gas relative to lower carbon sources of electricity such as wind and solar that have no allowance cost. It is wrong to suggest that RGGI promotes natural gas use over renewables. Also note that not all of the energy shift under RGGI has been to natural gas; shifts to renewable energy and energy efficiency are occurring and on the increase in RGGI and Virginia. For example, implementation of the Grid Transformation and Security Act of 2018 will encourage renewables. The set-aside will also encourage the development of renewable and efficiency projects. See the response to comment 51 for further discussion.
83. BREDL et al.	Cap-and-trade programs have the potential to form pollution hotspots and harm vulnerable communities. These populations already face higher pollution exposures because of the disproportionate location of toxic facilities in their neighborhoods. Market-based environmental policies can exacerbate hotspots that remain outside the scope of trading schemes, and they worsen pre-existing health and socioeconomic disparities. RGGI supporters point to the program's ability to raise revenue for renewable energy and energy efficiency initiatives, as well as reduce energy bills for low-income households. However, many states have used this pollution payment scheme to balance state budgets. While governments need revenue, funding from pollution means that governments will be less inclined to eliminate carbon from industry as they become dependent on the revenue. RGGI proponents assert that the program will save households millions of dollars in electricity rates. This has not been the case. RGGI states' residential consumers have seen their bills go up $1.1 billion since the program was implemented. At the same time, industrial users have seen a $1.9 billion decrease in their electricity bills.	DEQ is committed to addressing the environmental and health impacts of power plants in all communities, including those communities that have historically borne a disproportionate burden from local air pollution sources. The goal of the program is to reduce carbon emissions from power plants using a tool that has proved effective at reducing air pollution at the lowest possible cost. The emissions cap is designed to ensure that carbon emissions are reduced from a baseline, meaning that overall the environmental situation is improved from the baseline. Based on the modeling carried out for the proposal, not only would the program reduce carbon

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		emissions, but it will also produce co-benefits in the form of reductions in other harmful pollutants that contribute to low-level ozone and particulate pollution. This is good for the health of Virginians. The commenters are concerned that because the program does not require emissions reductions at specific plants it may not reduce emissions at plants in specific neighborhoods. Individual power plants are subject to facility permits that hold those plants to specific emissions limits designed to protect public health. As discussed in comments 48 and 136, cap-and-trade programs are effective pollution control programs that reduce emissions beyond permitting controls. It is important to note that Virginia is a regulated state in which costs are carefully monitored and managed by the SCC. The program is not raising revenue; the consignment approach ensures that benefits return to the ratepayers, and no funds of any kind will be available for uses other than emissions reductions. The most recent economic analysis found, that from 2015-17, RGGI lowered CO_2 emissions while benefiting local and regional economies.
84. Birchwood Power Partners, L.P.	Birchwood Power operates a 240 MW coal-fired cogeneration facility in King George County. Birchwood is equipped with state-of-the-art pollution controls, including low NO_X burners, over-fired air, and selective catalytic reduction to reduce NO_X; use of high quality, low sulfur bituminous coal and a flue gas desulfurization system with a dry lime scrubber to control SO_2; and a high efficiency fabric filter baghouse to control particulate	The commenter's concerns are appreciated. DEQ is assisting affected sources in managing compliance costs by issuing allowances. The amount of compliance cost covered by the allowances will

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	matter. Birchwood provides the advantages of fuel diversification, high energy efficiency, and low emissions, and is located in relatively close proximity to load. This combination makes Birchwood an important tool for balancing grid reliability and environmental protection. Birchwood is one of the few remaining coal-fired power plants in Virginia. In 2005, coal-fired power accounted for approximately 34.6 GWh or about 46% of in-state electricity generation. By 2012, coal-fired generation in Virginia was reduced to 13.6 GWh, about 20% of in-state generation. During the same period, generation from natural gas-fired combined cycle plants increased from 7.3 GWh, 10% of in-state generation, to approximately 23 GWh, 35% of in-state power generation. Further retirements of coal plants and construction of new gas plants are underway. The 2014 Virginia Energy Plan lists Birchwood as a coal-fired plant with projected long-term operations, and it is the only such plant that operates as an independent power producer (IPP). Coal-fired generation is important for maintaining fuel diversity and reliability. Birchwood is dispatched during extreme weather events and peak power demand periods. During Polar Vortex events in 2014 and 2015, natural gas that might have been available for power generation was consumed by residential and commercial customers for heating or, if available, became very costly. The Birchwood plant, with an on-site fuel stockpile, was dispatched at a high capacity factor and was 100% available for dispatch. Birchwood is particularly important to maintaining reliability as it is located close to the Washington D.C. and northern Virginia area and can provide fuel diversity in the face of gas shortages or price spikes. Birchwood's sale of energy is currently contracted to a third-party and is unable to pass the costs of the proposed regulation through to the market. Although Birchwood will be able to include these costs in its price of energy after its contract expires, the economics of coal-fired power plants have been severely impacted by the glut of natural gas, which has reduced energy margins and dispatch of the facilities. The regulation will put further pressure on the viability of these critical assets. Birchwood urges DEQ to adopt an approach that preserves a diversified fleet of power plants using different fuels. Diversification of the types of electricity generation sources will help maintain grid reliability during situations where there are natural gas curtailments, periods when renewable energy is limited or not available, and other events impacting individual base load units in Virginia.	depend on business decisions made by any individual facility.

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	Birchwood's allocation will be based upon the average generation of the years 2016, 2017, and 2018. During this period, Birchwood's dispatch was at a historical low that represents only approximately 25% of its potential generation, due to the low price of natural gas. As an IPP, Birchwood would be severely disadvantaged based upon the proposed allocations of emission allowances. Accordingly, selection of a different period would more accurately represent dispatch of Birchwood.	
85. Blue Ridge Power Agency (BRPA)	The commenting members (Towns of Bedford and Richlands; Cities of Danville, Martinsville, Radford, Salem; Virginia Polytechnic Institute and State University; Central Virginia Electric Cooperative) are concerned that the board may lack statutory authority to participate in RGGI. Legislatures in most RGGI states have passed authorizing legislation. These legislatures have determined that because RGGI is a reflection of state policies and will require citizens to bear a cost to achieve those policies, those elected by the citizens of those states should make the decision as to whether joining RGGI is justified. Virginia, on the other hand, is acting without the benefit of legislative direction. Governor McAuliffe directed the board to implement RGGI. Without any support other than saying that it is "well settled," Attorney General Mark Herring determined that GHGs fall within the definition of air pollution under Virginia law. To avoid the uncertainty of protracted litigation and to ensure support for the program, the board should defer action until the General Assembly approves participation and authorizes DEQ to administer carbon-reduction programs.	As discussed in the response to comment 76, it is necessary and appropriate for the board to promulgate state-specific regulations controlling carbon pollution. See also comments 139 and 159 for further discussion.
86. BRPA	The rule would not require generators to purchase emissions allowances from the state in an auction, thus avoiding a requirement that all revenue-raising measures must be approved by the General Assembly. Instead, generators would be freely allocated allowances, which they consign to the RGGI auction. Allowances purchased at the RGGI auction would no longer be conditional, i.e., generators would surrender these allowances to DEQ in order to cover their actual annual CO_2 emissions. For each conditional allowance consigned to auction, the generator would receive the clearing price of the auction. This process allows generators to consign all of their conditional allowances but only purchase what they actually need. Unneeded allowances would be sold, with the proceeds collected by the generator. The program does not address the treatment of these windfall proceeds and, importantly, contains no provision specifying how such windfalls would be returned to consumers. The impact of the program on monthly customer bills is not reliable, and the impacts are likely to be considerably higher. The regulation preamble suggests that the	To date all emissions trading programs implemented by Virginia have allocated emissions allowances to the compliance entities. This is consistent with the approach recommended repeatedly by EPA in the various federal model rules offered for implementation by states beginning with the NO_X Budget Program in the late 1990s. This program will similarly allocate allowances to compliance entities. The program does two things that address the concerns voiced by the commenter. First, compliance entities will

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	average monthly bill impact for residential, commercial, and industrial consumers through the year 2031 will be nominal--never more than 1.1%. These estimates are taken from an impact analysis prepared by a consultant that assumes that "95% of revenues that accrue to utilities from the sale of carbon allowances or credits are returned to ratepayers." No factual basis exists upon which to base an assumption that 95% of the revenues accrued would be returned to customers. As DEQ recognizes, the "revenue received by CO_2 Budget Sources owned by regulated electric utilities flow to rate payers pursuant to SCC) requirements." However, there is no legislative or other mandate to require the SCC to impose such a requirement on regulated utilities. The outcome of any proceeding at the SCC contemplating a proposal to direct the regulated utilities to return RGGI windfalls to customers is uncertain. Relying on the presumed outcome of an action that may or may not be taken by a different regulatory agency as the basis for cost estimates is speculative. The cost estimates developed by The Analysis Group fail to take into account that a significant share of the covered generators are not subject to SCC jurisdiction. Approximately one-third of the energy produced in Virginia in 2015 was generated by facilities owned by IPPs., which are not regulated by the SCC and would not be subject to any regulation that may be adopted later by the SCC. These facilities sell power into the regulated wholesale markets, and those sales are subject to the exclusive jurisdiction of FERC. The consultant's study assumes that "revenues from allowances to independent power producers [would be treated] in the same way as those allocated to utilities (i.e., revenues returned to ratepayers)"; however, no state mechanism exists to assure that the benefits of allocations to IPPs actually accrue to ratepayers. The program would allow these facilities to make windfall profits off of their allocated share of RGGI allowances, and permit those profits to lay beyond the jurisdictional reach of the state's rate regulator. Surely this approach is contrary to the program's intent. The board should explain why customer bill impacts should not be adjusted to remove revenues from allowances to unregulated entities, or explain what regulatory mechanisms would assure those revenues are returned to customers. The RGGI model rule leaves how to allocate allowances to states. Under the proposal, allowances will be allocated to units based on the average of the 3 amounts of the unit’s total net-electric output during the 3 most recent years for which data are available prior to the start of the control period. All covered units in Virginia, regardless of whether they are regulated by the SCC, will receive an allocation of allowances based on past	consign their allocated allowances to auction, where the allowances will be sold. Unlike previous programs, this means that the value of the allowances will be transparently known to all observers of the auction. This, in turn, means that the utility commission will have a clear valuation of the allowances to use in carrying out their responsibilities. Second, the allocations are to be made on an updating, output basis. This means that the allocation will tend to reflect the facts in the field: the plants that run more will get more allowances and the plants that run less will get less. This should greatly reduce the chances of an overallocation to individual plants. The commenter notes that independent power producers are not subject to rate regulation by the commission. To the extent the power generated by independent power producers is purchased by regulated utilities, however, the costs of that power are indeed the subject of regulation. This would include any embedded allowance costs. The commission, therefore, may have some influence over whether the costs of allowances are in fact passed on to consumers when the compliance entities have received the allocations at no cost to them. In any event, the program will make such regulatory decisions much easier than previous

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	operation and the right to potentially convert those allowances into profits. Note that no other state has chosen to allocate 95% of allowances to generators. The allocation of conditional allowances to generators based on historical usage is arbitrary, and likely to overcompensate generators and produce excess allowances because energy production at many of the covered units will continue to decline as zero-carbon resources compete with high-carbon emitters. These excess revenues will be sold at auction or banked by the generators, but those entities that have made investments in energy efficiency and carbon-reducing technologies are provided nothing. Further, the board has stated that the SCC will need to act to require that regulated utilities return auction revenues to customers. But until those rules are finalized there is no guarantee whether or how that will be done and there is a risk that the funds will become windfall profits to the recipients of allowances. It is also unclear as to how Virginia customers will receive any benefit from the profits earned by unregulated IPPs. An alternative to the allocation of allowances to units is to directly allocate allowances to load-serving entities (LSEs) in proportion to their customers' energy consumption. The value could be passed on to those customers by way of offsetting reduction to their bills, or the benefits of programs to invest in local alternative energy projects in their service territories. This approach would not foreclose the statewide set-asides of allowances to support energy efficiency programs. The commenting members therefore strongly urge the board to withdraw the regulation for the purpose of considering whether allocation of consignment allowances should be redirected from generating units to LSEs. The preamble does not explain how the program would impact the cost of wholesale power sold to Virginia entities, which it would assuredly do for BRPA's members. These impacts take effect at the wholesale markets regulated by FERC. With respect to power purchase contracts that include a formulaic type of cost-of-service rates, the cost incurred by the owners of covered generators of procuring RGGI allowances are likely to be passed through in those cost-based rates. However, it is not clear whether revenues from the auction for consigned allowances would be credited through the formula rate process and returned to our members. This is to be decided by FERC, and could leave members and consumers with the obligation to bear the costs of RGGI without any offsetting revenues. Energy prices could increase as the cost of RGGI allowances are incorporated into the energy offers that are submitted into the PJM energy markets. Energy prices in the regional markets are determined by the	emissions trading programs where allowance allocations were made without the benefit of a consignment auction or without updating. See, for example, comment 136. According to the bill impact analysis conducted on DEQ's behalf, costs are expected to be minimal.

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	offer of last-dispatched and highest-price resource, and because the auction is a single-price auction the generator's cost of RGGI allowances could have region-wide price impacts. Over time, the program would ratchet up the RGGI allowance price and ratchet down available quantity, so the cost of RGGI will become more apparent in wholesale market prices. BRPA members will see a more significant impact of RGGI on wholesale power costs. Participation in RGGI has the potential to affect congestion paid by our members. Wherever power is generated, whether in Virginia or another state, it must be moved financially from that location into the Blue Ridge. Regardless of the contract price, if the price of power at the point of generation in another state is low and the price of power in the Blue Ridge area is high, the purchaser must pay for the difference, and those costs can be substantial. We ask the board to reconsider the allocation of conditional allowances to generators. The Regulatory Advisory Panel was clear: cost to customers should be a primary consideration. In fact, the panel could not come to consensus on whether LSEs or generators should receive the auction credits. Assigning allowances to LSEs is the most direct way to assure that the benefits of RGGI accrue to intended beneficiaries--retail consumers in Virginia.	
87. Calpine	Calpine supports cap-and-trade programs that place a clear price on carbon emissions in a way that allows such a price to be reflected in wholesale power prices and that are designed to minimize market distortions, including broad coverage of new and existing power generation facilities that emit GHGs; effective and equitable methods for distributing emission allowances; minimization of leakage issues that result from differing requirements from one state to the next; and setting allowance budget caps at a level that will result in meaningful carbon reductions by incentivizing environmentally efficient dispatch of power generation facilities. For these reasons, Calpine supports the proposal, including allowing Virginia sources to use allowances that either originated in Virginia or any other RGGI state. Linkage with RGGI will allow for a broader, more flexible emissions market, helping to improve market competitiveness and trading efficiency while lowering carbon abatement costs for affected generators. Because Virginia's linkage with RGGI will significantly expand the size of the RGGI market, it is important to recognize the potential impact of the level of Virginia's base budget on the RGGI program and on allowance prices. A budget that is not based on reasonable assumptions regarding the generation mix in light of a cap-and-trade program in Virginia may result in significantly higher or lower compliance costs for the	Support for the proposal is appreciated, as is the commenter's discussion of the benefits of RGGI and its market mechanisms. As discussed in the response to comment 37, a cap of 28 million tons was selected.

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	overall program. In RGGI's most recent auction, CO_2 allowances sold at a relatively weak clearing price of $3.79. This suggests that a too-high base budget could further weaken the carbon price signal. At this price, the societal value of the RGGI program is largely limited to income it generates for the participating states; it is too low to impact power system dispatch to any meaningful degree. Thus, Calpine recommends that Virginia set its initial base budget to no more than 34 million tons of CO_2. The proposed budgets account for recent trends in Virginia's electric generation sector, including planned retirements of fossil fuel generators and opportunities for clean energy and energy efficiency. The opportunity to trade with other RGGI states, and the inclusion of the CCR, help ensure that a base budget no higher than Virginia's proposed levels is reasonable and will ensure sufficient overall market liquidity. Recognizing the historically low allowance prices in the RGGI region, Calpine supports the proposal to include the ECR.	
88. Covanta	We fully support efforts to reduce GHG emissions through a market-based mechanism. We are proud to be part of efforts already underway to reduce GHG emissions in Virginia. Covanta operates EfW facilities in Fairfax County and Alexandria. These facilities are recognized internationally as a source of GHG emissions mitigation and low carbon energy generation. EPA has determined that EfW facilities reduce lifecycle GHG emissions by one ton of CO_2 equivalents (CO_2e) for every ton of MSW diverted from a landfill and processed. Based on Virginia data, every ton of MSW diverted to EfWs reduces GHG emissions by roughly 0.7 tons CO_2e. Covanta's Alexandria and Fairfax facilities annually reduce GHG emissions by over 900,000 tons of CO_2e a year relative to landfilling. Capping emissions through a trading-ready approach will incentivize the use of low-carbon energy sources that promote economic development and job creation. To achieve the most cost-effective program, we support a full portfolio of clean energy technologies and services, including wind, solar, energy efficiency, and EfW. We encourage DEQ and DMME to leverage the set-aside mechanism to further support renewable generation, both for existing facilities that face ongoing operating costs as well as new capacity, inclusive of both greenfield development and additional generation achieved at existing facilities. We also support the proposal to allocate allowances on the basis of regularly updated electricity output, as opposed to historical emissions. This approach provides the greatest alignment between the carbon intensity of electrical generation and the market-based policy signal.	Support for the proposal is appreciated. DEQ agrees that EfW facilities play an important role in the reduction of carbon pollution.
89. Center for Resource Solutions	The RGGI Model Rule includes a voluntary renewable energy market set-aside provision. Virginia would be able to draw on the experiences of 8 other RGGI states	As discussed in the response to comment 51, DEQ recognizes the value

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(CRS)	that have successfully implemented this provision. We strongly recommend that Virginia incorporate this or a similar provision in order to maintain and grow the environmental and economic benefits of voluntary, private investment in renewable energy. Under the rule, GHG reductions at regulated electricity generating facilities due to renewable energy generation will be automatically counted and reported by those facilities toward compliance, and since the rule determines and fixes the level of emissions from the sector, there is no net change to emissions at regulated sources due to renewable generation. In this scenario, voluntary renewable energy can have no impact on statewide or regional GHG emissions beyond what is already required; furthermore, it subsidizes compliance for regulated entities. As voluntary renewable energy reduces emissions counted toward compliance, voluntary purchases help reduce the cost of compliance, making it cheaper and easier for regulated emitting facilities to comply. This presents a different value proposition for voluntary and corporate buyers and investors in comparison to circumstances prior to implementation of the rule. Voluntary renewable energy is not used to meet governmental targets or mandates--it stands apart from and builds on compliance efforts. This separation enables the voluntary market to make an incremental difference or "regulatory surplus." Voluntary purchasers of renewable energy tend to value this incremental impact highly. Renewable energy generation that is counted toward regulatory compliance cannot be considered surplus to regulation. Regulatory surplus with respect to GHG regulation may be important for voluntary renewable energy demand. Since many of the companies and individuals purchasing in the voluntary market do so a commitment to address GHG, an effect on emissions beyond what is required by law may be a non-financial benefit. Where renewable energy sold into the market does not have an effect beyond compliance and only helps regulated entities comply, this changes the effectiveness of voluntary renewable energy as a climate change solution for companies and individuals. As such, voluntary demand for renewable energy may decline if these benefits do not remain intact. Virginia's program can protect voluntary renewable energy benefits and demand by incorporating a provision that sets aside and periodically retires allowances for voluntary renewable energy, effectively lowering the emissions cap on its behalf. This mechanism would counteract the automatic counting of emissions reductions associated with voluntary renewable energy and recognize those emissions reductions as	of a voluntary renewable energy market as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement that set-aside. DMME may, at the appropriate time and in accordance with its regulations and policies select a voluntary renewable energy market set-aside.

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	incremental to what would otherwise be achieved through GHG regulations. This helps preserve voluntary demand and private investment in renewable energy as drivers of emissions reductions, which can lower the cost of and reduce the need for GHG regulations. The RGGI Model Rule contains provisions for the number of tons that would be allocated to the voluntary renewable energy market set-aside account in a specific control period, including a sample formula with which the state could calculate the quantity of set-aside allowances that would be required. Regulatory surplus is critical to sustaining clear voluntary claims and has been helpful in the RGGI region in sustaining voluntary investment in renewable energy beyond what is required. A voluntary renewable set-aside preserves regulatory surplus for voluntary renewable energy by lowering the emissions cap and recognizing those emissions reductions as incremental to what would otherwise be achieved due to the cap. A set-aside can motivate private capital to produce voluntary renewable energy generation and emissions reductions in excess of state mandates. Alternatively, where voluntary demand for renewable energy is limited, so is the development of renewable energy and associated emissions reductions. By not including a set-aside for voluntary renewable energy in the regulation, Virginia may potentially leave privately-funded emissions reductions on the table, which it will later have to regulate to achieve. Green-e sets the standard for the voluntary market . To maintain the impact of the voluntary market and meet consumer expectations, Green-e requires a set-aside mechanism or allowance procurement and retirement for certified sales in regions covered by cap-and-trade regulation. Due to lack of a set-aside, Green-e would not be able to certify voluntary sales of renewable energy from within RGGI or Virginia to customers in Virginia, unless the customer pays the additional price to independently purchase and retire an allowance. Since customers are unlikely to pay this additional cost, we anticipate that there would be no Green-e market for Virginia renewable energy generation, or for RGGI renewable energy generation that is sold into Virginia. Voluntary buyers in Virginia will have to get their certified renewable energy from outside of the RGGI region. In 2016, Green-e certified over 728,000 MWh in sales to over 30,000 retail customers located in Virginia. This shows strong demand for voluntary renewable energy in the state.	
90. Dominion Energy	We support a program that would allow for emissions trading and be trading-ready. The program should reduce carbon emissions not only in Virginia, but regionally. The program should encourage the growth of	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed

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	cleaner-emitting generation commensurate with the Grid Transformation and Security Act of 2018, which finds 5,500 MW of new solar and wind in Virginia in the public interest, as opposed to encouraging the increase in the dispatch of higher emitting generation in neighboring states. It must recognize the benefit of reducing purchased power from out of state and its impact on the environment, the Virginia economy and Virginia jobs. The program must establish a representative baseline that accounts for the emissions serving Virginia customer energy needs from which to determine and measure emissions reduction goals. This should account for emissions from in state generation sources as well as emissions from purchased power. The plan should evaluate and set emission goals and realistic implementation timelines that will provide needed time for the ramp-up of new renewables, energy efficiency programs, and infrastructure improvements in order to maintain the state's fuel diversity and goal to become more energy independent. The program should recognize the role of extending the operation of Virginia's existing fleet of carbon-free nuclear generation and the role of natural gas as the lowest cost, cleanest and most reliable form of dispatchable generation to complement the integration of renewables to the grid. It should also account for electrification of other sectors of the economy, such as transportation, and must not hinder the growth of electric vehicles. The program should be flexible, with multi-year emission averaging and other measures so that reductions can be achieved in the most cost-effective manner. The program should address electric system reliability and rate impacts.	in further detail below.
91. Dominion Energy	Any program setting carbon emission targets for electric generating units must accommodate for the dynamics of power generated outside of and imported into Virginia. The baseline and targets must account for the fact that Virginia is a net importer of energy from more carbon-intensive out-of-state resources. The program must also incentivize the expansion of lower-emitting cleaner generation in the state, and reduce imports of electricity. Encouraging the expansion of natural gas-fired combined cycle and renewable energy resources will grow the economy and lower emissions by decreasing reliance on imported carbon-intensive power. Setting a stringent cap on already cleaner generation in Virginia absent a similar level of reductions from neighboring states or a way to address leakage would increase the cost burden to Virginia generators. This would encourage lower cost electricity imports that are more carbon-intensive and not subject to a carbon cost adder, and result in limiting the dispatch natural gas combined cycle facilities in Virginia. In the PJM Interconnect, units are dispatched based on "replacement cost" of the variable components required	In theory, emissions "leakage" occurs when an emissions cap causes generation to shift from the area under an emissions cap to an area outside the cap, and that shift leads to increase in emissions. A number of factors make emissions leakage unlikely in the case of the trading program in Virginia. The electricity markets are in a period of significant change. Retirements of older plants and construction of new plants in new locations means changes in where power is generated. In addition, plants closer to the well heads tend to enjoy lower

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	to run the unit. The variable components include fuel and emission allowances, such as RGGI allowances. The replacement cost changes based on the market value of the type of fuel used in a unit and the market value of the allowance. Dominion does not choose when to operate its units, units are called upon by PJM. If Dominion units are above the target price for the day, other units, generally less controlled and more carbon intensive, will be called upon to meet load demand. Due to a carbon cost adder to the unit bid price when Virginia units bid into the electric market that other PJM resources would not have to account for, Virginia generators will be less competitive, resulting in increased imports. Coupled with the retirement or curtailment of fossil fuel-fired resources, this raises reliability concerns. These concerns are borne out by modeling analyses. In support of the company's 2018 IRP, ICF provided Dominion with forecasts for cases where Virginia joins/does not join RGGI. Virginia linking to RGGI does not reduce emissions regionally. The modeling results indicate that Virginia entering RGGI in 2020 does not result in overall carbon emission reductions in the EI or PJM regions by 2030. Emissions in the entire EI in 2030 are about 10 million tons higher than emissions in 2020 and about 3 million tons higher in the PJM region during the same period. The analysis shows that emissions reductions achieved in the RGGI region are offset by emissions increases in the non-RGGI portions of the EI region. Cumulatively, over 2020-30, emissions in the portion of the EI subject to RGGI are reduced by about 75 million tons, but increase by almost 90 million tons in the non-RGGI portion of the EI In the RGGI region, emission decreases over the period 2020-30 with Virginia linked to RGGI are driven by emission reductions in Virginia emissions in the non-Virginia portion of RGGI actually increase. The modeling results also show significant increases in net energy imports in Virginia, increasing from about 28% under the case with no carbon regulations in Virginia to 48% for the case with Virginia linked to RGGI. At the same time, the weighted average capacity factor for NGCC facilities in Virginia is projected to decrease by almost 50% between 2020 and 2030 under the RGGI case. DEQ modeling of Virginia linking with RGGI showed similar increases in power imports under both policy scenarios evaluated relative to the case with no carbon regulations in Virginia. DEQ has proposed an updating output-based allowance allocation approach that it believes will incentivize utilization of NGCC resources as a means to counter leakage. However, while an updating output-based allocation approach may be more favorable to NGCC units relative to coal-fired units, it does not address leakage. Natural gas-fired units in Virginia will still be subject to a CO_2 cost adder that	fuel costs—the primary operating cost for natural gas power plants. The cost of transmission, in contrast, favors plants that are closer to the load the plant serves. Thus, while differences in environmental costs have the potential to change the relative costs of plants in Virginia compared to plants outside Virginia, shifts in generation are determined by a whole host of other factors that are more significant than the low RGGI allowance price. Second, the owners of generation in Virginia are unlikely to face any competitive disadvantage relative to plants outside the state because the allowances are to be allocated to compliance entities under the program, and the amount of the allocations are to be determined on an updating output basis. To the extent a generator must use an allowance to generate power and also receives an allowance at no cost, the generator does not have an increased operating cost relative to plants outside Virginia. If there is no competitive disadvantage, there can be no shift in generation caused by the program. Third, vertically integrated utilities have the option of self-scheduling their generation in the competitive wholesale electricity markets. This means that even where generators outside the state have a lower operating cost that is the result of the program’s

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	units outside of the region will not be subject to. The effect of RGGI-equivalent reduction requirements in Virginia is likely to limit the dispatch of highly efficient and lower emitting NGCC facilities in Virginia and encourage the dispatch of higher emitting resources and increased emissions in neighboring states outside of the RGGI region. Average carbon intensity in 2030 of electricity serving Virginia with the state not joining RGGI is projected to be 742 lb/MWh in 2030; the carbon intensity increases to 784 lb/MWh if Virginia joins RGGI. This is a 5.7% increase in carbon intensity of the electricity used by Virginia customers largely due to increased electricity imports into Virginia, which have a higher carbon intensity than in-state generation.	allowance cost, utilities may choose to run anyway because it makes economic sense to do so. Utilities, therefore, have a tool to prevent the generation shifts that might otherwise constitute leakage. Fourth, updating output-based allocation is expected to encourage generation in the state, rather than discourage it. Because power plants receive allowances only when they operate, the program is set up to discourage generation shifts by rewarding in-state generation. According to an August 2017 study conducted by researchers at the Regional Economic Studies Institute and Resources for the Future, updating, output-based allocation can be an effective tool to counter incentives to shift generation to areas not covered by an emissions cap. Fifth, if a shift in generation does in fact occur there is some question whether the shift is likely to lead to an increase in emissions. Natural gas has become the dominant fuel in PJM and typically fuels the marginal unit. To the extent a shift occurs between a natural gas plant in Virginia to a natural gas plant outside Virginia, there may be no increase in emissions that occurs as a result of the shift, especially to the extent adjustments to the emissions cap are made over time to address any excess allocations

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		under the trading program. For all of these reasons, DEQ believes that emissions leakage is unlikely to occur under the program (see responses to comments 108, 136 and 144). Also note that the implementation of the DMME set-aside will also encourage the reduction of in-state demand, thereby reducing carbon pollution and further preventing leakage. To the extent the possibility of leakage may theoretically exist, current evidence suggest that it has not happened under RGGI. RGGI issued the "CO_2 Emissions from Electric Generation and Imports in the Regional Greenhouse Gas Initiative: 2015 Monitoring Report." This report, the seventh in a series of annual monitoring reports, summarizes data from 2005-15 for electricity generation, net electricity imports, and related CO_2 emissions for the participating states. These monitoring reports were called for in the 2005 RGGI MOU in response to concerns about the potential for the RGGI trading program to cause emissions leakage. The observed trends in electricity demand, generation, and net imports show there has been a small change in CO_2 emissions from total non-RGGI electric generation serving load in the RGGI region during 2013-15 when compared to the base period, and the CO_2

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		emissions from this category for 2015 show there has been virtually no change when compared to the base period. In other words, the carbon intensity of additional generation is reduced, and emissions leakage has not actually occurred. Linking to RGGI will make Virginia a participant in RGGI's scheduled program reviews, and those program reviews can address any leakage problems should they arise with the program in the future. RGGI participating states perform comprehensive, periodic program reviews to consider program successes, impacts, and design elements. Stakeholder meetings are held throughout the program review process in order to encourage stakeholder engagement and the submission of comments from interested parties. As part of this process, DEQ will evaluate how the program is working from a Virginia standpoint as well as in the context of the other RGGI states. In addition to regular RGGI program reviews, the regulation will also be subject to state periodic review as required by § 2.2-4017 of the Virginia Administrative Process Act. The periodic review procedure includes a review by the Attorney General to ensure statutory authority for the regulation, and a determination by the Governor whether the regulation is necessary for

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		the protection of public health, safety and welfare, and is clearly written and easily understandable. Regulations under periodic review are subject to public comment; this would be another venue to identify concerns about program implementation.
92. Dominion Energy	Based on ICF modeling, linking to RGGI is projected to cost Virginia customers about $530 million over 2020-30, significantly less than actually joining RGGI. The modeling indicates that Virginia linking to RGGI will lower allowance prices thereby lowering the cost of carbon compliance in other RGGI states, subsidized, in part, by Virginia electricity customers. Should Virginia link to RGGI, customers in RGGI states outside of Virginia will incur $876 million less in cost related to RGGI allowance purchases from 2020-30 than the RGGI states would incur without Virginia joining RGGI. Additional costs related to carbon reductions isolated to the state and stranded investments for forced closures will be borne by customers. With the majority of the PJM region not subject to carbon regulations, the energy market will favor non-Virginia generating units, making Virginia units less competitive. This will advantage licensed competitive service providers (CSPs) that cover load through power purchases from non-Virginia-based resources. Unless these costs are non-bypassable, larger energy customers that have the ability under retail choice to purchase energy from a licensed CSP may find that CSPs can provide more attractive pricing and can avoid the costs related to carbon reductions. To the extent larger customers migrate to CSPs, remaining customers will bear the cost for compliance with the state carbon program.	The commenter is correct that the modeling showed that linking Virginia's program to RGGI did modestly reduce the modeled allowance prices for the program overall. These lower costs are exactly what one might expect when making an emissions trading market bigger. Bigger markets open up greater opportunities for lower cost reductions and lower overall costs for consumers across the entire footprint, including in Virginia. The commenter provides no evidence to support its assumption that the PJM market will favor non-Virginia units over Virginia units in the presence of the program. In general, generating units place bids to supply power to the wholesale market and those bids depend on the generator's costs to generate power. Fuel cost is the biggest component of a bid to supply power, and fuel cost depends on the fuel market and a plant's efficiency, not on the program. The program will allocate allowances on the basis of output from a generating unit and allocations will be periodically updated. As a result, the program will provide additional value to

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		a generating unit in Virginia that operates. This will tend to encourage Virginia units to operate, not discourage them compared to units outside the Commonwealth that do not earn this additional value. In addition, to the extent a unit incurs an incremental cost from the program, that cost is expected to be offset in whole or in part by the allowance value received through the allocation and the consignment auction. Essentially, the outcome is an effective program with a modest price tag
93. Dominion Energy	The 33 million ton cap case uses assumptions from Dominion's 2017 IRP; the 34 million ton cap is based on RGGI assumptions. IRPs depict a suggested portfolio expansion and tend to change on an annual basis. While IRPs may provide guidance in setting long-term goals, their purpose is not to establish regulatory requirements. Fundamentals-based models, such as the IPM model, are useful for evaluating the impacts of policy strategies but should not be used to set the program baseline. Rather, an emissions baseline should be established on historic emission levels including allowance for historic variations in emission levels due to year-to-year differences in weather and fuel prices. For example, for the initial RGGI cap determination in 2005, RGGI designers set the 2009 cap about 4% above the average emission levels observed between 2000-02. Historical data have also been used by EPA in establishing baseline levels for various trading programs including CSAPR and the NO_X SIP Call. 2016 emissions for Virginia units that would be covered under the Virginia proposal were about 35.3 million tons. An analysis of statewide emissions from electric generating units in Virginia over the last 20 years shows an average annual emission level of about 35 million tons with ±1 0% CO_2 emission volatility. Average emissions over 2014-16 were about 34.3 million tons. Applying a 10% margin to account for variability would yield a cap of over 37.5 million tons. Applying the same 4% margin used in setting the initial RGGI cap yields a baseline of about 35.7 tons. Accordingly, the 2020 baseline should be between 35.7-37.5 million tons to provide a margin to account for year-to-year fluctuations in weather and fuel price volatility. (This analysis does not include emissions from new generation projects.)	As discussed in the response to comment 37, a base cap of 28 million tons was chosen as the most representative and effective starting point for the program. This number is a reasonable starting point as evidenced by the modeling results, which tend to show reasonable cost impacts from the program using this base cap number. As discussed in numerous comments elsewhere, energy efficiency and renewable energy are increasing in Virginia, and the cap-and-trade program will contribute to this trend.

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	The modeling performed for DEQ by ICF projects almost 1100 MW of additional coal-fired capacity retirements by 2020 in the Virginia assumptions case and over 1500 MW of coal capacity retirements by 2020 in the RGGI case. Unit retirements should not be used to set the baseline. Efforts to reduce emissions by way of unit retirements implemented in advance of the baseline date should be applicable toward compliance and not penalized by applying them toward a further reduction to the baseline level. The data record must include the emissions from all units covered under the program, including units at which CO_2 emissions are not measured by continuous emissions monitoring systems. Coupled with the ability to credit reductions that occur prior to 2020, this would be a more fair approach. The 2020 baseline and reduction targets thereafter should not be based on a presumption that energy efficiency potential based on policies in neighboring states can be achieved in Virginia. Dominion continually works to achieve operating efficiencies to obtain more output with fewer emissions. In addition, we offer a number of end-use energy savings programs to our customers. As reported in the 2017 IRP, these programs have already achieved a substantial amount of energy savings; however, some of these programs are due to expire. Implementation of future programs is subject to approval by the SCC, which is not within the company's control. Dominion has filed approximately 36 replacement and new programs for approval by the SCC, and to date about two-thirds of them have been approved. While there remains potential for energy savings from consumer-side energy efficiency programs, this expansion is subject to state law and regulation. The success of these programs is affected by the degree to which customers choose to participate. Regardless of the success of energy efficiency programs, utilities must be prepared to serve their native load. Accordingly, the emissions target should be based on reasonable expectations of achievable energy savings and the compliance timelines must provide adequate time for the development of energy efficiency programs deemed necessary to achieve such objectives. The Virginia cap should not be more stringent than levels that would have been imposed under the CPP. Although the intent of the Governor's directive is to regulate carbon in the absence of federal action, it does not compel the state to establish emission targets equivalent to or below levels that would have been imposed under the CPP, which was approximately 27.8 million tons in 2030. The mass-based carbon emissions target EPA established under the CPP underestimated potential	

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	future growth to meet energy demand and was the most costly compliance alternative identified in the 2017 IRP. The limits required under the CPP envisioned a nationwide emissions trading program. Virginia should not impose more stringent emission reduction requirements to address a global environmental issue while the states we compete with economically have no emission reduction goals or requirements. RGGI re-assesses its program every 4 years based on historical performance. Since 2009, RGGI has conducted program reviews in 2012 and 2016-17. Both reviews resulted in a lowering of going-forward CO_2 emission caps for the RGGI region. The next assessment period is scheduled to occur in 2021, which is only one year after Virginia would begin its participation in RGGI. This means that Virginia cap identified through 2030 may be re-negotiated in 2021 with other member RGGI states and may be different than what is currently proposed. Virginia's entrance into RGGI creates just two years (2020 and 2021) of "certain" CO_2 limitations. Based on RGGI's two prior re-assessments, the CO_2 cap will likely be different than what is currently proposed, which increases uncertainty in electric utility planning.	
94. Dominion Energy	We support limiting compliance applicability only to fossil fuel-fired electric generating units greater than or equal to 25 MW. Small combustion turbines and boilers below this threshold should not be subject. This is consistent with many existing federal and state-level EGU-based emission reduction programs including EPA's Acid Rain Program, CSAPR, and MATS, and the RGGI model rule. Consistent with the CPP, we support exempting units that use biomass as their primary fuel. In 2013, Dominion converted 3, 51 MW coal-fired units to 100% biomass. Close proximity to an ample supply of waste wood biomass as well as EPA's carbon-neutral policy for permitting were key economic drivers for these projects. Given Dominion's investment in renewable biomass, it is important that biomass emissions remain exempt. Any departure from EPA's prior treatment of biomass as carbon neutral or action that eliminates the use of this fuel as a creditable compliance option could raise compliance costs. This compliance exemption should also apply to fossil fuel-fired units that are co-fired with biomass, such as the Virginia City Hybrid Energy Center (VCHEC). Under the proposal, a fossil fuel-fired unit that co-fires with biomass would be obligated to hold allowances for all of its emissions. This is a disincentive for a coal-fired power plant to reduce its carbon emissions. VCHEC burns waste coal and co-fires with biomass. In 2008, the board directed DEQ to incorporate a timetable for biomass utilization in the facility's PSD permit. According to DEQ,	See the response to comment 67 for a discussion of biomass applicability.

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	the board chose this approach "in order to promote further reductions in sulfur dioxide emissions and show a reduction in carbon emissions. since biomass is considered a biogenic carbon-neutral material." Requiring VCHEC to now hold allowances under a state carbon program for emissions resulting from the burning biomass in compliance with an air permit provision established to address carbon is counterintuitive. Requiring fossil units that co-fire with biomass to hold allowances would also be inconsistent with RGGI which only regulates fossil fuel fired units and provides calculations to subtract CO_2 emissions from biomass from multi-fuel fired units. To regulate biogenic emissions would be a significant departure from the existing RGGI program. It would put Virginia's forest owners and biomass-related renewable energy investments at risk, while creating unnecessary complexity. To the extent that the regulation requires biomass units to hold allowances, the budget must be increased accordingly to assure that the emissions from these facilities are included in the baseline.	
95. Dominion Energy	Dominion supports the consignment auction approach but the proposal does not provide details of the auction process and how revenue will be handled and transferred. The rule mentions that such revenue transfers will be done "in accordance with procedures established by the department." Clarity is needed as to how the Virginia allowances, which are proposed to be allocated annually, will be merged with the RGGI auctions, which are conducted quarterly. Additional legislation is required for the board to designate use of revenue associated with a trading program. Absent such authority, DEQ could not directly conduct an allowance auction or collect revenue from an auction. The consignment auction approach could provide a mechanism for the rule to proceed. Accordingly, to the extent the regulation links to RGGI via auction, we support the consignment approach. Direct auctioning would increase the stringency and cost of the program by forcing generators to purchase allowances they otherwise would have been allocated. EGUs would have to pay twice to reduce emissions: first to reduce emissions from affected EGUs or to develop new low-emitting generation, and second to obtain allowances to cover their remaining emissions. Modeling scenarios performed by ICF with Virginia joining RGGI with the auction proceeds returned to the state projected costs to the customer that are three times higher than costs estimated under the consignment auction approach. We support the proposal to allocate most allowances to affected EGUs using either historic generation (output based) or emissions data. This approach is reasonable,	DEQ agrees with the commenter that at this time the consignment auction is a cost-effective approach for the trading program. Use of the RGGI auction platform provides an already functioning system with detailed procedures that have proven effective. Details as to how the specifics of the auction will operate will be addressed in auction "instructions" which are developed separately from the regulation. DEQ will take the commenter's concerns into account when those instructions are developed. The consignment auction is designed to be cost neutral while enabling participation in the RGGI auction and providing for implementation of the CCR, ECR, and auction reserve price. Generally, the purpose of a regulation is to establish the relationship between DEQ and an affected facility; i.e., the department sets requirements that the

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	consistent with many of EPA's other emissions trading programs, such as the ARP and the CSAPR, and will help to minimize compliance and customer costs. Allocating allowances directly to affected EGUs who have a clear financial interest in complying with the rule will create a more reliable, predictable, and manageable system. Direct allocations to non-affected entities could increase the stringency of the cap by forcing affected sources to acquire allowances they otherwise would have been allocated, and under the proposed consignment auction approach, would have the opportunity to recover cost through auction revenue returned to the generator. This would increase the cost of compliance for affected EGUs and therefore ratepayers. RGGI's quarterly auctions limit how many allowances a single entity can bid (25% of the initial offering of CO_2 allowances in the auction). If Virginia participates in the RGGI auction program, such a limitation might not make it possible for all the compliance entities in the program to rely strictly on the auction to acquire their necessary allowances and they may be forced to go to the secondary market to get sufficient allowances needed to comply. This bidding limitation has not been an issue to date in RGGI because there has not been a single entity requiring enough allowances to hit the 25% limit. Virginia should advocate that RGGI amend this rule by expanding the size of the bid limitation by anyone entity such that every entity has the possibility of relying on the auction for compliance.	facility must meet, and the facility does so following the provisions of the regulation.
96. Dominion Energy	An updating frequency of less than 3 years (including annually) should not be considered. A unit that retires should not be required to give back allowances it has already been allocated. The allocation approach should provide a reasonable lag time between unit retirements and the discontinued allocation of allowances to those units, an approach EPA has allowed under trading programs such as CSAPR. The updating allocation methodology will effectively transition retired units out of the allocation cycle without requiring units to give back allowances. With respect to the baseline for determining a unit's pro-rata share of the state total budget, we suggest using the average of the 3 highest years over the previous 5-year period. This approach, which is consistent with other successful programs such as CSAPR, would provide additional flexibility to assure a baseline representative of a unit's normal operations and filter out years when a unit experienced atypical utilization. The rule must provide a mechanism for providing allocations to units that meet the definition of an existing unit but do not have 3 years of historical operational data. In cases where a unit does not have a full year of operational data over the 2016-18 time period, the allocation could be based on an estimate of	A 3-year period was chosen as the most realistic compromise between too much and too little flexibility. It is designed to avoid year-to-year variations that result from external factors that may influence operation and have a serious impact on allocations. At the same time, the 3-year period prevents allocations from being coming static.

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	projected annual operation with a requirement that the source give back any unused allowances for redistribution to existing sources.	
97. Dominion Energy	Under the proposal, 5% of the statewide budget would be set aside and allocated to DMME. These allowances would be consigned for auction by the holder of a public contract with DMME to assist the department in the abatement and control of air pollution. However, the proposal provides no details as to how the revenues obtained from the sale of these allowances in the RGGI auction would be used. The allowances and proceeds allocated to DMME to administer the program are revenues of the state and cannot be paid to DMME but rather would have to go into the State Treasury. DMME would only be allowed to use funds appropriated by the General Assembly to cover administrative and other costs. Although not explicitly stated, DEQ has indicated its intent to at least in part direct the 5% set-aside to encourage energy efficiency projects. To the extent the set aside is directed toward incentivizing energy efficiency, both demand- and supply-side energy efficiency improvement programs, including voltage optimization and other transmission and distribution efficiency improvements, should be eligible. Eligibility should include programs that help reduce carbon emissions such as infrastructure for electric vehicles.	As discussed elsewhere, DMME will determine how the set-aside is implemented, whether through incentivizing energy efficiency, other transmission and distribution efficiency improvements, or something else. DEQ agrees that both demand- and supply-side energy efficiency improvement programs should be eligible.
98. Dominion Energy	DEQ must explain adjusting the Virginia emission cap on the basis of banked allowances amassed over 2018-20 by affected entities in other RGGI states that Virginia affected sources will not be holding since Virginia entities will not become subject to an emissions cap or required to hold allowances until 2020. RGGI states were not subject to such adjustments through the first two 3-year compliance periods. Banking should be unlimited. Provisions to adjust emissions caps or withhold allowances based on volume of banked allowances should be delayed to provide time for the Virginia carbon market to mature. Similarly, there is no justification for applying the ECR mechanism at the inception of the Virginia program. Virginia sources will not be carrying any banked allowances during the initial compliance period. Under the RGGI model rule, states have discretion whether to implement the ECR mechanism; New Hampshire and Maine do not intend to implement this mechanism. Accordingly, DEQ should allow the Virginia market to mature before applying any mechanism that would artificially reduce the emission cap and increase compliance costs by driving up the allowance price. Another concern with adjustment mechanisms is that compliance entities will be compelled to purchase allowances from noncompliance entities to obtain enough allowances to comply with reducing caps. This	DEQ has developed the rule with the intent of linking to RGGI, because linking to a larger, well-functioning, existing program is a reasonable, efficient way to reduce emissions from Virginia units at the lowest cost. In establishing the provisions of the program and analyzing its potential impacts, DEQ has taken into account the provisions in the rule, including the adjustment of the allowance budget over the course of the program, and implementation of the ECR. Both of these features were included in the modeling and analysis conducted for the program and that analysis showed the program can be implemented yielding substantial benefits at a modest cost.

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	will be further complicated by the ECR that will reduce the bank of allowances. It is likely that the cost of allowances will increase as noncompliant entities seek a return on their investments, which increases compliance costs. The adjustment provisions should not be incorporated into the Virginia program without further evaluation. Applying adjustments and restrictions to the unlimited use of allowance banking would complicate and limit the very emissions trading system that the RGGI states have praised for its success.	The bank adjustment, CCR and ECR are all required elements for participating in the RGGI program. The ECR will only be triggered if the allowance prices are lower than expected and only to the extent the winning bids at a particular auction are lower than the ECR trigger price. The ECR mechanism is designed, therefore, to operate only in those circumstances where allowance prices are below the ECR trigger price.
99. Dominion Energy	The RGGI program has always allowed for a multi-year compliance true-up timeline. For the first 6 years of the program, affected entities were required to demonstrate compliance on a 3-year cycle. Beginning in 2015, the program was modified to a tiered 3-year compliance obligation. This compliance obligation will be maintained under the revised RGGI program and model rule that takes effect beginning in 2021. This allows for a smooth transition for RGGI compliance entities into the next phase of the RGGI program with a new 3-year compliance true-up (2021-23) following the last 3-year compliance true-up (2018-20) under the current phase. DEQ proposes to implement a similar tiered 3-year compliance approach. We generally support a multi-year compliance approach as it affords compliance entities flexibility in meeting compliance obligations. Note that the CPP also allowed for a 3-year compliance true-up. Aligning true-up requirements with compatible 3-year compliance cycles in RGGI makes sense.	Support for the proposal is appreciated.
100. Dominion Energy	With the Virginia program starting in 2020, the regulation would impose a one-year initial compliance timeline (to address 2020 emissions) before converting to a 3-year compliance cycle. DEQ explains that initial 2020 allocations and a one-year compliance true-up obligation is needed to align the Virginia program with RGGI's current 3-year compliance cycle. This single year compliance requirement places a burden on Virginia generators that no other compliance entities in the RGGI program have. In order to address this issue, DEQ should defer the implementation of the Virginia carbon program until 2021. This would fully align the compliance obligations under the Virginia program with RGGI's current 3-year cycle and provide a smoother transition to linking with the RGGI allowance system.	DEQ acknowledges the commenter's concern. The department was faced with a choice: either abbreviate the normal 3-year compliance period to 1 year in order to align the program start with RGGI (2021), or delay implementation and enable sources to obtain a full 3-year compliance period. There are advantages and disadvantages to either approach. DEQ based its final decision on what would best meet the overall program goal of smoothly

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		linking to RGGI. Starting the program on time and limiting facilities to a 1-year compliance period does impose an immediate burden on sources; however, this will benefit them in the long run by giving them a longer term compliance period as well as a smooth transition to the RGGI program. Adjusting as the commenter recommends would provide relief in the short term but put facilities on a steeper, more rapid compliance period overall.
101. Dominion Energy	We support adoption of the CCR which would provide a pool of additional allowances for sale in the consignment auction if the costs of allowances exceed a certain threshold. Such a mechanism is needed to address unexpected scenarios and to address potential adverse impacts on electric system reliability, and could also offer affected entities protection in terms of not being penalized for fewer emission reductions resulting from the unpredictable performance of renewable generation units.	DEQ agrees with the commenter that the CCR is a needed mechanism; see comment 136 for more detail as to how the CCR works.
102. Dominion Energy	The regulation should include offsets as allowed under the RGGI model rule, expanded to allow offsets that will encourage the reduction of emissions from electrification of other sectors of the economy, such as transportation. EVs and charger installations should be allowed to generate offsets. In 2016, more carbon emissions came from the transportation sector than the power sector. The regulation should allow reductions in emissions from sulfur hexafluoride (SF_6), one of the most potent GHGs. This offset category was eliminated from the RGGI model rule on the basis that, to date, there had been no SF_6 projects finalized in any RGGI state. One of the reasons for this has been may be the overall low RGGI allowance prices coupled with an abundant supply of RGGI allowances rendering administration costs undesirable. However, the more stringent RGGI cap and new mechanisms designed to minimize the allowance bank and drive the allowance price higher may now make these projects more viable.	As discussed in the response to comment 26, offsets are not being included in the regulation at this time. DEQ agrees that control of carbon pollution from the transportation sector is important, and may be addressed in another action.
103. Dominion Energy	Table 140-5A in 9VAC5-140-6210 D 2 and Table 140-5B in 9VAC5-140-6210 E 2 should be corrected to reflect that the annual number of CCR and ECR allowances listed are in million tons.	The proposal has been corrected accordingly.
104. DuPont	DuPont acquired the cogeneration units adjacent to its Spruance Plant as the supply contract expired and the previous owner discontinued operation. DuPont has a long-term agreement with Veolia to operate and maintain	DEQ agrees that the phrase "owned by an individual facility" should be removed; see the response

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	the cogeneration units that supply the Spruance powerhouse on the manufacturing campus. Veolia plans to upgrade the utilities to be more efficient, and enhance performance and reliability, which will help DuPont reduce its costs and environmental footprint. The unit that Veolia will operate and maintain for DuPont is a combined heat and power (CHP) unit. DEQ exempts certain industrial CHP units under 9VAC5-140-6060 B. However, this exemption requires that the CHP unit be owned by the industrial end user rather than a third party. DuPont has engaged Veolia to utilize their specialized expertise to operate and maintain the industrial utility, while allowing DuPont to focus on manufacturing. Rather than regulating CHP ownership, DuPont suggests that DEQ remove the phrase "owned by an individual facility and" so that 9VAC5-140-6040 B reads: "Exempt from the requirements of this regulation is any fossil fuel power generating unit located at that individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility."	to comment 65. Under the RGGI Model Rule, facilities that provide less than 10% of their power output to the grid are exempt from compliance obligations and the proposal has been revised accordingly. The regulation has been further amended in order to address CHPs with more clarity; see the response to comment 74.
105. Environmental Defense Fund (EDF)	EDF strongly supports regulations to limit carbon pollution from Virginia's power sector because Virginia has profound public health and climate benefits at stake. An overwhelming majority of Virginians agree: 87% support Virginia continuing to reduce carbon emissions from power plants. The board has clear existing authority to regulate carbon emission through a statewide cap, trading program, a revenue-neutral consignment auction, and linking with RGGI. EDF supports Virginia linking to RGGI and aligning its proposed rule accordingly. An expanded regional carbon trading market in which Virginia links with the existing RGGI program has a number of benefits, including greater liquidity, streamlined administration, and additional opportunities for cost-effective compliance. The benefits of cost-effective CO_2 emission reductions from a well-designed CO_2 trading program are clear. For example, from 2012-14, RGGI added $1.3 billion in economic value in the region and led to the creation of more than 14,000 jobs. By finalizing a strong CO_2 trading program that links with RGGI, Virginia is poised to garner significant economic, public health, and environmental benefits as well. Virginia has tremendous opportunity to accelerate clean energy deployment and expand the role of renewables and energy efficiency in the state. Virginia has an estimated 89,000 MW of onshore and offshore wind capacity potential that could serve an electric load that outstrips the state's own needs. Virginia can also take advantage of tremendous solar capacity potential. Shifts in Virginia's power sector reflect national trends toward low carbon electricity. In Virginia, power sector CO_2 emissions declined by 24% from 2005-15. These	Support for the proposal is appreciated.

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	reductions have been driven by falling costs of renewable energy, low natural gas prices, changing consumer preferences, and policies that incentivize clean energy deployment.	
106. EDF	Thirty million tons should constitute the upper bound for the starting budget in 2020, with strong evidence indicating an even lower budget. In addition, the budget should decline annually by a tonnage amount of at least 3% of the 2020 budget--which is in alignment with the existing RGGI program--and consider a more stringent rate of decline. Recognizing that the ability to accurately predict future emissions based on current data has limitations, EDF also recommends DEQ provide for a mechanism to adjust the base budget in 2020 or 2021 if actual emissions are lower than projected. The 2020 budget should be at or below emissions that would have occurred under a BAU scenario. This is crucial in order for the program to drive additional CO_2 reductions beyond BAU, as well as greater near-term emission reductions in the early years of the program, enabling more cost-effective reduction pathways and opening the door to achieving higher levels of mitigation over the long-term. A starting base budget can also be lower than expected emissions under BAU, since covered facilities will have time to plan ahead for compliance with the regulation--and in fact, have already had time to anticipate the general direction of the regulatory framework given the policy direction outlined in ED 11 and the ongoing rulemaking process. Cost-effective abatement opportunities in the power sector are readily available. Modeling suggests that Virginia power sector CO_2 emissions under BAU in 2020 could be as low as 24 million tons. In 2017, DEQ projected Virginia power sector emissions would be 33-34 million tons in 2020, using the Integrated Planning Model (IPM) and assumptions from Annual Energy Outlook (AEO) 2017, Dominion's 2017 IRP, and the RGGI 2016-2017 Program Review. The Natural Resources Defense Council (NRDC) in 2017 projected BAU emissions would be 32.8 million tons in 2020, using assumptions from AEO 2017. However, more recent NRDC modeling conducted in 2018 used updated assumptions to project BAU emissions of 28 million tons in 2020. Meanwhile, The Rhodium Group projected BAU emissions well below DEQ's forecast, as low as 24-25 million tons in 2020, with cumulative emissions of 247-277 tons of CO_2 in 2020-30. These additional modeling efforts suggest DEQ's original projections of 2020 BAU emissions are likely to be overestimates. As new data become available, projections of 2020 BAU emissions could be expected to decline further.	The 2020 budget reflects the reference case used to determine the proposed base budget, and was at or below emissions that would have occurred under a BAU scenario. As discussed in the response to comment 37, a cap of 28 million tons has been selected. Because of the importance of aligning the Virginia program as closely to RGGI's as possible, the cap and rate of decline must align. This will ensure that the program operates as effectively and efficiently as possible.

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	Recent announcements of fossil fuel deactivations, as well as new developments for renewable energy and energy efficiency, further indicate the power sector is becoming cleaner, and demonstrate a pace toward a lower-carbon electric sector in Virginia that is challenging for modeling efforts to fully capture. Clear trends toward a cleaner power sector in Virginia reflect an ongoing transformation toward a low-carbon future for the U.S. electric power sector. As of April 3, 2018, 1,721 MW of coal and natural gas generating capacity is now slated for deactivation by March 2019, according to PJM. In 2016, these units emitted 3.87 million tons of CO_2. In 2017, the units emitted 1.71 million tons. Meanwhile, recent developments suggest a promising future for zero-emitting solar and wind generation that could reduce Virginia emissions by displacing fossil fuel generation. As of April 2018, a total of 3,621 MW of solar capacity in the PJM interconnection queue is expected to enter into service by the end of 2019. The Virginia Solar Energy Development and Energy Storage Authority reported that as of November 2017, 2,703 MW of solar was under development in Virginia. In March 2018, new energy legislation in Virginia declared 5,000 MW of new solar capacity and 16 MW of offshore wind capacity to be "in the public interest." New energy legislation also paves the way for Virginia to deploy more cost-effective energy efficiency, which, by reducing demand for electricity, can contribute to avoiding CO_2 emissions. These trends combined with recent modeling indicates that 2020 BAU emissions are likely to be lower than initially estimated and could continue to decline between now and the beginning of the program. EDF recommends that DEQ set a base budget that starts no higher than 30 million tons in 2020, but encourages DEQ to consider evidence from recent modeling and power sector trends that supports the setting of a base budget that starts below this upper bound. A lower starting budget can also facilitate additional benefits that can result from a more environmentally protective program. A base budget that starts below 30 million tons would be consistent with a trajectory for Virginia to reach zero carbon emissions from the power sector by mid-century. A lower budget would also help drive additional near-term emission reductions, unlocking the benefits of taking earlier actions to mitigate climate change. With annual average temperatures in the U.S. having increased by approximately 1.0°C in the last 115 years, the impacts of climate change are already apparent. Increased magnitudes of temperature rise are likely to further increase the prevalence of harmful climate changes worldwide, including severe weather events, extreme temperatures, extreme precipitation changes, and impacts to natural ecosystems and human necessities such as food security. Given cost-effective	

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	opportunities to reduce carbon emissions in the electric sector, and the lower overall emissions that can result from securing power sector decarbonization in advance of other sectors switching to electricity, it makes sense that the electric power sector should do more than its proportional share in reducing emissions, and follow a steeper trajectory earlier in time. In order to assess whether Virginia's emissions budget is consistent with this trajectory, DEQ can evaluate historical emissions data from 2016 and 2017. Using this data as one set of possible benchmarks, a straight-line decline from 2016 or 2017 emissions to zero by 2050 is consistent with 2020 emissions of 29-30 million tons or less, supporting a base budget that starts below 30 million tons in 2020. The Fourth National Climate Assessment finds, "Net cumulative CO_2 emissions in the industrial era will largely determine long-term, global mean temperature change. A robust feature of model climate change simulations is a nearly linear relationship between cumulative CO_2 emissions and global mean temperature increases. … Increasing the probability that any given temperature goal will be reached therefore implies tighter constraints on cumulative CO_2 emissions. Relatedly, for any given cumulative CO_2 budget, higher emissions in the near term imply the need for steeper reductions in the long term." Furthermore, a number of studies find that the timing of efforts to reduce CO_2 emissions can significantly impact the economic and environmental costs of action. Delayed action requires significantly accelerated mitigation efforts in later years to achieve the same cumulative emissions goals. Studies show that delaying mitigation efforts can increase the economic costs of necessarily more ambitious mitigation in the future. Delayed action also increases the risk of overshooting cumulative emission targets. Conversely, prioritizing emission reductions today can enable long-term mitigation to be more cost-effective and increase the likelihood of keeping temperature increases below target limits. By setting a lower 2020 starting budget, Virginia can facilitate long-term economic and environmental benefits of prioritizing early emission reductions and further limit cumulative CO_2 emissions from the power sector. The RGGI states have determined a regional cap for 2021-30 that declines by 2.275 million tons per year after 2021--approximately 3% of the 2021 cap--resulting in a 30% reduction in the cap from 2020-30. Virginia should achieve at least a similar level of reductions as it contemplates linkage with RGGI. Furthermore, ED 11 directs DEQ to create a rule to reduce CO_2 from the power sector that provides for a "corresponding level of stringency" with CO_2 limits in other states. DEQ should also consider a steeper decline, considering the benefits	

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	of prioritizing near-term reductions and of maintaining consistency with a trajectory to zero emissions by midcentury, as discussed above. For example, a pathway to zero emissions by 2040 could imply a yearly decline equivalent to 5% of the 2020 budget, while a path to zero emissions by 2050 could imply a yearly decline equivalent to 3.3% of the 2020 budget. A steeper rate of decline at the program outset, even while retaining a lower rate of decline in later years, would also facilitate further limits on cumulative emission reductions and additional near-term reductions.	
107. EDF	EDF recommends a mechanism to adjust the emissions budget as new data and analysis emerge. An adjustment could be made to lower the emissions budget in order to achieve additional emission reductions if abatement opportunities are more readily achievable and cost-effective than forecasts show, as well as to optimize market function. DEQ could establish a mechanism to automatically adjust the budget if certain conditions are triggered, or provide for a manual adjustment early in the program. An automatic adjustment mechanism could use a pre-determined formula to tighten the emissions budget under certain conditions. DEQ could establish such a mechanism to adjust the base budget in early years of the program if actual emissions are lower than projected--not unlike how RGGI has adjusted its cap in the past to account for banked allowances. DEQ has a range of options for the timing of any such adjustment, and should consider factors such as the availability of new emissions data, ease of administration, and the timing of RGGI auctions, compliance periods, and the 2021 bank adjustment. Alternatively, DEQ could provide for a manual adjustment of the emissions budget when new data becomes available--for example, 2019 or 2020 actual emissions from the affected power sector units. Virginia has appropriately included the ECR and withholding of allowances in alignment with RGGI's Model Rule. DEQ should harmonize the minimum reserve price for the Virginia program with the minimum reserve price in RGGI. There is a continued need for emission reductions beyond 2030 to achieve climate goals and protect Virginians from the impacts of carbon pollution. DEQ should participate in RGGI program reviews. Periodic program reviews are an important means to assess program success and make changes to strengthen the program. It is important for DEQ to provide as much long-term certainty around carbon regulation as possible--market certainty will contribute to a successful emissions market, and can also help ensure Virginia is at the table as a leader on climate policy in the future.	As part of linking to RGGI, it will be essential for Virginia to participate in RGGI market controls--such as the CCR and ECR--and in periodic reviews to adjust the program as needed. There is no need for Virginia, at this point, to develop its own preemptive mechanisms. DEQ appreciates the need to respond quickly to unpredictable market fluctuations and other unknown issues; however, the best approach to do so is in concert with the other RGGI states. Should a definite state need arise, a Virginia-specific remedy may be implemented.
108. EDF	EDF supports allocating allowances to covered sources with an updating output-based approach, and consignment of allowances to the RGGI auction. This	The commenter's remarks on how the updating output-based approach and

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	design smooths integration with RGGI, facilitates transparency and market efficiencies, and mitigates leakage. Consignment auctions are a proven method to facilitate transparency and price discovery. Successful examples of consignment auctions include the federal Acid Rain SO_2 Trading Program and California's Cap-and-Trade Program. A consignment auction in Virginia should be able to integrate seamlessly with the RGGI auction and key design elements including the price floor and ECR. Consignment auctions can create further incentives to reduce electric sector carbon emissions through a carbon price signal reflected in electricity rates. Furthermore, measures can be taken to provide benefits to ratepayers alongside a carbon price signal. Analyses conducted by EDF and RFF in the context of the CPP found that an updating output-based approach can be an effective means of mitigating emissions leakage--wherein carbon emissions shift out-of-state or to sources not covered by the program through, e.g., shifting generation. Modeling conducted by RFF found that an updating approach to allocate 100% of allowances to a subset of eligible sources under the CPP (as opposed to a historic approach) could reduce leakage by up to 64% compared to a mechanism that allocated only 5% of allowances with an updating output-based approach. Similarly, EDF analysis found that allocating all or nearly all CO_2 allowances with an updating output-based approach could significantly reduce leakage. EDF encourages Virginia and other RGGI participating states to monitor and evaluate whether and to what extent emissions leakage might be occurring on an ongoing basis, and evaluate additional opportunities to effectively mitigate any leakage that may occur.	consignment of allowances to the RGGI auction will address leakage are acknowledged. DEQ agrees that these mechanisms, along with robust program reviews for which RGGI explicitly monitors leakage, will discourage and limit emissions leakage. See the discussions under the response to comment 91.
109. EDF	Industrial power plants over 25 MW in size are a source of carbon pollution that DEQ proposes to exempt. Much of the literature on carbon market designs suggests that broader inclusion of sources can lead to more cost-effective and efficient outcomes. Industrial power plant sources may be included in future climate policies and Virginia can help provide regulatory certainty to these facilities by bringing them into the program and drive investments to reduce emissions now. In order to meet our climate goals, more emitters will need to reduce emissions. There are extensive, cost-effective opportunities for improving efficiency and increasing renewable energy use across industrial sources and DEQ should include these sources in the program.	See the response to comment 65 for a discussion of how industrial facilities will be handled. DEQ agrees that energy efficiency and renewable energy are important elements in a carbon reduction program, and will likely continue to improve in Virginia for a variety of market- and pollution control-based reasons.
110. EDF	A strong trading program can provide important benefits for communities overburdened by pollution. Without affecting timely finalization of the rule, DEQ should conduct ongoing analysis and monitoring to ensure communities disproportionately impacted by air pollution benefit from efforts to abate carbon pollution. This	As discussed in the response to comment 55, the EO 73 EJAC Council will take the lead on directly addressing environmental justice issues. DEQ will

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	analysis could include a geospatial EJ screen using demographic and environmental indicators to identify disadvantaged communities. DEQ should continue to work with affected communities and other stakeholders, such as the EJAC, to identify instances of adverse economic or pollution impacts on disadvantaged communities and take appropriate action to mitigate the effects. DEQ should also continue to engage meaningfully with EJ stakeholders and disadvantaged communities as the agency works to finalize this rule and implement the program. EDF commends DEQ for its efforts to date to hold public hearings across Virginia and invite deep engagement from diverse stakeholders, and encourage DEQ to continue this practice.	continue its public outreach efforts in such a way as to maximize public participation from all Virginians.
111. Forest Products Industry National Labor Management Committee (LMC)	LMC opposes joining RGGI due to concerns it would increase electricity and natural gas prices for businesses and consumers. The following language should be included in the regulation: "Forest biomass, including forest products manufacturing residuals, should categorically be treated as carbon-neutral whether or not it is co-fired with fossil fuel." The carbon profile of biomass is not at all altered when co-fired with other fuels. The biomass portion of the fuel mix has the same characteristics no matter what fossil fuel it may be co-fired with. It is the characteristics of the biomass feedstock, not of the power generation process or facility, that support treatment of biomass as carbon neutral. Additionally, LMC strongly urges the regulation not be expanded beyond its focus on utilities to also apply to industrial boilers. ED 11 pertains exclusively to controlling CO_2 emissions from electric power facilities. The Economic Impact Assessment, the direction given to the Regulatory Advisory Panel, the emissions and economic modeling conducted by DEQ and its consultants, and DEQ's written and oral information supporting the proposal indicated that the regulation applied only to the electric power sector.	See the response to comments 65 and 67 for further information on rule applicability.
112. GRID Alternatives Mid-Atlantic	We understand the consignment is designed to be revenue neutral. However, DMME will have a contract with a third-party administrator that would sell allowances allocated to DMME and make the funding available for use in a variety of programs to help reduce CO_2 emissions. Accordingly, one of DMME's strategies is to accelerate the adoption of energy efficiency practices and expand the deployment of renewable energy. This funding could be utilized to create new economic opportunity in the state through solar energy. Solar provides long-term financial relief to families struggling with high and unpredictable energy costs, living wage employment opportunities in an industry adding jobs at a rate of 20% per year, and a source of clean, local energy sited in communities that have been disproportionately impacted by traditional power generation. Virginia solar jobs increased by 10% in 2017, and the state now has over 3500 solar workers. Virginia is poised to experience	DEQ recognizes the value of low-income solar programs as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement that set-aside. DMME may, at the appropriate time and in accordance with its regulations and policies, implement a low-income solar program set-aside. As

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	1.5% solar jobs growth in 2018. Low-income ratepayers pay a disproportionate amount of their income on utility bills. These customers stand to benefit most from solar energy, and must be prioritized through targeted policies and programs. The proposal assumes that all revenues raised from the auction by utilities are returned to ratepayers. In the case of distribution utilities dependent on other wholesalers for power, such as rural electric cooperatives and municipal electric entities, those wholesale contracts could impose costs on those dependent purchasers with no mechanism--and nothing that DEQ could make a requirement--for the wholesaler's auction revenues to offset those costs or return those revenues to the underlying load that is responsible for paying those costs. There may be solutions to this issue; however, those solutions would be outside DEQ's purview, either involving an order from the SCC, a mandate to run auction revenues through a FERC formulary rate in a certain way, or legislation. Low-income consumers that use electricity should not pay for the costs of carbon regulation without also receiving the benefit of revenue, if any, from allowance auction proceeds. The proposal does not fully address this issue. GRID Mid-Atlantic has seen the benefits of low-income solar programs in markets across the country. We recommend the regulation directly benefit low-income ratepayers with a solar program funded by DMME's allowance funding. A low-income solar program would have the goals of significantly reducing the electrical energy burden of Virginia's low-income ratepayers and training the next generation of solar workers. This type of programming would complement DMME's strategic objective to expand the deployment of renewable energy and overall reduction of CO_2 emissions.	discussed in the response to 55, affected communities will be monitored on an ongoing basis to assure that no disproportionate impacts are experienced. Note that the trading program as well as how the costs of energy in Virginia are arrived at are open and transparent. There will also be numerous opportunities to identify and remedy any identified impacts.
113. International Emissions Trading Association (IETA)	IETA welcomes this opportunity to voice strong support for the proposal. More than 50% of the world's economy is subject to some form of carbon pricing, most of which is under cap and trade systems. This growing coverage includes major international trade partners and the entire RGGI collaborative. Virginia's proposed program allows the use of market-based mechanisms and trading of CO_2 allowances. It provides an important link to RGGI's program, enabling Virginia market participants to have access to a bigger, more efficient market. 9VAC5-140 will allow Virginia to join the other RGGI states as a leader in cutting emissions that lead to climate change and air pollution, while providing opportunities for in-state clean economic growth and business development. The rule would also provide regulatory certainty to Virginia's electric generation sector, including a clear price signal and incentive for electricity generators to invest in innovative lower carbon technologies. IETA sees the	Support for the proposal is appreciated, as is the commenter's discussion of RGGI's attributes.

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	program having 4 fundamental advantages: flexibility, cost-effectiveness, linkability, and building on the proven success of emissions trading systems globally--and most importantly--in the context of the RGGI cap and trade program. The program accesses regional allowance auctions and gives participants across the RGGI region the opportunity to participate in the Virginia market. This will provide a broad market for program revenue, price discovery, and market liquidity. Issuing allowances to generators based on their current GHG emissions and allowing them to sell excess allowances creates an incentive for generators to be innovative in their carbon investment and compliance strategies. Compliance flexibility afforded by the program will ensure that emission reductions are realized cost effectively. Cost-containment design elements, such as an auction reserve price and price ceiling, will guarantee that the carbon price does not go above or below acceptable ranges. This approach will reduce administrative burdens for government. Virginia will be able to take advantage of economies of scale to reduce compliance costs while meeting GHG reduction goals while maintaining Virginia's autonomy and ability to act in its best interest. Linkability will also allow Virginia to take advantage of systems such as COATS without the need to develop and operate new systems and infrastructure. IETA encourages Virginia to establish an offsets policy and framework that could take advantage of existing methodologies developed by RGGI and the Western Climate Initiative. Over nearly a decade, RGGI has resulted in significant environmental and socio-economic benefits, including emission reductions and more than $2.76 billion in net economic gains. Virginia's cap and trade program can demonstrate that economic growth and carbon reductions can work together. As a global organization, IETA is aware of the broad and powerful role that programs like cap and trade can play in efforts to address the climate challenge. Adoption of 9VAC5-140 is a critical step that Virginia must take in order to reduce emissions and air pollution. At a time when Washington D.C. is regressing on climate action and leadership, Virginia's progress could not occur at a more important time	
114. Institute for Policy Integrity, New York University School of Law	When Virginia joins RGGI, the total emissions regulated by RGGI will rise by over 40%. Thus, the choice of Virginia’s emissions cap will substantially affect the total number of allowances available at each auction and may affect the stringency of the RGGI cap. Changing the stringency of the RGGI cap will, in turn, affect future permit prices, affecting all participants in RGGI auctions. In particular, power plants in other states will be able to purchase permits at a lower price, leading to less	Support for the proposal is appreciated, as is the commenter's discussion of trading programs.

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	abatement. Therefore, the achievement of environmental goals by RGGI will also be a function of Virginia's cap choice. A new state joining RGGI could either increase or decrease the stringency of the total emission cap. The RGGI price is currently below the socially optimal price for a ton of CO_2, and the price ceiling in RGGI is also below this level, so a less stringent cap would result in lower social welfare when compared to a tighter cap. If Virginia's cap is set relatively tight, leading to a lower total number of allowances than required to maintain RGGI's stringency, then RGGI permit prices will increase, possibly even hitting the price ceiling. This would not constitute an inefficiency from a social point of view. In 2020 the Social Cost of Carbon will be $49. Even if the generators were paying the full CCR trigger price, which in 2020 will be $10.77, the permit price would still be too low to fully internalize the externality caused by carbon emissions. By the same token, depressing the allowance price by decreasing the stringency of the cap would lower social welfare. If Virginia chooses to issue allowances for more emissions than its generators would emit under a business-as-usual scenario (the "counterfactual emission level"), this will loosen the emission cap for all of RGGI. Unless allowance prices are at the price floor, the price will go down, causing the aggregate emissions to increase compared to a scenario where Virginia does not join RGGI. A fall in the permit price will also decrease the revenue that the other states receive from RGGI auctions. The magnitude of those adjustments will depend on the magnitude of the changes in RGGI's cap. For emissions to decrease, the number of permits issued in Virginia must be set below the counterfactual emission level. To achieve that goal, a reliable prediction of the future emissions path is required. However, developments that can significantly affect Virginia's emission levels are uncertain, for example the rate of fossil fuel retirements and additions of renewables. DEQ should discuss their forecast of state CO_2 emissions to help assess whether the allocation will be too high or too low. Virginia proposes to set the base budget at 33 or 34 million allowances (while putting an additional 3.3 to 3.4 million allowances into the CCR). This might be too generous, even when future declines in the budget are considered. For instance, comments submitted to RGGI by Arcadia Center, NRDC and Sierra Club suggest that 2020 baseline should be set in the range of 30-32 million tons. The choice of the initial budget needs a sound justification given its potential impact on total pollution and permit prices. The allowance price will decrease slightly even if Virginia	

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	sets the cap equal to or just below its counterfactual 2020 emissions. This effect operates through two channels. Cheap pollution abatement possibilities may exist for Virginia's electricity generators that have already been implemented in the other RGGI states. And, if the RGGI cap is more restrictive than the cap chosen by Virginia, the total effective cap will be less stringent than without Virginia joining the system. However, the price decline will not be accompanied by an increase in total emissions compared to the scenario without Virginia. Therefore, a falling permit price, by itself, will not be informative as to whether RGGI's expansion will decrease total CO_2 emissions. As RGGI prices are already close to the reserve price, if Virginia enters RGGI with a loose cap, this will increase the probability of the ECR becoming operative. As Maine and New Hampshire do not intend to implement the ECR and will thus not withhold allowances when the trigger price is reached, this will create redistributional effects between the states. Adding Virginia generators to RGGI will improve market efficiency for current RGGI states and will help Virginia cost-effectively meet its carbon pollution reduction goals. Because of the consignment auction mechanism being used to distribute conditional allowances and RGGI proceeds, the SCC should ensure that all participants in RGGI are on an equal playing field to maintain market efficiency. One concern with the consignment auction is that some power generators in Virginia might be able to keep the revenue disbursed by RGGI, while, ideally, the consignment process should be revenue neutral for all compliance units. Regulated power producers in Virginia will be required by the SCC to pass all revenue from RGGI auctions on to state electricity consumers. The SCC will be in charge of verifying that the consignment auction is indeed revenue neutral for those units. Vertically integrated utilities could potentially gain revenue from the auctions by substituting RGGI-derived revenue for other customer support payments. Only newly conceived customer support programs should be funded using RGGI revenue to ensure that the support is additional to any other support that the generator might have offered. The SCC will need to be proactive in protecting Virginia consumers to prevent behavior by generators that results in windfall revenue. Windfall revenues would place the producer at a long-run competitive advantage relative to electricity generators that participate in RGGI but that do not receive revenue from the auctions. Because conditional permits will be allocated based on electricity generation rather than CO_2 emissions, clean generators could even see their profits increase if they manage to receive revenue from RGGI. This could happen for a generator that receives more conditional allowances than it needs to buy from RGGI to	

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	cover its own emissions, consequently receiving more revenue from RGGI than it spends at RGGI auctions. If non-regulated, private generators in Virginia subject to the proposed regulation do not have a revenue neutrality requirement, those generators will receive a revenue windfall in the form of proceeds from RGGI auctions. Some of the cleanest private resources might experience a profit windfall. As a consequence, this might create a competitive advantage for private generators over regulated resources. This could send incentives for new private power generation to locate in Virginia rather than RGGI states. Even if these generators receive revenue from the auction, joining RGGI will improve market function relative to the current status quo. Right now, emitting generators in Virginia are receiving an implicit subsidy, as they are not paying for the environmental damage caused by their emissions. Internalizing this externality will eliminate the perverse incentives for high emitting generators to locate themselves in Virginia relative to other RGGI states. The pass-through of the permit price from generators to customers will determine the extent to which generators themselves face the incentive to reduce carbon emissions. If the SCC allows generators to increase electricity rates in response to the costs of purchasing RGGI permits, then consumers will face an incentive to reduce electricity consumption and invest in energy efficiency. At the same time, higher energy prices may slow down the rate of electrification of the automotive and heating sectors. To the extent that the SCC wants the incentive for abatement of CO_2 to fall on the generators, it should limit the pass-through of permit prices to consumer electricity prices, either through limits on the approved rate increases by regulated generators or through rebates of RGGI proceeds to consumers. Similarly, if Virginia aims to increase electrification of other sectors of the economy, it should prevent pass-through of permit prices to consumer electricity prices. Electricity generators in Virginia will be incentivized to reduce CO_2 emissions whether or not the consignment auction is fully revenue neutral. A requirement to hold a permit for each ton of CO_2 emitted provides a marginal incentive to reduce emissions. This marginal incentive to abate will be present regardless of whether generators receive lump-sum revenue from RGGI. The RGGI-derived revenue would affect the long-run profitability of the generators if it is not distributed to consumers, so over time higher or lower emitting generators may be more likely to enter or exit the market. However, the marginal incentives to abate will be realized as long as the requirement to hold a permit to emit is in place. Moreover, were Virginia not to place any price on carbon, it would impede efficient market operation by	

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	implicitly subsidizing fossil power generators in the state. Therefore, including Virginia in the RGGI trading program will help improve market function and promote a level playing field between generators. The way in which the revenue from the consignment auction is passed to consumers will also have implications for environmental outcomes and energy demand. If consignment auction revenue is passed to consumers on a volumetric basis, consumers will see a lower price for electricity, reducing the incentive to pursue energy efficiency but also preserving the incentive for electrification. The design of the regulation needs to balance those trade-offs. Finally, the consignment auction mechanism also creates different incentives among the generators inside Virginia. Because the permit allocations and updates are based on net electricity output, the cleanest fossil fuel plants will have an incentive to expand their generation compared to higher emitting generators. This incentive should make the Virginia fleet even cleaner, leading to quicker decreases in emissions. In sum, adding Virginia generators to RGGI will increase environmental quality and improve market efficiency.	
115. Lena Lewis	I strongly support implementing carbon cap and trade of power plants. I congratulate DEQ on writing strong carbon cap-and-trade policy that will move Virginia forward in protecting our citizens from the worst impacts of climate change. I support linking with RGGI, which has a proven track record of success in reducing carbon emissions while keeping state economies strong. The purpose of cap-and-trade is to cause people to make different decisions than they otherwise would without the cap. Exempting biomass will create an incentive to cut down more forests, and will create the incentive for more biomass plants to be built, or for plants to be converted from fossil fuel to exclusively biomass. This will increase the incentive to cut down forests in Virginia. In addition to removing CO_2 from the atmosphere, these mature forests provide many other ecosystem services, such as cleaner drinking water, reduced erosion, and oxygen production. Keep in mind that carbon is just one element among many in our ecosystems. Carbon policy that exempts biomass risks increasing the destruction of biodiversity in forest ecosystems and reducing other benefits that they provide. Proponents of biomass say that it is carbon neutral because the energy source will absorb CO_2 as it grows back. A large body of scientific literature explains that the truth is not so straightforward. One essential question is the time frame needed in order for a harvested forest to	Support for the proposal is appreciated. See, for example, comment 67 for further discussion of biomass, and comment 65 for more information on the industrial exemption. A base cap of 28 million tons tons has been selected; see the response to comment 37 for additional information. As discussed elsewhere, the purpose of the regulation is to control carbon pollution emitted by fossil fuel-fired electric generating facilities.

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	grow back enough to absorb all of the carbon released from burning. This time frame depends on many variables, including age of trees, species, amount of fossil fuels required to harvest trees, temperature, and growth rate of species. We are on the verge of a tipping point with climate change. Harvesting forests for biomass fuel will increase carbon emissions in the near term. In the decades it will take for those forests to reabsorb that carbon, the added CO_2 in the atmosphere will contribute to accelerated release of carbon from melting permafrost in the tundra and reduced albedo in at the poles due to melting ice cover. Some public comments express concern that including biomass in the carbon cap will hurt the paper industry and tree farmers. The point of a market-based solution is to change behavior. If paper factory owners assess that carbon allowances no longer make it profitable to burn residuals, they are not required to burn their wood waste. Nor are they stuck in a situation of profit loss. Paper factory owners are free to innovate to find new ways to use residual wood waste. They may discover a new application that brings in more money than burning waste wood. Market-based solutions such as cap-and-trade promote innovation. Exemptions do not. The climate crisis calls for innovation across all sectors of society, and should not exempt the paper industry or the biomass industry. Though Virginia does not currently have large power plants that incinerate municipal or industrial waste to produce energy, a cap that does not include them will promote their development. Because MSW burned for energy is predominantly plastic that could otherwise be recycled, it is a potential source of carbon emissions and would promote the destruction of otherwise recyclable materials. Rather than wait for these plants to be built before regulating them, the regulation should state that plants burning MSW and industrial waste must retire carbon allowances to do so. The level of the initial cap is important because subsequent reductions are percentages, not set amounts. DEQ's proposed initial cap of 33-34 million tons is based on the electricity utilities' flawed projections of energy demand. The point of the cap is to reduce carbon emissions, not to give utilities a new source of revenue through selling allowances. Such a high number of allowances will flood the market, reducing the clearing price of allowances in the RGGI market and reducing revenue for RGGI states. Furthermore, a cap of 33-34 million will not change Virginia’s carbon emissions. The cap must put downward pressure on carbon emissions from the first year. Virginia’s electricity consumption is growing very slowly. Expected electricity demand growth	

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	over the next 15 years is less than 1% a year. The DEQ scenario of 33-34 million tons assumes an annual growth rate of 1.9-3%. It does not take into account the amount of utility scale solar projects already in the construction pipeline, nor the increase in rooftop solar. Anticipated energy demand depends on which historical data is considered. When looking at 2012-16, one could conclude that energy demand is increasing. However, 2012 had a mild winter and cool summer. Energy demand from 2005-16 resulted in emissions of just under 32 million tons of CO_2. Therefore, the cap should be lower than 32 million in 2020 to account for increased solar and natural gas, and to put downward pressure on emissions from the first year. Even if a business-as-usual scenario predicts a decrease in carbon emissions, the purpose of a cap is to decrease carbon emissions by a greater amount than under business as usual. Therefore, I recommend a starting cap of 30 million tons.	
116. Malin Moench	My comments go to the relative harm that coal, natural gas, and biomass do to the climate and to human health from the toxins that they generate when they generate electric power. Incentives should double down on energy efficiency and on renewables that are truly clean. The Clean Power Plan provided for gas-shift emission rate credits for utilities that replace coal-fired production with gas turbine production. Virginia's plan should not include such credits. Producing and burning natural gas is as climate forcing as coal largely because the effect of fugitive methane is far bigger. About 3.8% of conventional natural gas production and about 12% of shale gas production is fugitive methane. After properly accounting for fugitive methane, and using a 20-year impact analysis, it may very well be that gas-shift penalties are needed, rather than gas shift credits. Biomass should not be eligible for renewable energy credits. Burning wood scraps for power is not climate neutral. Per Btu, it emits 10-35% more CO_2 than burning coal, depending on the moisture content of the fuel, combustion efficiency of the plant, and processing losses. Regrowth of clear-cut hardwood forests will not offset the higher CO_2 intensify of burning wood scraps until the year 2100. By then, under current CO_2 emission trends, the world will have blown past critical tipping points in the carbon cycle. Burned biomass also exceeds coal in its emissions of toxins. Like coal emissions, wood smoke is an extreme public health hazard, containing over 200 toxic chemicals and particulate matter. The component of burned biomass that harms human health the most is fine particulate matter. Wood-fired power plants and coal-fired power plants are primarily neurotoxin and carcinogen factories from a physician's point of view, but	The commenter's observations about biomass are appreciated. Although toxic and criteria pollutants from biomass are indeed a source of concern, they are not regulated by this particular program, nor is methane. These pollutants are more appropriately addressed in other areas of the board's regulations. See the response to comment 67 for more detail.

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	on a Btu-equivalent basis, wood-fired is much worse. They should not get a free pass.	
117. National Alliance of Forest Owners (NAFO), Virginia Forestry Association (VFA)	Excluding biomass CO_2 emissions is good environmental policy and supported by scientific studies. There is an extensive record supporting a decision to differentiate biogenic CO_2 emissions from fossil fuel GHG emissions. Importantly, there is scientific consensus that, because it is part of the natural carbon cycle, the potential for impacts on atmospheric GHG levels from biogenic carbon is fundamentally different than fossil carbon. In the forests of Virginia, biogenic CO_2 emissions are more than balanced by carbon sequestered in growing forests. Studies show that combusting biomass for energy offers substantial GHG mitigation benefits when compared to fossil fuel. There is strong evidence that forests are currently being managed sustainably and will be for the foreseeable future. Thus, when forest carbon stocks are evaluated over appropriate time and spatial scales, there is ample support for the proposition that forests are capable of meeting increased demand without reducing overall forest carbon stocks. It is well-established that all wood products, including biomass combusted for energy, are part of the natural forest carbon cycle. CO_2 is sequestered in forests through photosynthesis and emitted through decomposition and combustion. As long as forest carbon stocks remain stable or increase over time, biomass energy and other forest product uses do not increase atmospheric GHG. In contrast, CO_2 emissions from fossil fuel combustion permanently increase atmospheric GHG concentrations because they release carbon that has been geologically stored for millennia. Sustainable management of forested lands provide distinct climate change mitigation benefits which reduce net GHG emissions over time: 1) durable forest products continue to store carbon for decades after harvest, 2) manufacturing forest products is much less carbon-intensive than alternative products such as concrete or steel, and 3) biomass used for energy can directly displace fossil fuel emissions over multiple harvest cycles. Many studies evaluating biomass energy have found significantly lower net GHG emissions when compared to fossil fuel. Recent studies have attempted to quantify in absolute terms the GHG mitigation benefit of substituting biomass energy for fossil fuels. These studies also identify substantial reductions in GHG emissions, but do not directly answer the question whether biomass combustion for energy results in any net CO_2 emissions. However, these studies consistently conclude that active forest management focused on supplying forests products and biomass energy produces the greatest GHG mitigation benefits from forested lands. Stability or growth in forest carbon stocks is essential for establishing that biogenic CO_2 emissions do not increase	See comment 67 for further discussion of biomass.

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	atmospheric CO_2. If forests are converted to other land uses after harvest, the carbon cycle is broken. Thus, given urban development and other external pressures, it is essential to ensure that forest carbon stocks are not depleted as a result of biomass energy. However, projections by the U.S. Forest Service suggest that forest stability will continue for decades to come. Whether viewed nationally or regionally, studies consistently find that forest carbon stocks have remained stable or increased over the past 60 years despite increases in demand for forest products. Timberland in Virginia has a highly positive net growth/removal ratio, meaning that through sustainable management, our forests are growing more than twice as much wood as is harvested. Despite the stability in U.S. forest carbon stocks over time, some have expressed concern that increased demand for biomass energy will reduce the amount of carbon that would otherwise be stored in forests. However, these concerns are inconsistent with the market factors that influence forest management decisions. Studies have repeatedly found that forest owners will respond to increased demand for biomass energy (or any other forest product) by increasing production, and thereby increasing forest carbon stocks. In the case of biomass energy, such responses can include increased consumption of existing harvest residuals, increased productivity through management practices, and land use changes. Biomass energy relies on low-cost biomass feedstocks to remain competitive with other types of energy. Thus, biomass energy feedstocks are commonly composed of residues and other low-grade feedstocks. In contrast, high-grade trees are reserved for saw timber and similar products that command higher prices and generally result in products that store carbon for decades. Given the price differential between low-grade feedstocks and saw timber, it is unlikely that high-grade, mature trees would ever be harvested exclusively for energy production. While increased demand for biomass energy could increase prices to some degree, even optimistic projections would not raise feedstock prices to the point that landowners would manage forests for energy instead of saw timber. NAFO and VFA support the proposal to exclude 90-100% biomass-fired facilities from the rule. The proposal is supported by scientific consensus that biogenic CO_2 should be regulated as being carbon neutral and is consistent with the RGGI Model Rule. We understand that at least one other commenter has raised the issue of how emissions from biomass are treated under the proposal. NAFO and VFA are sensitive	

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	to the issue of emissions of all kinds from biomass materials; however, these issues that are beyond the scope of the proposal. The proposal addresses CO_2 emissions from electric power generating units in Virginia, not other pollutants. Pollutants like benzene and formaldehyde are governed by other federal and state regulatory regimes already being administered in Virginia. The board should continue to focus the proposed regulation on CO_2 emissions and let existing laws and regulations govern non-CO_2 emissions from electric power generating units. We encourage the board to allow operators that co-fire biomass with fossil fuels to deduct the biogenic CO_2 emissions from the total CO_2 emissions the unit must cover with allowances. It is consistent with carbon-neutral environmental policy, and would bring Virginia in line with the RGGI Model Rule, as well as other RGGI states like New York. The Department of Forestry recognizes the sustainable development value and economic benefits of promoting use of biomass and biogenic fuel sources in Virginia, stating that the "benefit[s] of expanded utilization of biomass include: [p]rovid[ing] new markets for waste wood, manufacturing residues, and materials from forest management activities; … [r]educ[ing] material going to landfills, being dumped or open burned, such as woody debris and other wood waste; [r]educes site preparation costs for artificial regeneration; [r]educ[ing] pollution compared to using fossil fuels …." Congress also understands the environmental and sustainable development benefits of biomass-based fuel. In a display of bipartisan support, Congress passed the Consolidated Appropriations Act of 2018, where it directed the Department of Energy, the Department of Agriculture, and the Environmental Protection Agency to "establish clear and simple policies for the use of forest biomass as an energy solution, including policies that (A) reflect the carbon-neutrality of forest bioenergy and recognize biomass as a renewable energy source, provided the use of forest biomass for energy production does not cause conversion of forests to non-forest use; (B) encourage private investment throughout the forest biomass supply chain … (C) encourage forest management to improve forest health; and (D) recognize State initiatives to produce and use forest biomass." Encouraging the biomass fuel market to grow in Virginia will continue to help the board achieve the purpose of the regulation: "to control CO_2 emissions in order to protect the public's health and welfare." As reported in The Economic Impact of Virginia's Agriculture and Forest Industries (2017), "Biomass energy production has emerged in recent years as a	

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	significant new market for surplus wood residues in Virginia. Federal clean and renewable energy programs and Virginia's voluntary Renewable Portfolio Standard offers incentives to the state's power companies to produce electricity from renewable resources. Woody biomass accounted for most of Virginia's renewable power generation in 2015 and approximately 5% of total power generation in the state. Since 2012, Virginia has added over 300 MW in electrical power generation capacity." Also, "Virginia hosts 10 wood pellet plants, most of which have been established in the last decade. Collectively, they processed over 1.4 million tons of wood, mill, and forest residues." NAFO and VFA can vouch that a broad range of robust markets for all Virginia wood and fiber are in the best interests of forest health and sustainability, the economic prosperity of the state, and the welfare of citizens of the state. Markets for low value wood that may not have other outlets are critical to woodland owners and to lumber manufacturers searching for purchasers of sawmill residues. Energy production from woody biomass aids in reducing the threat of wildfire and insect infestation, and can enhance wildlife diversity. It is vital to have markets for wood during the clean up of biomass debris resulting from natural disasters. By exempting biomass-only and near biomass-only facilities, the board has demonstrated that it agrees biogenic emissions are inherently different from fossil fuel carbon emissions. We urge the board to consistently apply these conclusions by allowing operators that co-fire biomass with other fuel sources to deduct their biogenic emissions when calculating compliance. This policy has already been developed in the RGGI Model Rule and in 6 of the 9 RGGI states. Virginia would be an outlier by disallowing biogenic CO_2 deductions. Since RGGI began, it has engaged working groups to develop Model Rules that can be reviewed, adapted, and implemented by states joining the system. Many stakeholders participate in these reviews and many states have chosen to adopt in full substantive provisions of the Model Rule. In every iteration of the Model Rule, RGGI has allowed operators that co-fire biomass with fossil fuels to deduct the emissions attributable to biomass from the total amount of CO_2 emissions for compliance purposes. The RGGI Model Rule is not an abstract framework; most states that participate in RGGI have adopted it almost verbatim and implemented it with great success. The rule should allow operators co-firing biomass with fossil fuels to deduct biogenic emissions from annual CO_2 compliance accounting. It is consistent with the environmental and economic policies built into the regulation. NAFO and VFA encourage the board to add a definition	

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	of biomass. This will add clarity to the issue of biomass exemptions and allow the board to more easily review the exclusion of biogenic emission from CO_2 co-firing facilities. The legislature has already provided such a definition in VA Code § 10.1-1308.1.	
118. National Council for Air and Stream Improvement, Inc. (NCASI)	The rate at which global CO_2 emissions are increasing and the implications for global temperatures in the near- and long-term has led to calls for steep near-term reductions in emissions. IPCC indicates that, with respect to emissions of CO_2, it is cumulative emissions that will determine peak global temperature. IPCC notes that, "…taking into account the available information from multiple lines of evidence . . . the near linear relationship between cumulative CO_2 emissions and peak global mean temperature is well established in the literature and robust for cumulative total CO_2 emissions up to about 2000 petagrams of carbon. It is consistent with the relationship inferred from past cumulative CO_2 emissions and observed warming, is supported by process understanding of the carbon cycle and global energy balance, and emerges as a robust result from the entire hierarchy of models." IPCC indicates that, "A number of papers have found the global warming response to CO_2 emissions to be determined primarily by total cumulative emissions of CO_2 , irrespective of the timing of those emissions over a broad range of scenarios." One study cited by IPCC states that ". . . the relationship between cumulative emissions and peak warming is remarkably insensitive to the emission pathway (timing of emissions or peak emission rate). Hence policy targets based on limiting cumulative emissions of CO_2 are likely to be more robust to scientific uncertainty than emission-rate or concentration targets." It is only by reducing cumulative CO_2 emissions and thereby peak global temperature that ecological tipping points can be avoided. Near term increases in CO_2 that allow later reductions in cumulative CO_2 emissions are different from those that do not. In this context, it is not uncommon for increased use of forest bioenergy to result in near-term increases in atmospheric CO_2, compared to continued use of fossil fuels. However, as long as land remains in forest, increased use of forest bioenergy to displace fossil fuel accomplishes longer-term reductions in cumulative CO_2 emissions. The time required for increased use of forest bioenergy to transition from net CO_2 emissions to net CO_2 reductions depends on a number of factors. In the case of certain residual materials, the transition is essentially immediate. In other cases, this transition requires more time. Increased use of forest bioenergy to displace fossil fuels is likely to result in net benefits to atmospheric CO_2 within a decade or two. After this transition is completed, the benefits of forest bioenergy continue to accrue.	See comment 67 for further discussion of biomass.

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	Even critics of forest bioenergy acknowledge the long-term benefits of displacing fossil fuel with forest bioenergy. A report prepared on behalf of the National Wildlife Federation and SELC, for instance, found that "…using southeastern forests for an expansion of electric power generation produced a significant long term atmospheric benefit, but at short term atmospheric cost." In the this study, a 35- to 50-year breakeven period was estimated, but this study did not account for reduced deforestation and increased afforestation associated with increased demand for wood, a well-documented phenomenon. Near-term increases in CO_2 emissions must be judged in the context of whether they are associated with reduced cumulative CO_2 emissions in the longer term. This is because of the insensitivity of global temperature to near-term CO_2 emissions, and the need to reduce cumulative CO_2 emissions to limit peak global temperature. These considerations are directly related to questions about biogenic CO_2 resulting from increased use of forest bioenergy. Increased use of forest bioenergy often results in higher near-term CO_2 emissions compared to continued use of fossil fuel but, as long as land remains in forest, cumulative CO_2 emissions are reduced in the longer term when fossil fuels are displaced by forest bioenergy. This phenomenon needs to be considered when contemplating potential regulation of biogenic CO_2 emissions from biomass energy production. The two cases in which emission profiles argue for differential treatment of biomass are 1) when the material used for fuel would have ended up being emitted to the atmosphere even if not used for energy production, and 2) when sustainable management of the biomass resource ensures that ongoing growth will remove equivalent quantities of CO_2 from the atmosphere. In the first case, the biomass emissions that would have occurred anyway will prevent fossil fuel emissions associated with producing the same amount of energy. In the second case, a sustainably managed resource grows biomass equal to or exceeding the amount of biomass harvested, ensuring that the resource is not a net source of CO_2. In both cases, it is the characteristics of the biomass feedstock, not the characteristics of the power generation process or facility, that support treatment as carbon neutral. By exempting facilities using 90% or more biomass feedstock, the regulation implicitly acknowledges the environmental and atmospheric benefits of biomass compared to fossil fuels. The regulation takes an all or nothing approach: either all of a facility's emissions are exempt (if it uses 90% or more biomass fuel) or none of	

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	its emissions are exempt. This removes any incentive to use biomass as part of a fuel mixture in fossil-dominant plants. We have evaluated the carbon stock in trees on timberland across the U.S. South. Carbon stocks increased from 4.9 billion to 5.6 billion tons from 2005-16, an increase of 14.5% over a period with an average of 104 million tons of carbon removed annually during harvests. Even if all the biomass harvested from the forest during this time was immediately converted to CO_2 and emitted to the atmosphere (far from the actual situation), the fact that forest carbon stocks continue to increase is proof that biogenic CO_2 from biomass removed from the forest is more than offset by removals of CO_2 from the atmosphere by growing forests. In Virginia alone, tree carbon stocks on timberland rose from 503 million tons in 2005 to 589 million tons in 2016, a net increase of 17% while carbon removals from harvests were 7.4 million tons annually. In summary, when biomass from residuals or from sustainably managed forests replaces fossil fuels, there are climate change mitigation benefits. A large body of scientific evidence supports the environmental benefits of biomass energy, regardless of whether the biomass is combusted alone or as part of a biomass-fossil mix.	
119. Northern Virginia Electric Cooperative (NOVEC)	While NOVEC's power supply portfolio is predominantly natural gas-fired, NOVEC is keenly aware of its responsibility to provide renewable energy; as such, NOVEC's waste wood-fired biomass plant, landfill gas-fueled generation, and solar energy resources provide over 8% of NOVEC's system energy requirements. The definitions of "fossil fuel" and "fossil fuel-fired" are appropriate and should not be modified. Waste wood-fired, biomass-generating facilities should remain excluded. NOVEC owns and operates a 49.9 MW generating facility in Halifax County that is fueled exclusively by waste wood products that come predominantly from logging operations. This facility provides a winning solution to the management of wood waste products and the production and delivery of renewable energy to the power grid. NOVEC's mission includes the provision of a low-cost, reliable, and environmentally sound energy supply. NOVEC built this facility in response to member requests for additional renewable energy in its resource mix. NOVEC located the facility in an area that was already active in logging woodlands to supply the construction, furniture, and paper industries. Doing so minimized the need to transport waste wood over long distances; a side benefit was an economic boost to local communities.	See comment 67 for further discussion of biomass.

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	NOVEC does not log for the plant's fuel. Instead, purchasers of high quality timber hire loggers to clear land and deliver the high quality round wood for lumber products. The remaining un-marketable wood, known as "slash," remains in the form of branches, limbs and stumps. The region that provides slash to NOVEC's facility produces more than 1 million tons of this waste product annually. Land owners typically want the slash removed, as leaving it in place reduces the amount of land available for growing the next generation of trees. Harvesting slash is superior to sending it to landfills, as the volume would fill up landfill capacity. While slash can be disposed of through uncontrolled burning, there is no control of SO_X, NO_X, particulates, or other emissions. The NOVEC biomass model is the best alternative to open burning or leaving slash in the forest. NOVEC purchases slash already chipped and delivered in truckloads. Small businesses create jobs associated with chipping activities and delivery of wood chips. The facility's air quality permit limits the amount of certain emissions that result from combustion of wood chips. The heat generated during uncontrolled burns is wasted. At the NOVEC facility the heat produced from the combustion is captured and converted to electric energy, reducing the amount of electricity needed from other power plants. Fly ash produced by the plant is used as a soil nutrient by nearby farmers. In summary, NOVEC's biomass power plant is a win for the environment, the local economy, and Virginia. As such, biomass should not be included in the definition of fossil fuels. NOVEC pays a forestry tax to the Department of Forestry that is used to fund the re-planting of trees throughout Virginia. The forestry tax can be viewed as a carbon tax that is already in place and paid by biomass plants. Young trees take in a higher amount of CO_2 compared to older trees for the same acreage. Combusting wood slash does not emit any carbon that is not already in the natural life cycle. Biomass plants in economically challenged areas provide jobs and investments as well as tax revenues for schools and other local government services. Unlike natural gas or coal, biomass fuel is produced close to the plants and the harvesting/chipping/delivery of slash is a significant economic engine for the locality and region.	
120. Northern Virginia Electric Cooperative (NOVEC)	Resolution of the unresolved revenues allocation methodology should be directed to the SCC for development of an equitable distribution formula that includes all electric utility ratepayers across the state. Even though the Regulatory Advisory Panel was unable to reach a consensus on a distribution approach for the revenue, the RAP ranked the following allocation goals as the two most important: 1) protect electricity customers, and 2) promote cost-effectiveness. The rules in this area reference the December 4, 2017,	DEQ appreciates the commenter's concerns, however, this issue is beyond the scope of the regulatory action and the authority to address it rests with the SCC.

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	presentation before the Joint Committee on Electric Utility Regulation; it stated that the "revenue received by CO_2 Budget Sources owned by regulated electric utilities flow to rate payers pursuant to SCC requirements." This statement failed to recognize that Virginia ratepayers served by utilities that do not own CO_2 Budget Sources but purchase power from the PJM wholesale power market (presumably the CO_2 Budget Source entities market for their power) would see their power prices increase as a result of these rules as currently envisioned but would be unable to mitigate the increases in power prices through an allocation of the auction revenue as would be available to a select group of Virginia ratepayers. Making this potential treatment of utilities and its customers that do not own CO_2 Budget Sources is arbitrary and capricious. Assigning the resolution of this matter to the SCC and tasking the SCC to finish the job of developing an equitable distribution formula that includes all ratepayers across the state can achieve both of the original objectives of the RAP.	
121. Natural Resources Defense Council (NRDC)	Because of immediate and growing health and economic dangers, Virginia law clearly encompasses CO_2 in its definition of air pollution. Limiting and reducing carbon pollution would also achieve the board's charge to prevent harm to public health, safety and welfare. Because of the health and economic dangers that unmitigated carbon pollution poses to Virginia's human health, its economy, and property, we broadly support the proposed rule, using the same means already proven effective in 1 in 5 states in the country: a sensible, achievable limit on electric sector carbon pollution, with subsequent annual reductions. NRDC supports DEQ's proposal to ensure allowances comport with, and are fully tradable on, RGGI's pre-existing platform, due to its low administrative costs, third party market monitor reports, and robust cybersecurity. NRDC recommends that the rule set a 2020 baseline of 28.0 million tons. In order to determine the state's business-as-usual emissions and an appropriate annual reduction trajectory, DEQ should review reputable data and projections to establish a baseline that is not artificially high. To do so, DEQ should rely on up-to-date estimates of what Virginia's business-as-usual emissions will likely be in 2020. Similarly, DEQ should avoid industry-derived emissions projections that appear to be set unrealistically high, such as Dominion's 2017 IRP. DEQ's own proposal of either 33 or 34 million tons in 2020 is similarly flawed. An incorrectly high year-1 baseline budget would undermine the entirety of the program and jeopardize Virginia's ability to access the marked benefits of linking with the larger RGGI market. To set an appropriate baseline, DEQ should consider multiple up-to-date projections. The federal EIA's Annual	Support for the proposal is appreciated. The baseline has been set at 28 million tons, as discussed in the response to comment 37.

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	Energy Outlook (AEO) from 2018 shows emissions decreasing in the Virginia-Carolina region by 27% between 2017-20. NRDC's IPM modeling, conducted by ICF, predicts similar emissions declines in Virginia between 2017-20. Preliminary results from NRDC's updated IPM modeling for Virginia (utilizing an updated 2018 data set) projects the state's power sector emissions to be 28.0 million tons in 2020. This more up-to-date modelling accurately reflects the reality of today's power sector in Virginia. Not only are additional coal retirements planned, but renewable energy installations are increasing, concurrent with recently lower or declining demand growth across the state in 2017. The factors of lower in-state electricity demand, persistently declining gas prices, and growing low-cost renewable energy resources mean the state's emissions will be well under 33 million tons in 2020. NRDC's IPM modeling supports the adoption of a 28 million ton baseline as a likely-to-occur starting point in 2020. A sufficiently ambitious program will drive significant economic and health benefits, including lower energy bills and rates, as well as improved public health resulting from cuts in co-pollutants like NO_X and SO_X.	
122. NRDC	DEQ must ensure the economic efficiency of the program by directing allowance value toward consumer benefit. Therefore, the proposal is correct to avoid imposing costs on Virginia families and businesses by awarding allowances directly to emitting generators for free. Doing so would allow the ultimate price of those allowances to be borne by Virginia families and businesses in the form of higher wholesale electricity costs, while providing a windfall profit to generators. NRDC therefore supports the consignment auction, as that mechanism provides an opportunity to recapture revenue that would otherwise be a windfall to generators. Indeed, these carbon allowances are inherently a public good, and thus their value must be captured and utilized on behalf of all Virginians. However, DEQ should amend the rule at 9VAC5-140-6215 to allocate allowances directly to distribution companies, based on pro rata share of load served, to ensure that allowance revenue goes directly to customer benefits. In order to ensure market efficiency and a transparent, undistorted allowance price that levels the playing field for all generators, achieve maximum economic efficiency for Virginia citizens through allowance allocation, and align with the Grid Transformation and Security Act of 2018, a standing Emissions Trading Stakeholder Advisory Group should also be established to monitor implementation and performance of the final rule.	The consignment auction is designed to be cost neutral, and RGGI employs various market control mechanisms to ensure a balanced and consistent flow of prices. In addition, Virginia is a regulated state; thus, it is the responsibility of the SCC to maximize economic efficiency for Virginia citizens. As discussed elsewhere, implementation and performance of the program will be continual, with RGGI program reviews and Virginia APA rule reviews providing opportunity for public comment should issues with program implementation be identified.
123. NRDC	Many forms of biomass fuel are used or under consideration in Virginia, including landfill gas recovery, agricultural plant residues and animal wastes, forest harvest residues, energy crops, whole trees, and industrial waste. Many of these feedstocks can generate	See the response to comment 67 for a discussion of biomass.

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	carbon benefits compared with fossil fuels, while others can have significant negative carbon impacts. We focus on "forest-derived" biomass, specifically, categories of forest-derived feedstocks used to produce electricity: 1) whole trees and other large diameter wood that would otherwise be used in merchantable end uses; 2) harvest residues that would otherwise be discarded or left to decay; and 3) industrial and mill waste produced at a forest products processing facility that would otherwise be burned. We support the proposal to require co-fired facilities to hold allowances for the CO_2 they emit, whether those emissions be from forest-derived biomass or fossil fuels. We urge Virginia to issue a final rule that covers the net carbon emissions from all utility sector biomass power facilities larger than 25 MW. Specifically, Virginia must account for the net emissions from forest-derived biomass combustion from power sector facilities greater than 25 MW, including both dedicated biomass-burning units and those that cofire with forest-derived biomass, and cover these facilities under the cap. We recommend that Virginia regulate net emissions from forest-derived biomass as follows: 1) CO_2 emissions from onsite waste that would otherwise be burned in an industrial setting without energy recovery will require zero allowances for each ton of carbon emitted; 2) CO_2 emissions from forest-derived residues that would otherwise decay will require approximately 0.69 allowances for each ton of carbon emitted; 3) CO_2 emissions from whole trees and large diameter materials that would otherwise have a merchantable end-use, including pulp, paper, fiberboard, engineered wood or lumber will require one allowance for each ton of carbon emitted. Virginia should also require EGUs to furnish to DEQ an estimate of the proportion of their total forest-derived feedstocks annually that fall into these categories. Finally, Virginia must reject sustainable forestry as a proxy for carbon impacts of forest-derived biomass. "Sustainability," however defined, is not a measure of carbon impacts.	
124. NRDC	DEQ should design an economically efficient program with minimal market distortions, maximizing consumer benefits through efficiency investments by allocating allowances to distribution companies, and driving significant levels of in-state renewable energy development. Leakage can be minimized through the cost-effective development of untapped, clean resources like solar and energy efficiency. To ensure the program does not inadvertently lead to increased fossil-based electricity imports, DEQ should establish an annual program review process to assess whether interstate power flows are shifting as a result of the carbon price. A modest price on carbon is but one of many variables that	By linking to RGGI, Virginia will be linked to and involved in basic RGGI processes such as the routine program reviews and monitoring for potential leakage; however, recognizing the potential for any possible leakage to have an impact on disproportionately affected populations, a provision providing for review of

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	can influence interstate power flows; any such analysis would need to account for those in a comprehensive manner. The RGGI states have already built in such emissions monitoring and reporting that assesses leakage, and we urge Virginia to do so as well.	impacts on such communities has been added. See the responses to comments 55 and 91 for further information.
125. NRDC	Climate change is inherently an environmental justice issue, as coastal communities and low-income communities ultimately bear the worst brunt of its impact. Therefore, the program should make significant cuts to CO_2 and ensure the consumer and energy efficiency benefits flow to the low-income citizens most impacted not just by climate change, but energy costs as well. Additionally, because CO_2 is not harmful in locally-higher concentrations, and there do not appear to be specific Virginia plants in proximity to at-risk communities whose capacity factors will increase under a carbon program, a carbon market in Virginia appears unlikely to create hot spots of pollution in frontline communities. And as the cap for carbon emissions is lowered, it can also create additional benefits of further reducing associated co-pollutants that cause health problems in communities close to their source. To ensure this is the case, the regular program review should also incorporate an annual environmental justice review. As RGGI demonstrates, it is good practice to build in regular program reviews to ensure the framework is working effectively. As Virginia adopts and implements its program, it may need to be adjusted over time, to ensure it is functioning efficiently and is driving significant and additional carbon pollution reductions. Program reviews can ensure that the cap is set and updated at the correct level to drive carbon emissions reductions beyond BAU, while maximizing the development of a clean energy economy. Virginia's program should undergo internal review on a regular basis, including stakeholder and public input as RGGI has done. The first review should occur in 2020, to review 2019 emissions and ensure the 2020 budget reflects the reality of Virginia's power sector emissions. As Virginia pursues linking with RGGI, it should integrate itself directly into that program's review processes.	As discussed in the responses to comments 55 and 91, Virginia will participate in RGGI program reviews, and a Virginia-specific program review will be conducted to ensure that EJ communities are monitored.
126. National Wildlife Federation and the Virginia Conservation Network	We applaud Virginia's plan to confront the growing threat of climate change by creating a carbon market that can link with RGGI. According to the National Climate Assessment, with 3 feet of sea level rise between 162 to 877 miles of roads could be inundated. Further, the gradual subsidence of coastal land in Virginia is magnifying the impacts of sea-level rise in the region. The rising seas threaten the coastal tourism industry in Virginia, a critical component of the state's economy. For examples, tourism contributed $1.4 billion to the economy of Virginia Beach in 2015, which resulted in $256 million in salaries and more than 12,900 jobs. Virginia's beaches and coastal waters also support 5 of	Support for the proposal is appreciated, and the commenter's observations on the threat of climate change are recognized.

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	the 7 sea turtle species found worldwide. Every year between 5,000-10,000 sea turtles swim into the Chesapeake Bay. Most of these turtles are the threatened species, which depend on the bay for food and safety. The loggerhead sea turtle depends on the bay's sandy beaches and dunes for nesting habitat. As the sea level rises and extreme weather events occur more frequently, these nesting habitats are being washed away. Likewise, the bay is also experiencing the impacts of rising sea levels and warmer water. Warming temperatures and increased runoff from flooding are making the bay and its tributaries susceptible to harmful algal blooms--a threat to people and wildlife. These changes alter the abundance and migration patterns of wildlife in the bay, leading to declines in waterfowl and commercially important shellfish. Virginia is home to the U.S.'s largest clam aquaculture industry, with an average annual economic impact of $60 million; the seafood industry in Maryland and Virginia support almost 34,000 jobs. RGGI is a highly successful cooperative effort to harness market forces to cap, price, and curb harmful carbon emissions that are contributing to the climate change threats facing Virginia. RGGI states account for one-sixth of the U.S. population and one-fifth of the nation's GDP. Since the program began, RGGI states have experienced a net gain in economic growth, increased jobs, long-run electricity cost reductions, and decreased emissions. By establishing a program to trade carbon that will link with RGGI, Virginia can enjoy the benefits of a carbon trading system while adding momentum to the effort to mitigate climate change by ensuring that, with California's carbon pricing system and New Jersey rejoining RGGI, 1 in 3 Americans will live in states with carbon pricing policy designed to drive down carbon pollution. Tackling carbon emissions is important for avoiding dangerous levels of warming that will have high costs for Virginia. Though there has been a downward national trend in emissions from the power sector in recent years, carbon pollution from Virginia's power plants has risen from 23 million tons in 2012 to 34 million tons in 2016 and is expected to rise to 37 million tons in 2019. Linking to RGGI will reverse this trend for Virginia, propelling it to become a world leader in clean energy development, protecting the state's treasured natural resources and wildlife while creating new jobs and boosting the state's economy. While RGGI is considered to be an excellent example of a multistate program that encourages innovation and collaboration, there are still areas in which it can be improved. As an independent state linking with the RGGI carbon market, Virginia would have a unique opportunity to strengthen and advance the	

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	program. By doing so, Virginia has the potential to cement itself as a gold standard for carbon pricing.	
127. National Wildlife Federation, Virginia Conservation Network	Virginia could provide a model to improve RGGI's approach to biomass. While some biomass practices can reduce carbon emissions compared to other fuels, other practices increase near-term emissions and degrade wildlife habitat. One model for carbon accounting is the Net Emissions Impact, which applies multipliers for each unit of carbon from different biomass feedstocks. We urge Virginia to consider the nuances of biomass and weigh the potential for negative repercussions. The demand for low-value wood for pellets is driving a shift in the southeast from natural forests to pine plantations--a significant downgrade in habitat value. Unrestricted harvests leave high conservation value species and ecosystems vulnerable to biomass harvests, particularly wetland forests like bottomland hardwoods. Research has found that biomass from southeastern forests takes 35-50 years before it performs better than fossil fuels. This is far too long to mitigate the impacts of climate change, and not in line with he governor's executive order to reduce carbon pollution. We encourage measures to protect wildlife and habitat while pursuing measures to address climate. The state can reinforce the RPS limit on non-waste feedstocks by applying it to its carbon market as well. The state should preclude biomass sourced from high conservation value areas, and limit growth in the biomass market to truly sustainable feedstocks. Virginia must establish best practices for biomass production that lead to benefits for both wildlife and climate.	As discussed in the response to comment 67, and discussed in great detail elsewhere, there are pros and cons associated with using biomass as fuel. DEQ agrees that some biomass practices can reduce carbon emissions, and should include measures to protect wildlife and habitat.
128. Old Dominion Electric Cooperative (ODEC), Virginia, Maryland and Delaware Association of Electric Cooperatives	ODEC and the Association have significant concerns regarding the impact of this regulation on the electric bills of its ultimate consumers. Even a modest increase in bills in the territories served by ODEC and member cooperatives will be problematic, and larger increases in costs will turn electricity into a luxury item. The Cooperatives' service territories are predominantly rural and residential. The majority of rural areas in Virginia have seen both a declining population and sluggish to negative economic growth. The Cooperatives' service territories have high numbers of low- and middle-income families, families and seniors on fixed incomes, and families suffering from unemployment and underemployment. The Cooperatives' service territories do not have significant non-residential loads--the service territories are over 80% residential. From 2011-15, many of Virginia's rural counties experienced negative job growth. Current Department of Labor Statistics show that many of the rural counties in Virginia have significantly higher unemployment rates than the urban and suburban areas of the state. Historically, most Cooperatives have per capita annual incomes that fall 22% below the statewide average. For Cooperatives that are more rural,	DEQ agrees with the commenter that costs to consumers are an important consideration, and has worked to develop a rule that minimizes costs while maximizing benefits associated with reducing carbon pollution. Implementing a cost neutral consignment auction is expected to minimize cost impacts to consumers. To the extent that power is purchased from a regulated entity in Virginia, costs will be controlled through the auction and subject to SCC oversight.

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	that percentage is 260%, and for three of the most rural Cooperatives, the percentage is 30% or more below the statewide average. Historically, 13% of Cooperative member-owners are over 65 years of age, and unemployment in Cooperative territories is generally 1-4.5 percentage points above statewide unemployment rates. Based upon the 2010 Census, median household income in rural areas is less than half that of the suburban counties. Concerns over increased costs to consumers are not simply based on future projections. EIA Power Monthly indicates that there is already price pressure indicated on electric rates in RGGI participating states. Every state that participates in RGGI had average retail rates higher than the national average and 4 out of 5 of the states with the highest average retail rates in the U.S. participate in RGGI. The Cooperatives have only their ratepayers from which to recover costs; there are no separate stockholders. Furthermore, electric distribution cooperatives receive their generated electricity by contract. These contracts directly pass on the costs of any regulatory or environmental compliance to the distribution cooperatives, which then recover that cost from their consumers through a cost recovery mechanism in electric rates. Smaller cooperatives, including those wholly dependent on investor-owned utilities for their electricity, could be hit especially hard, as the costs of the regulation could be passed directly to those cooperatives and their consumers, with no mechanism for those suppliers to pass through proceeds from any sales of allowances back to the distribution cooperatives or their consumers.	
129. ODEC et al.	There is no modeling that can show the projected local benefits based upon the anticipated program reductions. The modeling for economic impact of this type of regulatory effort can be severely compromised based upon a variety of unknowable factors: market assumptions, regional power flows, projected resource mix, and demand considerations. In this case, there has been very little analysis done to support the anticipated and likely impacts on electric rates. The limited modeling that has been done could be significantly understating the impacts of the regulation, and by the time we see the results, it will be too late to make adjustments. We recommend a more holistic analysis be performed encompassing total energy consumption. Potentially higher future electric costs may produce unintended consequences in the form of shifts in energy usage or choice of fuel. An example would be a homeowner having an efficient electric heat pump choosing to produce some of the heat for their home via natural gas, propane, oil, or woodstove. In addition to the potential for additional emissions from these other alternate energy sources, one would also see increased CO_2 emissions	DEQ understands that impacts on electric rates are important, and several cost/benefit analyses were conducted; see response to comment 61 for more information. No significant impacts to consumers are anticipated.

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	from the delivery/transportation of these sources.	
130. ODEC et al.	Regulating CO_2 at the state level is not as effective as a broader regional or national approach. Putting this additional burden on Virginia generation will encourage imports from other states, potentially requiring the construction of additional transmission infrastructure to maintain reliability. This is already occurring where the RGGI regulation in Maryland has contributed to the construction of new transmission lines to facilitate the import of power from adjoining non-RGGI states. PJM, as a regional transmission organization, allows for cost-effective exchange of electricity throughout its territory, which includes the majority of Virginia. Inconsistent state CO_2 policies within PJM create distortions in generation dispatch that can increase regional emissions. For example, the cost of CO_2 allowances from the RGGI program in one state can discourage a low-emitting in-state natural gas plant from operating, only to make way for imported coal power from a neighboring state because the out-of-state plants do not incur CO_2 cost. We recommend adding a provision for an analysis of trends in imports in Virginia once the program has been implemented. If there is a significant increase in imports, Virginia should be able to adjust the regulatory requirements for in-state generators to deter the import of out of state generation. The board should consider "safety valve" measures--for consumer protection from price increases, for reliability of the electricity system, and for imports from out-of-state. The additional burden of this program could result in premature retirement of coal facilities, such as the Clover Power Station. These plants were designed, built and permitted in compliance with federal and state regulations to meet long-term electricity needs. This regulation may reduce the remaining useful life of these assets which are still being paid for by our consumers. Virginia needs to develop a mechanism to compensate consumer-funded prematurely-retiring coal generation. One possible way would be to carve out allocations for retired consumer-funded generation for a significant number of years after their retirement. This would remove a barrier to the closure of consumer-funded coal generation by providing allocated allowance revenue to offset the stranded costs. Other mechanisms would likely require legislation to implement. Those renewable generation resources owned directly by Cooperatives should continue to be counted as renewable resources and excluded from the proposed regulation. This includes not only solar PV projects, but also the NOVEC wood waste biomass plant in Halifax County.	Virginia's program is not at a purely state level; rather, Virginia is linking to a larger group of states in order to leverage its carbon control abilities to the maximum. As discussed elsewhere, leakage will be monitored for and addressed as needed; see, for example, the response to comment 91. If the cost of allowances become too high the CCR is triggered; see comment 136 for more information. DEQ agrees that existing coal plants were designed, built and permitted in compliance with federal and state regulations to meet long-term electricity needs. Most of Virginia's coal fleet is owned and operated by Dominion Energy, which has the ability to adjust its electric generating portfolio to meet its business needs while protecting its customers' interests. See the response to comment 67 for additional discussion of biomass.
131. ODEC et al.	While it is true that some form of consignment auction has been used for other allowance programs, it is a wholly new concept to "link" Virginia to RGGI. We do not believe that the mechanisms that will have to be put in	The consignment auction is designed to be cost neutral. This approach has been carefully crafted to

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	place to track allowances, as well as the increased burden on DEQ, have been fully factored into the cost of the program. Additionally, administrative costs have not been fully analyzed. Given that Virginia is not joining RGGI, but "linking" to it, we are unsure how administration of the consignment would be paid for. DEQ has no mechanism to recover its own administrative costs. As a not-for-profit cooperative, ODEC is exempt from federal income taxes as long as it receives no more than 15% of its revenue from non-members. This rule applies to all of the electric distribution cooperatives in Virginia. Cooperatively-organized businesses are designed, from their foundation, to serve their members, who are also their customers. Therefore, ODEC has concerns about the potential accounting and tax impacts of receiving "revenue" in the form of proceeds from the RGGI auctions. This concern would apply to any cooperatively-organized entity receiving auction proceed revenues. To the extent that the regulation maintains the concept of a consignment auction, consideration should be given to this unintended consequence. A solution could be to allow cooperatives to offset any allowance requirement with an equal amount of allocated allowances without the requirement to auction the allowances.	minimize costs. Program design elements such as the unlimited banking of allowances may mitigate this issue further.
132. ODEC et al.	Virginia has seen a downward trend in energy consumption and CO_2 emissions. Virginia's energy resource mix is evolving, with more investments in clean energy resources and renewables, regardless of CO_2 regulation. As reported in January 2018, Virginia has reduced its overall CO_2 emissions from all energy-related sources from 123.1 million tons in 2000 to 103.0 million tons in 2015. That 16.3% reduction ranks Virginia as the 16th highest reduction among all states and significantly higher than the national average reduction of 10.3%. This includes all energy related sources of CO_2 emissions including utility generation, transportation, industrial, commercial and residential sources. Even more impressive is the reduction in average CO_2 emissions per person where Virginia reduced its average emissions per person by 28.9%, ranking it the ninth highest reduction in the nation and significantly better than the national average reduction of 21.1%. The current trends support the initial budget being set at 34 million tons. While the trend has been declining over the years, there has been a great deal of recent investment in new clean combined cycle generation that would be subject to the program. Virginia should be allowed to enter the RGGI program with a budget that is fair to Virginia given the current generation resources. Even with the budget set at 34 million tons, with the new generation assets, the goal will still be challenging. Given that Virginia generators are	The commenter correctly asserts that investments in clean energy resources and renewables are increasing. The 28 million ton cap, as discussed in the response to comment 37, was selected. The RGGI program already contains multiple "safety valves"; the program is continually monitored and adjusted in order to protect reliability and resilience. See also the response to comment 33 for a discussion of modeling and emissions.

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	just now entering the RGGI-linked program, the banking adjustments that have been calculated by RGGI and are being proposed to be applied to subsequent years, should not be applied to the Virginia budget. These banking adjustments are based on participants outside of Virginia banking more allowances than anticipated, and not the actions of any generators in Virginia. Such an adjustment should only be applied to existing RGGI participants. In addition, there should be a reliability and resiliency safety valve. Such a mechanism would recognize that overreliance on intermittent generation or a single fuel such as natural gas may negatively impact reliability and resilience. Analyses should be performed to assure that resiliency is maintained and that critical generation resources are not retired because of the regulation. In the case where retirement of critical resources is likely, adjustments to the allowance allocations should be contemplated.	
133. ODEC et al.	We generally support the provision establishing that 95% of the budget will be allocated to the generators. Particularly for the Cooperatives, revenues from the allocations will go directly to consumers. This is a critical means to reduce the net cost impact on electric consumers. Setting a price on CO_2 emissions as this program does is enough incentive for all sectors to seek ways to reduce emissions. Even when allocated allowances, utilities will still have an incentive to pursue low or non-emitting resources and energy efficiency measures. Not having allowances granted to such sources and forcing electric ratepayers to foot the bill for CO_2 emissions would be a significant cost impact and can be somewhat mitigated by allocated allowances to generators as proposed. Any utility with a wholesale power contract could be adversely affected by a system where their consumers pay for the costs of CO_2 emissions and receive nothing in return. This could be resolved by flowing auction revenues through applicable FERC ratemaking mechanisms using FERC Form 1 data.	Revenues will only be realized if there are excess allowances. It is beyond the scope of this regulation and the department's authority to direct auction revenues through FERC.
134. ODEC et al.	We recommend allocation based on emissions, not megawatts generated. Incumbent utilities have made significant investments under the existing regulatory compact to provide power economically and reliably to meet retail loads. There should be an appreciation for the value associated with these investments in electric generating plants. The conditional allocations being allocated on an emissions basis will provide a glide path for the existing resources to continue to operate within their remaining useful life, rather than having significant stranded resources. Coal generators would still have an incentive to operate efficiently since the allowance price will set the value of each ton of CO_2 emitted irrespective of who is given the allowances.	See comment 136 for a discussion of allocations.
135.	We analyzed Energy Information Administration (EIA)	See the response to

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Partnership for Policy Integrity (PFPI), Appalachian Mountain Club, Center for Biological Diversity, Dogwood Alliance, Michelle's Earth Foundation	2016 data on the fuels burned and energy generated from Virginia's power sector and calculated CO_2 emissions using EIA emissions factors for each fuel. To achieve effective carbon reductions, and to administer the program fairly, Virginia should cover all plants greater than 25 MW, including industrial facilities that generate heat and power, standalone bioenergy plants and waste-to-energy plants in the utility sector. This would reduce CO_2 emissions more effectively, remove incentives to re-fire fossil plants with biomass, and reduce air pollution at some of the most polluting plants in Virginia. Industrial power plants are a significant source of CO_2 in Virginia. As a whole, the industrial sector emitted 16% of power sector CO_2 in 2016. The proposal would exclude some of the biggest polluters in Virginia. For instance, the WestRock Covington plant would under the industrial exemption as a plant that generates on-site heat and power. This facility burns natural gas, bituminous coal, distillate fuel oil, residual fuel oil, black liquor, and wood, and was responsible for 7% of Virginia's power sector CO_2 emissions in 2016. The company brought a new 75 MW wood-fueled generator online in 2013, which led to a dramatic increase in wood consumption and emissions. The facility is a large source of conventional pollution, and has recently been penalized by EPA for excessive particulate matter emissions. Similarly, the WestRock West Point mill burns coal, black liquor, distillate fuel oil, natural gas, residual fuel oil, sludge waste, and wood solids. It was responsible for 3.3% of the state's CO_2 emissions but as an industrial burner would be exempt, as would be the International Paper Franklin mill, which emitted about 700,000 tons of CO_2 from black liquor and natural gas in 2016. Failure to cover dedicated biomass-fueled power plants will exempt a significant amount of CO_2 pollution from coverage, and, like the industrial exemption, give a free pass to some of the largest sources of air pollution. The 50 MW Halifax County plant is a standalone facility shown as burning less than 300,000 tons of wood in 2016 although its capacity is upward of 600,000 tons. The plant has recently been subject to consent decrees for air quality violations. Dominion operates the 83 MW Pittsylvania station, and recently converted 3 coal plants to burn biomass at Altavista, Hopewell, and Southampton, for a total of about 153 MW. Their combined permitted emissions annually were 253.2 tpy $PM_{2.5}$, 114.6 tpy SO_2, 1,237 tpy NO_X, 2,748 tpy CO_2e, and 129.4 tpy VOC. Dominion also built the 585 MW Virginia City plant to burn up to 20% wood with 80% fossil fuels; this facility would need to purchase allowances for biomass-derived CO_2 under the plan. The plan also apparently exempts plants that generate electricity by burning municipal waste, a portion of which	comment 65 for a discussion of industrial facilities, and the response to comment 67 for a discussion of biomass. The regulation has been amended in order to address CHPs with more clarity; see the response to comment 74.

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	is considered biogenic. Combined, biomass burned in Virginia facilities emitted over 8 million tons of CO_2 in 2016; the non-biogenic portion of municipal waste emitted another 1 million tons. However, under the Virginia plan, only about 2.5% of this CO_2 would be regulated under the cap--the approximately 230,000 tons emitted by co-firing biomass at Virginia City. Covering biomass will dramatically increase the plan's effectiveness because it will regulate a large source of CO_2, and remove an incentive for fossil-fired plants to use biomass. Burning biomass undermines efforts to reduce emissions because biomass fuels inherently emit a large amount of CO_2 per unit energy. In 2016, the top 3 highest-emitting categories of solid fuel per unit energy were biomass. When fuels are burned in a power plant, the efficiency of conversion of fuel to energy affects the CO_2 emission rate on an output basis. Wood-burning power plants are inefficient, in part because wood tends to have a high moisture content. This further increases the GHG impact of bioenergy. We also support including emissions from co-fired biomass. The high moisture content of biomass co-fired with fossil fuels can decrease the efficiency of the facility overall, meaning that it emits more CO_2 per unit energy. In comments to DEQ, Dominion claimed the following: "In 2013, Dominion made significant investments to converted three 51 MW units that used coal to 100% biomass, encouraged by EPA's prior determination that biomass was carbon neutral for PSD permitting. Close proximity to an ample supply of waste wood biomass as well as EPA's carbon-neutral policy for permitting under the PSD effective at that time were key economic drivers for these projects. Given Dominion's significant investment in renewable wood waste and forest residuals biomass, it is important for our customers that biomass emissions be considered carbon neutral." This statement highlights how treating bioenergy as having zero emissions is an incentive for more tree-burning power plants. Beyond that, it contains several inaccuracies. Dominion did not convert three "51 MW units that used coal." The units were 63 MW and the boiler de-rating that occurred with the conversion to biomass downgraded the units to 51 MW. It is not true that EPA had made a "prior determination that biomass was carbon neutral" when the Dominion plants were permitted. When EPA began regulating power plant CO_2 under PSD permitting in early 2011, biomass power plants were regulated alongside fossil fueled power plants--all the CO_2 was counted. In July 2011, EPA suspended regulation of CO_2 from bioenergy facilities under PSD for 3 years and convened a panel of its Science Advisory Board to advise the agency on how to regulate biogenic CO_2. EPA had not determined that	

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	bioenergy was carbon neutral--it admitted the topic required study, while suspending regulation. The suspension was challenged, and in 2013 EPA's regulatory deferral for biogenic CO_2 was vacated . The court identified nothing in the Clean Air Act that would allow EPA to exempt biogenic CO_2 from being counted when determining whether a facility meets the emissions thresholds that trigger PSD permitting. The permit for Dominion's first conversion (Altavista) is dated May 2012--prior to the ruling but concurrent with the court case. Dominion knew that EPA had not concluded that bioenergy was carbon neutral and knew there was a possibility that plants would be regulated in the future. Further confirming that Dominion knew the status of bioenergy GHG permitting was indeterminate, the company submitted comments to the Science Advisory Panel requesting that the panel make an a priori determination that biomass is carbon neutral. The issue was still in play in 2014, when EPA published an NSPS for GHG emissions. The NSPS both acknowledges the importance of feedstocks for net carbon impacts and conclusion of the panel that biomass cannot be considered carbon neutral. A 2013 article by a Dominion employee mentions several reasons for the coal plant conversions, stating "Benefits to the environment would include reductions in nitrogen oxides, sulfur dioxide, particulate matter and mercury"--but nowhere mentions a reduction in CO_2 emissions as a rationale. Perhaps this particular executive was aware of the skepticism that met Dominion's claims about bioenergy at the SCC when the company applied to convert the plants. In its application and 2011 testimony, Dominion made numerous claims regarding biopower. Dominion described that residues would decompose in 10-15 years, or 25 years for large logs, and that burning these residues should be considered carbon neutral. While this argument might be valid if Dominion's converted coal plants operated for a single year and then shut down, for facilities in continuous operation, the net cumulative atmospheric CO_2 loading over this period would be many millions of tons more than if the residues had simply decomposed. Dominion and other bioenergy proponents also argue that as long as forest growth exceeds harvesting, that burning wood should be considered as having zero emissions. When forests are cut and burned for electricity or heat, the forest bank's deposits are smaller than they would have been if the trees had been left standing, and there is more CO_2 in the atmosphere. When the bioenergy industry claims that current forest growth should be considered as offsetting bioenergy emissions, the bioenergy industry is effectively arguing	

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	that the bank's deposits can be transferred from one customer's account to another to cover up for the fact that some customers have withdrawn their money. This violates the concept that mass must be conserved. As the IPCC states, "If bioenergy production is to generate a net reduction in emissions, it must do so by offsetting those emissions through increased net carbon uptake of biota and soils." The biomass industry argues that the IPCC treats bioenergy as carbon neutral. The IPCC GHG reporting protocols count carbon loss from bioenergy in the land-use sector, when trees are harvested, and thus to avoid double-counting, does not count it in the energy sector--not the same as treating it as having zero emissions. The false representation of this position has become so pervasive that the IPCC has stated, "The IPCC approach of not including bioenergy emissions in the Energy Sector total should not be interpreted as a conclusion about the sustainability or carbon neutrality of bioenergy." DEQ's decision to count biomass emissions from co-firing should be extended to cover emissions from utility sector and industrial sector bioenergy emissions. Adding these plants would require raising the cap but should not entail other difficulties; the plants would simply increase the number of units covered, and should not interfere with the program's ability to interface with RGGI. Policy precedents for counting biomass carbon exist elsewhere. Massachusetts ended renewable energy subsidies for utility-scale wood-burning power plants in 2012, and the District of Columbia enacted a similar law in 2015. Treatment of bioenergy as having zero emissions under the E.U.'s carbon trading program has led to explosive growth of the wood pellet industry in the U.S. southeast, including Virginia. Forests, including areas that represent some of the most carbon-rich and biodiverse ecosystems in the U.S., are being clear-cut for biomass fuel. DEQ has gone part of the way toward regulating bioenergy emissions by proposing that co-fired facilities be required to hold allowances for 100% of the CO_2 they emit, whether it be from biomass or fossil fuels. We appreciate that DEQ has not repeated the mistakes of the RGGI program in allowing "eligible" biomass to be treated as having zero emissions when it is co-fired in electric plants and defining eligible biomass as sustainably harvested wood. "Sustainably harvested" is a largely undefined term and is not meaningful for carbon accounting. However, it is important for DEQ to cover all plants under the cap, including those that primarily or exclusively burn biomass. This might be facilitated by counting bioenergy net emissions under the carbon plan rather than stack emissions. Net emissions are a	

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	cumulative measure assessed over some time period, and represent the difference between stack emissions and emissions if the biomass underwent some alternative fate. Four categories of wood-derived biomass are defined by the alternative fate if the material is not burned in a power plant: trees that would continue growing or be harvested for another purpose; residues that would remain onsite to decompose or be burned; residues that would be incinerated; and residues that can be used for other purposes like mulch or particle board. This framework matches in part Dominion's argument about forestry residues that "Unless re-purposed for other uses, such as energy production, this material is often left on-site after a harvesting operation is completed and will eventually be burned on-site or nearby, or will decompose, releasing carbon into the atmosphere and turned into organic matter on the forest floor and soil." Emissions from burning residues for energy are significantly greater than those from decomposition over decades, and thus net emissions should be regulated. The NEI at year 10 is 70%, meaning that 70% of the direct stack emissions represent a net increase of CO_2 over that time period. Applying this figure to carbon trading would mean that facilities burning forestry residues would be obligated to purchase 0.7 allowances for every ton of CO_2 they emitted. For facilities burning materials where the alternative fate was incineration, the net difference between direct emissions and alternative fate emissions is zero. Since many industrial facilities burn residues that may be incinerated if not burned for energy, this provides an exemption based on a scientific rationale rather than an arbitrary exemption. We support counting CO_2 emissions at the stack as the best way to account for CO_2 emissions from industrial, waste-to-energy, and biomass facilities. Counting stack emissions is a closer approximation of the net atmospheric impact than the assumption that emissions are zero, which is the outcome of not regulating wood-burning power plants. Stack emissions are an underestimate of the actual net carbon impact of cutting and burning whole trees that would have otherwise continued growing and removing CO_2 from the atmosphere. As a secondary option, we support the NEI methodology because it is relatively simple, science-based, and would ensure that some emissions are counted even if companies claim to use residues and in fact use whole trees. It would also exempt facilities that burn materials where the alternative fate is genuinely incineration. Regulating these facilities is important because they can be large sources of CO_2, and need the same incentives as the rest of the power sector to reduce emissions.	

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	CHP plants contributed 22% of Virginia's power sector CO_2 in 2016, and electric-only plants emitted 78%. Most CHP plants are in the industrial sector; those not designated as industrial include Hopewell Cogeneration; Spruance Genco, a coal-burner; and Dominion's Southampton biomass power station, which reported a total heat input of 25% greater than its heat input for electricity only. This plant received 4% of its heat input from distillate fuel oil in 2016. DEQ will need to find a way to accommodate cogeneration plants outside the industrial sector even if the industrial exemption is maintained. However, we recognize DEQ not wanting to overregulate CHP if it leads to reductions in fuel burning. To incentivize CHP, DEQ should cover CHP plants, but provide a reduction in allowance obligations based on generation of useful thermal energy. It is not advisable to simply exempt CHP plants. Some plants may claim to operate as CHP plants, but not generate a meaningful amount of useful thermal energy. Many industrial sector CHP plants burn a variety of dirty and inefficient fuels. Subjecting these plants to trading will ensure that they seek to minimize emissions and generate energy from zero-emissions technologies.	
136. Resources for the Future	The regulation will distribute most of its allowances to compliance entities without charge. However, the allowances have conditional value that cannot be realized and the allowances cannot be used for compliance until they have been submitted on consignment to auction for sale. The state proposes to link with RGGI and the consignment to auction would be integrated as part of the RGGI auction. The compliance auction is a good option for Virginia if the state decides that it cannot directly auction allowances. Under the compliance auction, Virginia compliance entities that were the original holders of the conditional allowances will receive the auction value of their consigned allowances, once sold, in proportion to their original allowance shares. Those entities can purchase the allowances they need for compliance in the auction or in the secondary market. Virginia's consignment auction is not unique. Previous experience with consignment in emissions markets include the SO_2 trading program established under the 1990 Clean Air Act. In that program the emissions allowances were initially distributed without charge to compliance entities, but those entities were required to submit a fraction of their allocation under consignment to an auction held by EPA. In retrospect, economists describe that consignment auction as an important element of the overall program's marked success. Currently, the Western Climate Initiative runs an auction that is very similar in its basic design to the RGGI auction. In that auction, allowances that have been	The commenter's observations are appreciated. DEQ agrees that the updating output based allocation approach will effectively control CO_2 emissions while being cost-effective and transparent.

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	initially distributed to investor-owned utilities in California must be consigned for sale in the auction, with the revenue returned to the utilities on a proportional basis. The California auction also has a price floor and a cost containment reserve, and the program has worked without a problem. The consignment approach should integrate seamlessly with the existing auction in which allowances are submitted for sale by the RGGI states. The auction outcome does not depend on whether the sold allowances are submitted by a state or if they are submitted by a compliance entity through consignment. From the perspective of other buyers and sellers including the other RGGI states, the auction works equally well in either case. Consigned allowances from compliance entities in Virginia will also work seamlessly with other features of the RGGI program. The consignment auction approach is a valuable feature because it enables the price floor, the ECR, and the CCR to function seamlessly with respect to the aggregate supply of allowances, including both the consigned and state-held allowances. The consigned allowances will be indistinguishable from state-held allowances in the auction, and these auction mechanisms will affect all the allowances in the same way. The same price floor and price points for the ECR and the CCR can apply to the consigned and state-held allowances in like fashion. The consignment approach is transparent, in that all observers can witness the original holders of the allowances, as well as the flow of revenues back to the original allowance holders. This transparency has value to Virginia regulators and it enables evaluation of market performance that is regularly conducted by the RGGI market monitor. Moreover, the consignment approach creates a program design that could seamlessly segue to a revenue raising auction if the state were to choose to move in that direction. The regulation describes a CO_2 allocation methodology to distribute allowances among compliance units based on their share of total electrical output across all units that are eligible to receive an allocation. This "updating output based allocation" approach has been used in previous emissions trading programs including by some of the states in the NO_X Budget Program. This approach provides an ongoing incentive to reduce the emissions intensity of electricity generation. In this regard, it is far superior to an approach that would distribute the emissions allowances across compliance entities based on a static, historic measure of emissions or heat input. The proposal aligns incentives associated with the award of allowances with overall program goals and can be	

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	expected to improve program's cost effectiveness. An important motivation for using updating output based allocation is that it provides a production incentive, because the greater the production at a facility the greater the share of the emissions budget that would be awarded to that facility. Detailed simulation modeling at Resources for the Future has shown that this approach to allocation can mitigate potential leakage of electricity generation from the state. Because updating output based allocation provides an incentive to increase generation, it helps to mitigate leakage. Consequently, this choice of allocation method helps protect economic interests in the state while helping to achieve environmental goals. It also works well with the consignment auction. Under free allocation with a consignment auction, the Virginia compliance entities that were the original holders of the conditional allowances will receive the auction value of their consigned allowances, once sold, in proportion to their original allowance shares. Because most compliance entities are owned by companies regulated by the state, the value of the consigned allowances would contribute to meeting the revenue needs and thereby benefit electricity consumers. To strengthen this relationship between the source of revenues and their use, the state might require that some portion of the allowance value be invested in program-related efforts such as energy efficiency or renewable energy. In Virginia, the value of consigned allowances returns to regulated companies, and because of state regulatory oversight that value is expected to accrue to the benefit of rate payers. This outcome is somewhat similar to the practice in some other RGGI states such as Maryland, where a portion of allowance value has been returned on the electricity bill. In the future, if the program were to become substantially more stringent either as a regional program or as a model for a national program, the return to rate payers would be more substantial. However, if the value reduces the consumer’s monthly electricity bill, then from the perspective on consumers, their cost of electricity would appear to not reflect the carbon price. In turn, this would deny consumers the information they need to make decisions about energy-efficient investments in household appliances and in their regular electricity consumption. As a result, the regulation may have minimal effect on overall electricity demand. An alternative to returning the value of consigned allowances to the rate base and thereby reducing monthly consumer bills would be to return the value to electricity consumers on an equal and periodic (i.e., six	

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	month) per-customer-account basis. Consumers would see higher prices in most months, reflecting the value of allowances, thereby providing an incentive to conserve energy. Periodically, they would receive a dividend that preserves distributional goals and provides a program feature that is likely to be popular with recipients, which in turn builds constituent support for the program. The consignment auction preserves many of the benefits of a direct auction of allowances; however, a direct auction has further advantages. A revenue-raising auction would provide state agencies with financial resources to make investments in carbon mitigation, to address distributional goals, or to address the consequences of a changing climate. Public finance economists suggest that in the long-run, great value is associated with a tax swap, with revenues from the carbon price used to reduce other taxes in the state and thereby to help attract economic activity to the state. Another option would be to use revenues to provide dividends that directly compensate households as the common property owners of the atmosphere. The state of Virginia should consider an approach that would directly auction allowances to raise revenue to address these pressing needs to address the challenge of climate change. Two important elements of the RGGI program are provisions to contain emissions and costs when changes in electricity markets lead to outcomes that are unanticipated. The ECR constrains the quantity of allowances that would be sold in the auction when the auction price falls below a specific level. At an even lower price level, the price floor provides an absolute minimum price for the sale of allowances. As a complement, the CCR makes allowances available in addition to the intended cap if the auction price rises to a specific level. Together, these features make the supply schedule for emissions allowances responsive to the equilibrium price in the auction, which is a characteristic of commodity markets in general, but rare in environmental markets. Among other effects, this design helps to reduce price volatility in the allowance market. Empirically, the more important of these provisions is the ECR (and the price floor) because experience in emissions markets around the world shows a consistent tendency for prices to fall below expected levels. The ECR automatically restricts the supply of allowances if the cost of emissions reductions falls, and the CCR automatically expands supply if the cost increases. This feature helps boost confidence in the allowance market and reinforces the goals of the trading program in a transparent way by reducing emissions automatically when it is unexpectedly inexpensive to do so.	

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	The RGGI auction has a bid limitation that limits the share of allowances that any one entity can purchase to 25% of all allowances that are sold. This bid limitation is a feature to guard against potential manipulation of the auction or the allowance market. When Virginia links to the RGGI program, the bid limitation in the auction might not make it possible for all the Virginia compliance entities to rely strictly on the auction to acquire their necessary allowances if they chose to do so. Virginia should work with RGGI to amend this rule by expanding the size of the bid limitation such that every entity has the possibility of relying on the auction for compliance. A change from 25% to 30% should be adequate. That change would be modest, and will not create a meaningful possibility for market manipulation, because still, no single entity would constitute a sufficient share of demand in the auction to exercise strategic behavior. Further, the largest compliance entities in Virginia operate under cost-of-service regulation, unlike many other firms in the RGGI market that are IPPs. A regulated company would not have the same potential incentive for possible manipulation as would competitive companies because advantageous rewards would be expected to flow to rate payers rather than shareholders; this may lessen the incentive for strategic behavior and mollify potential concern. Nonetheless, the RGGI market monitor should remain vigilant about market disruptions due to manipulation or strategic behavior; however, the concentration in the market held by the largest entity after Virginia begins to participate in RGGI is not sufficient to increase that concern and the expanded size of the market overall should reduce concern. Given that Virginia's regulatory design is very complementary to the RGGI program, the only substantial issue is the relative emissions budgets of Virginia and RGGI when Virginia enters the program. Virginia and the RGGI states will want to look for the right balance among costs incurred by all the states. One of the reasons why the states conduct modeling is to anticipate this type of issue and plan for eventualities. Virginia and RGGI's actions model this and address forecasted emissions is the right process to provide analysis that can support decisions that enable the reduction of emissions on a broad regional basis. However, the assumptions in the modeling will directly influence the results and it appears that the scenarios that were modeled took a very cautious approach, meaning that they lead to forecasts for emissions that are greater than are likely to occur. On a national basis, the demand for electricity fell during the Great Recession but it has remained nearly level since then, reflecting a decreasing energy intensity of economic activity. In Virginia, demand has fallen and	

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	subsequently risen, where most of that rise has been associated with large data storage facilities. That increase is more than adequately represented in even the most modest forecast of demand growth by DEQ. A second factor is the emissions intensity of electricity generation in the state. Over recent years there has been a substantial growth in natural gas generation that has a lower emissions rate than coal. Much of the new natural gas has reduced imported power, but it has also reduced the use of coal for electricity generation in the state and that trend is expected to continue, and to result in the retirement of coal-fired capacity over the next few years. At the same time, a substantial growth in renewable energy resources is anticipated. Indeed, some of the companies associated with the recent growth in electricity demand for data storage are advocates of renewable energy and have pledges to their customers to link their consumption to expanded renewable generation. In summary, these secular changes appear to indicate that the state of Virginia is on a pathway that will see declining emissions soon. At present, Virginia is considering annual base budgets of either 33 or 34 million tons per year. The considerations I discuss point to the 33 million ton value for the base emissions budget; although a compelling case could be made that the budget could be lower still. Use of a consignment auction coupled with updating output based allocation for the initial distribution of emissions allowances is a strong design for the trading program. The value of allowances submitted to the consignment auction is expected to flow to the benefit of ratepayers, but as that value increases the state should consider separating the value from monthly electricity bills and return it to customers on an intermittent basis. There are additional benefits from directly auctioning allowances that could help the state address a variety of climate-related goals, and this should be considered also. An especially important feature of the RGGI program design is the ECR, which Virginia should support. There is a provision in the RGGI auction design that limits the bid quantity by a compliance entity; this provision could be inconvenient for RGGI and should be considered further in collaboration with RGGI. Finally, the lower of the two emissions budgets is more appropriate given current trends in the industry in Virginia, and an even lower budget could be justified.	
137. Regional Greenhouse Gas Initiative (RGGI)	The RGGI states applaud Virginia's progress toward implementing a market-based program to reduce GHG emissions. In considering Virginia's potential participation in our existing RGGI market, the RGGI states recognize many benefits of an expanded trading market, including increased economic efficiency and mitigation of the	Support for the proposal is appreciated. As discussed in the response to comment 37, the initial base cap has

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	possibility of emissions leakage. Participation in RGGI has helped our states create jobs, save money for consumers, and improve the public health, while reducing power sector emissions and transitioning to a cleaner energy system. If implemented successfully, expanded RGGI participation will serve to amplify these benefits. The RGGI states recognize the importance of ensuring that any new entrant into the RGGI market is fully compatible with our existing program. In studying Virginia's potential compatibility, we considered the alignment of key program elements, consistency in the use of regulatory language, and comparable stringency of the program as a whole. Expanding the RGGI trading market brings many benefits provided that compatible programs can be established. Making the changes outlined above to Virginia's regulation will help to ensure compatibility so that, as a regulatory matter, Virginia can be considered a RGGI Participating State. The RGGI states are excited by the prospect of Virginia's potential participation in the RGGI program, and applaud Virginia's plans for investment in complementary programs such as energy efficiency and clean and renewable energy. We see an opportunity for Virginia to realize a measure of climate leadership by adopting a lower starting allowance budget than the 33-34 million tons currently proposed. The RGGI states' comments have been informed by productive conversations with Virginia state staff and Agency Heads. States hope to continue the discussions in the future as Virginia makes further refinements to this proposed rule. The RGGI states are available to assist Virginia in addressing these comments as the state continues towards the development of a compatible program.	been set at 28 million tons.
137-1. RGGI	The proposed rule states at 6020 C: *"Allowance" means an allowance up to one ton of CO_2 purchased from the consignment auction in accordance with Article 9 (9VAC5-140-6410 et seq.) of this part and may be deposited in the compliance account of a CO2 budget source.* The RGGI states suggest that this definition be replaced by the following, in order to be consistent with the definition of "CO_2 allowance" in the 2017 Model Rule. This change would help ensure the proper functioning of the RGGI allowance market, including for purposes of tracking of allowances to be used for regulatory compliance with the RGGI program: *"CO_2 allowance" means a limited authorization by the* [REGULATORY AGENCY] *or a participating state under the CO_2 Budget Trading Program to emit up to one ton of CO_2, subject to all applicable limitations contained in this Part."*	The proposal has been revised accordingly.
137-2. RGGI	a. The proposal is silent regarding the potential use of CO_2 offset allowances. The RGGI states recommend that the Virginia rule specify that CO_2 offset allowances will be accepted for compliance, up to a maximum 3.3%	a. The proposal has been revised accordingly. b. The proposal has been

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	of any entity's compliance obligation. The RGGI states intend to amend the 2017 Model Rule to clarify the limit on offset allowance use. The RGGI states recommend inclusion of the following regulatory language on offsets, in order to be consistent with the to-be-amended 2017 Model Rule: *For CO_2 offset allowances, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of* [Section XX] *for a control period, initial control period, or an interim control period may not exceed 3.3 percent of the CO_2 budget source's CO_2 emissions for that control period or initial control period, or may not exceed 3.3 percent of 0.50 times the CO_2 budget source's CO_2 emissions for an interim control period, as determined in accordance with* [Subparts XX]. b. A definition of "CO_2 Offset Allowance" will be necessary to support inclusion of the offset language offered above. The 2017 Model Rule defines "CO_2 offset allowance" as: "*CO_2 offset allowance. A CO_2 allowance that is awarded to the sponsor of a CO_2 emissions offset project pursuant to section XX-10.7 and is subject to the relevant compliance deduction limitations of section XX-6.5(a)(3).* c. Note that these recommendations pertain to the fungibility and acceptance of CO_2 offset allowances for compliance under the RGGI trading program. The RGGI states leave it to Virginia's discretion whether Virginia wishes to establish state-specific offset protocols, and to issue CO_2 offset allowances to qualifying projects within the state. The proposed rule does not provide for the issuance of CO_2 offset allowances.	revised accordingly with some modification. c. As discussed in the response to comment 26, Virginia is exercising its discretion to not implement offsets at this time.
137-3. RGGI	The proposed rule states at 6020 C: *"CO_2 Budget Trading Program" means the Regional Greenhouse Gas Initiative (RGGI), a multi-state CO_2 air pollution control and emissions reduction program as a means of reducing emissions of CO_2 from CO_2 budget sources.* The RGGI states suggest that this definition be replaced by the following, in order to be consistent with the definition of "CO_2 Budget Trading Program" in the 2017 Model Rule. Because this defined term is part of the regulatory definition of "Participating State," this change would help ensure that Virginia is considered a RGGI Participating State and that Virginia-issued allowances are fully fungible across the RGGI program: *"CO_2 Budget Trading Program" means a multi-state CO_2 air pollution control and emissions reduction program established pursuant to this Part and corresponding regulations in other states as a means of reducing emissions of CO_2 from CO_2 budget sources.*	The definition of "CO_2 Budget Trading Program" has been revised accordingly with some modification. No change has been made to the definition of "participating state" because the need for corresponding regulations is addressed in the CO_2 Budget Trading Program definition.
137-4. RGGI	The proposed rule states at 6020 C: "*Beginning in 2020 and each calendar year thereafter, the CCR trigger price shall be 1.025 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent. The CCR trigger price in calendar year 2021 shall be $13.00. Each calendar year thereafter, the CCR*	These corrections have been made.

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	trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1A." The RGGI states note that the 2017 Model Rule modifies the CCR trigger price trajectory after 2020. The 2017 Model Rule states that the RGGI CCR will be $13.00 in 2021 and increase by 7% per year in the years following. To be compatible, RGGI states suggest the following: *"The CCR trigger price in calendar year 2020 shall be $10.77. The CCR trigger price in calendar year 2021 shall be $13.00. Each calendar year thereafter, the CCR trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1A."* Virginia's proposed rule displays a list of CCR trigger prices in Table 140-1A. These prices differ from those shown in the RGGI 2017 Model Rule by one cent, for the prices starting in 2024 and ending in 2030. Likewise, Virginia's proposed rule displays a list of ECR trigger prices in Table 140-1B. These prices differ from those shown in the 2017 Model Rule by one cent, for the years 2026, 2029, and 2030. Revised tables are provided.	
137-5. RGGI	The proposed rule states at 6020 C: *"'Conditional allowance' means an allowance allocated by the department to CO2 budget sources and to DMME. Such conditional allowance shall be consigned by the entity to whom it is allocated to the consignment auction…after which the conditional allowance becomes an allowance to be used for compliance purposes."* The RGGI states suggest a change to the final clause of this section, to clarify the relationship between a conditional allowance and a CO_2 allowance: "*…after which the conditional allowance becomes a CO_2 allowance once it is sold to an auction participant."* A similar issue exists in 6430, p. 959, where the proposed rule states: *"At the completion of the consignment auction, a conditional allowance shall become an allowance used for compliance purposes."* The RGGI states suggest a change to this language, to clarify the relationship between a conditional allowance and a CO_2 allowance: "*At the completion of the consignment auction, a conditional allowance sold at auction shall become a CO_2 allowance."*	The proposal has been revised accordingly.
137-6. RGGI	The proposed rule states at 6020 C: *"'Minimum reserve price' means, in calendar year 2020, $2.00."* The minimum reserve price for RGGI auctions in 2020 will be $2.32. The RGGI states recommend correcting this number in order to be compatible with the 2017 Model Rule.	The proposal has been revised accordingly.
137-7. RGGI	The proposed rule states at 6020 C: *" 'Receive' or 'receipt of' means, with regard to CO_2 allowances, the movement of CO_2 allowances by the department or its agent from one COATS account to another, for purposes of allocation, transfer, or deduction."* This definition should match the updated definition in the 2017 Model	The proposal has been revised accordingly.

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	Rule: *" 'Receive' or 'receipt of' means, when referring to the* [REGULATORY AGENCY] *or its agent, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the* [REGULATORY AGENCY] *or its agent in the regular course of business."*	
137-8. RGGI	The proposed rule states at 6020 C: *"'RGGI, Inc.' means the 501(c)(3) non-profit corporation created to support development and implementation of the Regional Greenhouse Gas Initiative (RGGI). Participating RGGI states use RGGI, Inc., as their agent to conduct the consignment auction, and operate and manage COATS."* The RGGI states recommend deleting the definition of RGGI, Inc., while retaining the general concept of an agent designated to conduct auctions and manage allowance tracking.	The proposal has been revised accordingly.
137-9. RGGI	The proposed rule states at 6020 C: *"'State' means the Commonwealth of Virginia. The term 'state' shall have its conventional meaning where such meaning is clear from the context."* In clarifying the "conventional meaning" of the word "State," the rule should also incorporate the broader 2017 Model Rule definition: "*A State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands."* Also, the RGGI states recommend that the broader term "State" not be used in the Virginia regulation where the more specific term "Participating State" would be more appropriate. Where the term "Participating State" is used in the 2017 Model Rule, this term should also be used in the Virginia regulation instead of "State." This would help avoid confusion and ensure compatibility.	The proposal has been revised to eliminate the definition of "state" altogether and rely instead on the definition of "participating state." "State" is a commonly understood term, and there is no need to define it in this regulation. "Participating state" is an important term of art, and is properly defined separately.
137-10. RGGI	The proposed rule states in 6200 A & B: "*A. The department may retire undistributed CO_2 allowances at the end of each control period. B. The department may retire unsold CO_2 allowances at the end of each control period."* Conditional allowances should not be allowed to be transferred, except to be sold at auction, retired, or withheld as part of an ECR trigger event. Accordingly, this phrase should reference undistributed and unsold "conditional allowances" instead of "CO_2 allowances": *"Undistributed or unsold conditional allowances shall not be transferred, with the exception of a transfer to consign them to auction, retire them, or withhold them in the event of an ECR trigger event. The department may retire undistributed conditional allowances at the end of each control period. B. The department may retire unsold conditional allowances at the end of each control period."* A similar issue exists in 6210 E, where the proposed rule states: "*The department will convert and transfer any*	The proposal has been revised accordingly.

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	CO2 allowances that have been withheld from any auction or auctions in the prior year into the Virginia ECR account…The department will withhold CO2 ECR allowances as follows." "Conditional allowances" should replace "CO_2 allowances." Also note that "in the prior year" has been removed from the 2017 Model Rule, and should be removed here: *"The department will convert and transfer any conditional allowances that have been withheld from any auction or auctions into the Virginia ECR withholding account…The department will withhold CO_2 ECR allowances as follows."*	
137-11. RGGI	The proposed rule states in 6210 I: *"Timing requirements for CO_2 allowance allocations shall be as follows. 1. By May 1, 2019, the department will submit to RGGI, Inc., the CO_2 conditional allowance allocations, in a format prescribed by RGGI, Inc., and in accordance with 9VAC5-140-6215 A and B, for the initial control period (2020). 2. By May 1, 2020, and May 1 of every third year thereafter, the department will submit to RGGI, Inc., the CO_2 allowance allocations, in a format prescribed by RGGI, Inc., for the applicable control period, and in accordance with 9VAC5-140-6215 A and B."* The RGGI states suggest removing references to RGGI, Inc. and replacing them with "its agent." This section should also replace "CO_2 conditional allowance" and "CO_2 allowance" with "conditional allowance": "*Timing requirements for CO_2 allowance allocations shall be as follows. 1. By May 1, 2019, the department will submit to its agent the conditional allowance allocations, in a format prescribed, and in accordance with 9VAC5-140-6215 A and B, for the initial control period (2020). 2. By May 1, 2020, and May 1 of every third year thereafter, the department will submit to its agent, the conditional allowance allocations, in a format prescribed, for the applicable control period, and in accordance with 9VAC5-140-6215 A and B."*	The proposal has been revised accordingly with some additional modification to improve clarity.
137-12. RGGI	The proposed rule states in 6020 C: *"'Fossil fuel-fired' means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 10% of the annual heat input on a Btu basis during any year."* This definition is inconsistent with and less stringent than the 2017 Model Rule, which sets a threshold of 5% of the annual heat input on a Btu basis during any year. The applicability provisions of the Virginia rule should be consistent and at least as stringent as those of the 2017 Model Rule. This change is necessary in order to ensure that Virginia's regulation is a corresponding CO_2 Budget Trading Program regulation, such that Virginia can be considered a RGGI Participating State.	The proposal has been revised accordingly.
137-13. RGGI	The proposed rule states in 6040 B, p. 938: *"Exempt from the requirements of this regulation is any fossil fuel power generating unit owned by an individual facility and located at that individual facility that generates electricity*	The proposal has been revised accordingly.

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	and heat from fossil fuel for the primary use of operation of the facility." This provision does not set a threshold for what constitutes "primary use of operation of the facility." In the 2017 Model Rule, facilities that provide less than 10% of their power output to the grid are exempted from compliance obligations. The RGGI states suggest that the Virginia rule consistently adopt this 10% threshold. The applicability provisions should be consistent and at least as stringent as those of the 2017 Model Rule. This is necessary in order to ensure that Virginia's regulation is a corresponding CO_2 Budget Trading Program regulation, such that Virginia can be considered a RGGI Participating State.	
137-14. RGGI	The proposed rule states in 6210 D 1: *"The department will initially allocate…CO_2 CCR allowances for calendar year 2020."* RGGI states suggest that Virginia clarify how the CCR provisions will work.	The proposal has been modified to specify that CCR allowances will be allocated on a pro rata basis to CO_2 budget sources.
137-15. RGGI	The proposed rule states in 6260 A: *"CO_2 allowances that meet the following criteria are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an interim control period."* This section mentions requirements for both a "control period" and an "interim control period." However, the Virginia proposed rule includes a third type of control period, the "initial control period." This "initial control period" includes only the year 2020, as a means of synchronizing with the RGGI states' compliance schedule. RGGI states suggest that the "initial control period" should also be mentioned here, to specify that compliance requirements apply in 2020: *"CO_2 allowances that meet the following criteria are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for an initial control period, a control period, or an interim control period."*	The proposal has been revised accordingly.
137-16. RGGI	The proposed rule states in 6430, p. 959: "*[C]onditional allowances shall be consigned by the CO2 budget source…or DMME to each auction on a quarterly pro rata basis in accordance with procedures specified by the department."* The RGGI states understand the "quarterly pro rata basis" to mean that generators must consign one quarter of their yearly total of conditional allowances at each auction, rather than distributing the consigned amount over the quarterly auctions at their own discretion. RGGI states suggest that this language be made more explicit in the Virginia rule: "*One quarter of the annual conditional allowance allocation shall be consigned by the CO_2 budget source…or the holder(s) of a public contract with DMME to each auction in accordance with procedures specified by the department."*	The proposal has been revised accordingly.
138. Richard Ball	A baseline as high as 33 or 34 MMT of CO_2, as proposed, would be much too high and lead to much less	Support for the proposal and the commenter's

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	reduction in Virginia CO_2 emissions by 2030 than is feasible and desirable. For example, the ICF/DEQ Policy scenarios show very low reductions in CO_2 emission reductions. Emissions have already been coming down since 2016 and most projections indicate that a trend in that direction is likely to continue in that direction even in the absence of the proposed regulation. I offer several lines of evidence for that, including calculations of actual 2017 emissions in Virginia for overall electric power emissions and emissions specifically from likely EGUs covered by the regulation. If the baseline is set in the range of 30-34 MMT of CO_2, the program might fail to achieve CO_2 reductions that are substantially greater than what would happen even in the absence of the ED 11 program. My conclusion is that it would be feasible to achieve reductions under a base cap of 28 MMT with an aggressive, but feasible solar or wind expansion program and phasing out a substantial amount of higher ED 11 CO_2 carbon sources along with considerable natural gas generation while maintaining a steady level of total Virginia generation. It also implies that it makes little sense to continue expanding natural gas generating sources since they are likely to be constrained in their generation. A steady level of generation would be consistent with an aggressive program of energy efficiency measures, which might be implemented as a result of new legislation enacted in the 2018 session of the General Assembly. RGGI expects Virginia to reduce its baseline cap, although they did not specify a particular value. In my analysis, I have borrowed results on the likely list of ED 11 EGUs that will be covered under ED 11 and the associated estimated generation, and CO_2 emissions from the comments submitted by the Virginia Chapter of the Sierra Club. Another conclusion is that the ICF modeling results published by DEQ in the autumn contained some out-of date assumptions due to subsequent events. I conclude that: the ICF results were furnished in autumn, 2017 before actual 2017 results for Virginia were known and before SB 966 was passed in the 2018 Session of the General Assembly, and before the announcement of retirement plans for a number of EGUs, so those factors could not be reflected in the modeling. In particular, CO_2 emissions by 2020 EGU-covered units in 2017 was overestimated in the ICF modeling as 32 MMT CO_2 , compared with the Sierra Club's estimate of 29 million tons based on actual 2016 data. Those factors also may have led to overestimation of subsequent modeled results for 2020 through 2030. Hence I look at likely emission reductions for other baseline cap values than just 33 MMT under several different policy assumptions.	observations on the base cap are appreciated. As discussed in the response to comment 37, the base cap has been set at 28 million tons.
139. Southern	DEQ has broad legal authority to promulgate regulations	Support for the proposal is

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Environmental Law Center (SELC)	to reduce CO_2 pollution through an emissions trading program. Specifically, the board is authorized to regulate air emissions, which includes CO_2. The Virginia Code authorizes the Air Board to "develop a comprehensive program for the . . . abatement and control of all sources of air pollution in the Commonwealth." This power includes the ability to "promulgate regulations . . . abating, controlling and prohibiting air pollution[.]" The law defines "air pollution" as "the presence in the outdoor atmosphere of one of more substances which are or may be harmful or injurious to human health, welfare or safety, to animal or plant life, or to property, or which unreasonably interfere with the enjoyment by the people of life or property." CO_2 clearly qualifies as a "pollutant" subject to board regulation. Indeed, it is well settled on a national level that CO_2 is a pollutant needing regulation. The Supreme Court held in Massachusetts v. EPA that GHG, including CO_2, are "without a doubt" pollutants under the Clean Air Act. Subsequently, EPA determined that GHG emissions endanger the public health and welfare. Virginia Code requires the board to “make . . . such investigations and inspection and do such other things as are reasonably necessary to carry out the provisions of this chapter . . . including the achievement and maintenance of such levels of air quality as will protect human health, welfare and safety[.]" At the state level, carbon pollution is a clear threat to Virginian’s health, welfare and safety. Virginia's coast faces the highest level of sea level rise on the Atlantic Coast of the U.S. Sea level rise is also a threat to public and private property, including the Norfolk Naval Base and the Hampton Roads region, which is becoming increasingly vulnerable to flooding. A report issued by the Virginia Institute of Marine Science predicts sea level rise will increase in the Hampton Roads area by more than a foot between 2018-50. Moreover, in Virginia, climate change is exacerbating chronic respiratory diseases. Because of the clear danger carbon emissions pose to human health, welfare and safety, it is well within the board’s broad legal authority to regulate these harmful pollutants. Linking to RGGI preserves Virginia’s autonomy, while addressing the threat carbon emissions pose to the state in a cost-efficient manner.	appreciated. As discussed here and, for example, the response to comment 76, the board clearly has the authority to address demonstrated negative GHG effects in accordance with its mandate to protect public health and welfare.
140. SELC	Covering new and existing fossil fuel-fired units prevents a market perversion where power generators could shift generation away from regulated plants to new, unregulated power plants, which would not produce a reduction in statewide carbon emissions. We are also glad to see that the regulation applies to all CO_2 emitted from co-firing units that include at least one fossil fuel-fired unit. However, the final regulation should include all electric power facilities that emit CO_2, regardless of fuel type. Specifically, the regulation should apply to any 25 MW unit that burns biomass.	See the response to comment 67 for detailed discussion of how biomass will be treated.

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	The science is clear that burning certain biomass, particularly forest-derived biomass, increases net atmospheric CO_2 for 35-100 years or more, compared to fossil fuels. Numerous studies have shown that burning chips or pellets made from standing trees puts more CO_2 in the atmosphere than continuing to burn coal in existing or new power plants. One report showed the use of whole trees from naturally regenerated forest in the U.S. for power production could result in four times the amount of carbon in the atmosphere versus burning coal over a 100-year timeframe. Thus, it is critical that the regulation cover all net carbon emissions. Straightforward carbon accounting protocols such as those advocated by the Partnership for Policy Integrity (PFPI) demonstrate that even under the best case scenario, emissions from wood-burning plants exceed those from fossil fuel-fired plants for periods of one to two decades and beyond. As a result it is most reasonable to include all biomass stack emissions under the cap. Should DEQ wish to provide some credit to generators who are burning true wastes or residues, PFPI has offered a calculator that can be used to find the net emissions over the regulatory time frame. This framework would appropriately weight emissions from industrial facilities burning black liquor as having nearly zero net emissions, as the framework assumes that black liquor would be burned for disposal even if energy recovery does not occur. It would also reflect the net impact of burning wood residues more accurately than the current effective assumption that emissions are zero, when biomass facilities are not covered under the cap. DEQ should amend the regulation to include "any unit combusting carbon-based fuels that serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe . . . and any sources that includes one or more such units shall be a CO_2 budget sources, subject to the requirements" of the regulation.	
141. SELC	SELC supports a 33 million ton base budget and 3% reductions annually thereafter, but encourages DEQ to consider actual emissions data from 2019 to determine whether the 2020 cap should be revised down. Contrary to concerns raised in comments to the NOIRA, compliance with Version 1 is in fact readily achievable. Dominion's 2017 IRP created a Plan Alternative for Clean Power Plan compliance which readily met the Virginia limit of 27,830,174 tons of CO_2 by 2030. Version 1 of the regulation requires 23.10 million ton cap by 2030. However statewide carbon emissions in 2017 were 31.2 million tons, which are lower than the Version 1 baseline of 33 million tons. Also note that SB966, passed by the General Assembly in 2018, proposes 5,000 MW	As discussed in the response to comment 37, a cap of 28 million tons has been set. The regulation has been amended to specify that the department will review the base budget and recommend appropriate adjustments in the base budget for 2031 and succeeding years, considering the best

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	of renewable, carbon-free generation and over $1 billion in energy efficiency investment between now and 2028. With this new landscape, we encourage further modeling to predict what 2018 and 2019 emissions are likely to be and recommend a starting baseline that is the lower of Version 1 or DEQ's updated forecast for actual 2019 carbon emissions. This allows DEQ to avoid setting a baseline cap that is higher than actual emissions in the first compliance year. A lower initial base budget and more stringent overall cap by 2030 also better achieves the goal of reducing CO_2 emissions, growing Virginia's clean energy economy, and protecting the public health and welfare. We support the decision to implement a 3.0% per year reduction in carbon emissions over 10 years beginning in 2020. This results in a base budget of 23.10 million tons by 2030. While this is a good initial reduction and sensible 10-year goal, SELC encourages a 10 year review provision. This 10-year review provision would ensure that Virginia continues to reduce its carbon emissions beyond the initial 10-year goal and determine emissions reduction goals beyond 2030.	available science and all relevant information and policies available from any CO_2 multi-state trading program in which Virginia is participating. In the context of the RGGI program as a whole, it is important to remember that the program is subject to routine program review. As discussed elsewhere, the RGGI states routinely review and evaluate how current strategies are working, and look ahead to what changes are needed to the program to insure its ongoing effectiveness. RGGI's comprehensive program reviews will consider program successes, impacts, and design elements. As part of this process, DEQ will evaluate where Virginia needs to go with respect to budgets and allowances. In order to be transparent and effective, this must be effected through the program review process in concert with the other RGGI states.
142. SELC	SELC supports the 5% set aside to assist DMME in efforts to abate and control air pollution, although we encourage DEQ to evaluate whether a 10% set aside would produce more benefits than it would increase costs for covered entities. SB966's commitment to energy efficiency is a notable improvement on the role efficiency will play in Virginia's energy future, but there can always be better and more diverse initiatives to bring this lowest-cost resource to Virginia. Despite being the lowest-cost energy resource, energy efficiency measures are also among the most labor-intensive, which means that the effect of every dollar spent on efficient has greater economic ramifications that dollars spent on more traditional, supply-side energy resources. A recent study by Applied Economic Clinic of Virginia's possible energy efficiency future found that under a "medium efficiency" scenario, total annual electricity sales in Dominion's territory could actually decrease. As Virginia's in-state generation fleet becomes less carbon intensive as a product of SB966, a decrease in total	Support for the proposal is appreciated. As discussed in comments 51 and 83, a relatively small 5% set-aside is appropriate in the early stages of the program, although this amount may be revisited as a result of program review.

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	energy sales only amplifies the possible reduction in statewide carbon emissions. The study also confirmed that a "medium efficiency" scenario could lower customer bills by up to 0.3% by 2028. The 5% (or possible 10%) set aside can play a key role in helping Virginians achieve lower carbon pollution and lower electricity bills.	
143. SELC	The proposal includes several important cost management mechanisms, similar to those provided for in the RGGI program. SELC supports the inclusion of these provisions as they are designed to provide enhanced market flexibility and stability, and have proven to be important in establishing a successful cap-and-trade program. Consistent with the RGGI program, the regulation allows covered entities to bank unlimited CO_2 allowances. SELC supports this provision, so long as it is clear banking can occur for allowances purchased at auction. Banking provides flexibility and has been shown to encourage sources to reduce their emissions sooner and below required levels. Banking ensures that all CO_2 reductions have a long-term economic value, and not merely short-term value for immediate compliance purposes. By using banking, participants are very adept at smoothing the supply of allowances over time--for example, banking allowances in early compliance periods in anticipation of increased allowance scarcity in later periods. Research on other cap-and-trade programs without banking indicates that such programs typically result in "just-in-time" emission reductions, rather than encouraging cost-effective, long-term emissions reductions. The budget adjustment for banked allowances is necessary due to the high volume of allowances banked during early compliance periods where the volume of RGGI allowances far exceeded actual emissions. Although the RGGI states significantly lowered the regional cap to more closely reflect actual emissions, participants had already banked large numbers of allowances. In 2014, for example, there were an estimated 140 million tons of banked allowances, significantly exceeding that year's emission cap of 91 million tons. Even with the significant cap reduction in 2014, emission reductions were unlikely to occur without further adjustment to account for the volume of banked allowances. These adjustments have been in place for several compliance periods, with the third such adjustment period applying to allocation years 2021-25. Virginia sensibly includes this adjustment, which should further the goal of reducing CO_2 emissions in an economically efficient manner. SELC supports the CCR allocation, although improvements should be considered in the coming years to ensure that such reserves are only triggered during truly unexpected price spikes. In the event the allowance	DEQ agrees that RGGI's cost management mechanisms will ensure that the emissions cap is maintained while managing prices and assuring a stable market.

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	price exceeds a specified price ("trigger price"), the CCR mechanism introduces a limited quantity of additional allowances into the auction to increase the supply and thereby reduce the cost. After being implemented in 2014, the CCRs have already been triggered twice, which raised concerns that the containment mechanism is not functioning as intended. Instead of being reserved for truly extreme and unexpected market spikes, the CCR trigger prices may have been set too close to anticipated allowance prices, resulting in 15 million reserve allowances being added to the market. Some have argued that these additional allowances were unnecessary, given the large quantities of banked allowances. In 2017, after another design review, RGGI implemented several changes to the CCR mechanism, which should help prevent unnecessary allowances from being released into the market. For example, the trigger price was initially set at $4 in 2014 raising to $10 in 2017, and thereafter escalating by only 2.5% each year. Now the trigger price will be set a $13.00 in 2021 and increase by 7% every year. Additional changes to the CCR mechanism should be considered. Most importantly, the proposal, consistent with the RGGI program, provides that every year, additional allowances--up to 10% of the emissions cap--can be allocated and sold at auction in the event of a trigger. While this mechanism should help to contain cost, it also effectively increases the overall cap. Virginia, along with other participants in the RGGI auction process, should consider whether additional modifications could better balance carbon emission reduction with cost concerns. For example, it may be more effective to generate CCRs by borrowing allowances against future years or from allowances unsold at auction, rather than generating additional allowances. This sort of program-level borrowing would maintain the overall emissions cap across the initial 10 year program, while still protecting against short-term price spikes. SELC also supports the ECR. There is inherent price uncertainty in a market-based cap-and-trade program due to factors such as natural gas price volatility, variable electricity demand, uncertainties associated with nuclear projects, and evolving renewable energy programs. Where prices are significantly higher than anticipated, the CCR is designed to increase supply and reduce cost. Prior to 2017 changes, however, there was not an analogous mechanism if prices were lower than anticipated. Instead, the RGGI program relied only on a reserve price--a minimum acceptable bid. In 2017, the RGGI program changed its model rule to incorporate an ECR, which Virginia has incorporated into the regulation. In the event allowance prices fall below established triggers, Virginia, like other RGGI states, will withhold up to 10% of its allowances from circulation. According to	

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	the RGGI model rule, the ECR trigger price is set at $6.00 in 2021 and will rise at 7% each year. This cost management mechanism should help further Virginia's overall policy goal of reducing carbon emissions in the event that emission reduction costs are lower than projected. Initial modeling of this mechanism indicates that it should further incentivize carbon emission reductions. In situations of low demand and low prices, i.e., situations where the emissions containment reserve is likely to be triggered, a cap-and-trade program is typically not driving emission reductions. Modeling of the emission containment reserve should better align incentives for individual actors in the region and make the auction price more responsive to supply.	
144. SELC	SELC supports the 3-year review, updating output-based allowance allocation method. This method of allocating allowances based on a rolling average of emissions over the past 3 years ensures that where generators do not use the full amount of allowances received over 3 years, these allowances can be retired or banked, and not hoarded by the generator. To the extent any parties express concern about leakage, we believe DEQ has adequately addressed that issue with its continually-updating output system. In any event, emissions leakage is not likely to become an issue. Some critics have argued leakage would occur in RGGI states, yet studies have found that these concerns have not materialized. Indeed, RGGI's most recent Monitoring Report found no evidence of significant leakage. Moreover, Dominion Energy's 2017 IRP demonstrated Clean Power Plan compliance was possible without significant increases in purchased power. While Plan CT is not an exact match to the proposed trading program, it demonstrates Dominion's ability to comply with a significant carbon emissions reduction program without resulting in emissions leakage. Thus, while leakage is unlikely to become an issue under the proposed system of emissions reduction, the allocation method used in the proposal should address concerns raised by those who fear leakage to be an issue with cap and trade systems.	DEQ agrees that the 3-year review, updating output-based allowance allocation method will best control allowance distribution while avoiding potential leakage.
145. SELC	The regulation should ensure the program is the most economically advantageous for customers and families. While we support banking of allowances, we only support banking of allowances that a unit has purchased in the market, not banking of allowances received at no cost from DEQ and not submitted to the RGGI auction. Article 9 must make clear that all generators are required to sell all allowances back into the consignment auction. Without a full-market participation requirement, a generator could hoard a large share of CO_2 allowances in order to influence prices or prevent competitors from obtaining allowances. To ensure this anti-competitive behavior does not occur, the regulation must ensure 100% of conditional allowances make it to the consignment auction. While the system appears	The commenter's concerns are appreciated. The definition of "conditional allowance" has been amended to specific that a conditional allowance becomes a CO_2 allowance once it has been sold to an auction participant. The RGGI states suggested this change to clarify the relationship between a conditional allowance and a CO_2 allowance. DEQ agrees that collaboration

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	designed in such a way, additional language could help clarify this important point. Generators initially receive conditional allowances for free, prior to selling into and buying back from the consignment auction. Systems with free allowances have commonly led to windfall profits for generators, to the detriment of customers. However, free allocation systems can be done in a way that prioritizes customers. The final regulation should include a review mechanism to prevent these windfalls for generators and ensure that customers benefit. One means to achieve this is through SCC review of how these windfall profits are used. Indeed there are a number of ways that customers could benefit from allowance profits, whether directly through rate credits, or indirectly through greater emissions reductions, investments in energy efficiency, or other reductions in compliance costs. SELC urges the board to collaborate with the SCC in its review of how generators use windfall profits in order to achieve the greatest level of carbon emissions reduction in the most economically advantageous way for customers. For instance, one possible windfall could occur where a generator sells more allowances in RGGI than it buys back for its own compliance, making it a net seller. In that scenario, the generator is revenue positive as a result of the trading program, but DEQ will have information regarding how many allowances that utility received, how many it surrendered in compliance, and what the various market prices were, which DEQ could make public and also provide to the SCC as it reviews utility earnings and expenses in upcoming triennial rate cases and annual fuel factor dockets. DEQ should also include some failsafe mechanism to ensure that the generator does not profit from the trading program at customer expense as a result of inadequate SCC oversight.	with the SCC is an important element of ensuring that the carbon trading program operates properly in the context of SCC responsibilities
146. Virginia Chapter of the Sierra Club, Appalachian Voices; Virginia Interfaith Power and Light; Environment Virginia; Chesapeake Climate Action Network.	Virginia's proposal to develop a CO_2 trading program that links to the existing RGGI program is an appropriate mechanism to begin reducing CO_2 emissions in Virginia. Although improvements should be made, we support action to limit and reduce CO_2 emissions from power plants and to link to RGGI's larger market. The proposal's goal of reducing CO_2 by 30% from 2020-30, at an annual rate equal to 3% of the base year allowances, is modest and can readily be achieved as demonstrated by planned actions that will reduce emissions and by actual experience in the RGGI states. Importantly, the proposal intends to achieve actual CO_2 reductions, not reductions in carbon intensity which can disguise emissions increases as decreases in the rate of emissions-per-MWH of generation. Dangerous climate change is driven by actual CO_2 emissions and atmospheric CO_2 levels, not the intensity of emissions. While Virginia could potentially implement CO_2 reduction	Support for the proposal is appreciated. DEQ agrees that linking to RGGI will benefit the Commonwealth by protecting public health and welfare in a fiscally responsible way.

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	requirements without tradable emissions allowances, linking Virginia's proposed plan to RGGI is a good choice. Through 2016, RGGI states had reduced CO_2 emissions from covered power plants by 40% from 2008. RGGI reduced CO_2 emissions at faster rates and with lower costs and greater benefits than predicted. Moreover, those emissions reductions were achieved while customer bills were reduced and while the economies of participating states grew. Reductions in air pollution in RGGI states have improved health outcomes. RGGI's program has been so successful that its member states recently agreed to build upon CO_2 reductions already achieved, so that covered sources reduce CO_2 by an additional 3% per year for 10 years between 2020-30, achieving an overall reduction of more than 65% compared to its initial 2009 cap. Joining this established CO_2 market will help Virginia reduce CO_2 smoothly and cost-effectively, and would avoid the potential pitfalls from implementing a Virginia-only market. The market for allowance trading will enable power plant operators to buy or sell allowances as appropriate to their individual circumstances, while aggregate CO_2 emissions decline. Since RGGI is both very successful and the only functioning CO_2 market in the eastern U.S., it would make no sense to go it alone. Under a consignment auction approach, the value of allowances will go to covered power generators, and utilities will be able to use the funds, subject to regulatory oversight, to reduce electricity rates and to support incremental investments in zero-carbon energy sources and energy efficiency. Such zero-carbon energy investments will further mitigate electric energy costs by reducing fuel purchase requirements. In its 2017 IRP proceeding, Dominion acknowledged that solar costs have fallen dramatically and that solar is now the cheapest form of energy. Both utility and non-utility generators should be required or encouraged to invest such funds in renewable energy and energy efficiency, or, at minimum, to pass consignment revenues through to retail customers. The allocations of conditional allowances can be reconsidered if consignment revenues are not used to advance the rule’s goals. The emission reductions contemplated by ED11 are readily achievable. RGGI's market began full operation in 2009. By 2012-14, the average annual CO_2 emissions from the 2009 baseline had been reduced by 35.7%; and annual emissions in 2016 were 40% below those in 2008. Those reductions occurred in far less than 10 years, and RGGI reduced caps to reflect the more rapid progress. RGGI is now planning to reduce its CO_2 cap by an additional 3%/year from 2021-30, thereby achieving a 65% reduction from its initial 2009 allowance cap. Significantly, AEP recently announced its voluntary	

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	commitment to reduce its CO_2 emissions from power production by 60% from 2000 levels by 2030 and by 80% by 2050. Its planned CO_2 reductions will be achieved through increased reliance on wind and solar energy, retirements of coal-fired plants, natural gas, greater energy efficiency and grid modernization, and the reductions are to be achieved even as electric demands may increase with greater electrification of the economy. Although AEP's planned reductions fall short of what will ultimately be needed to adequately mitigate global warming, they nevertheless illustrate that willing electric utilities can substantially reduce CO_2 emissions, consistent with customer and shareholder interests. AEP explains that its new clean energy strategy is driven by investors, business risks and the known need to reduce CO_2 in order to limit the global average temperature rise to less than 2°C. In short, the proposal is modest, achievable and reflects the unquestionable need to shift to clean energy as soon as practicable.	
147. Virginia Chapter of the Sierra Club et al.	The mix of generation and emissions is changing rapidly and will change more by 2020. The proposed initial aggregate cap of 33-34 million tons for 2020 is too high and out of date. A too-high initial cap will distort RGGI's markets by artificially inflating the pool of allowances. It would fail to produce real reductions in CO_2 and could lead to higher emissions. The 2020 cap should be set below 30 million tons, subject to updating the 2020 level in a proceeding to be held in early 2019. Updating the 2020 baseline based on the latest available information would be fair to the public and all parties. At the same time, setting a cap below 30 million tons would reflect the most current information and would give better planning notice to owners of budget sources than overstated estimates of 33-34 million tons. However, if the baseline is set at 33-34 million tons, then the annual rate of reductions should be increased to 3.5% per year, which would still be slower than RGGI's average annual reduction over its first 10 years. Changes in the fuel mix are occurring now and more changes are expected. The 2020 baseline should take into account all planned fossil fuel retirements and deactivations between now and 2020. It should also recognize that approved new natural gas facilities will displace emissions from coal plants that remain open. Between 2016-17, natural gas use in Virginia's electric power sector rose, while coal-combustion fell and retail sales fell. From 2016-17, the capacity factors of two of Virginia's largest coal-fired plants dropped by over 40%, and the CO_2 emissions just from those plants dropped by 4,989,186 tons, from 11,783,154 in 2016 to 6,793,968 tons in 2017. Recent additions of natural gas-fired generation have occurred and more are expected; they will continue to push out dirtier coal-fired plants. Traditional coal plants emit roughly 2.75 times as much	A base cap of 28 million tons has been selected; see the response to comment 37 for more information.

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	CO_2 per MWH than new combined cycle plants, so the trend is toward a much lower CO_2 baseline in 2020. We estimate that the addition of the Greensville plant could displace 7 million tons of CO_2 from coal plants even at a modest 70% capacity factor. Beyond 2017, a number of retirements are expected. In its 2017 IRP, Dominion discussed potential fossil fuel plant retirements. On January 16, 2018, Dominion announced a number of retirements by filing with PJM deactivation requests for 9 fossil fuel units. Collectively, these units have a combined nameplate capacity of over 1,700 MW and emitted around 2.4 million tons of CO_2 in 2016, or 7% of the state's reported power emissions. In addition, Dominion announced the planned retirement of Yorktown 1 & 2. The Spruance and Edgecombe Genco plants have also notified PJM of their intent to retire in 2019 and 2020. Combined, this merchant capacity reflects another 300 MW of capacity and 1 million tons of annual CO_2 emissions. These announced retirements (which would account for 3.4 million tons of CO_2) and any other planned retirements or cold storage of units should be incorporated into calculation of the 2020 baseline. We looked at data for units that operated in 2016-17 and are not scheduled for retirement, and found that 2017 CO_2 emissions from covered fossil-fuel units that will still be operating in 2020 were approximately 29 million tons and the trend was downward, particularly for coal-fired units. The 2020 baseline should incorporate planned renewable energy developments through 2020. Energy from utility scale solar and wind is cheaper than from fossil fuels, and many customers are willing to provide the capital for small-scale solar. The estimates should reflect the improved prospects for renewables, which were boosted by recent legislation as well as by the low cost of solar and wind generation. According to the 2017 Virginia Solar Energy Development and Energy Storage Authority Annual Report, there are presently 219 MW of solar installed and an additional 2,703 MW under development. The PJM queue identifies 8 solar projects with a combined nameplate capacity of 717 MW with projected in-service dates between 2018-20 that would interconnect in Virginia. It is likely that additional solar will be added through 2020 as a result of third-party investments or arrangements with utilities, such as the agreement between Dominion and Amazon to install solar. Recent legislation calls for approximately 5.5 GW of solar generation by 2028. These developments must be accounted for in developing the baseline. Since Dominion serves an integrated system in Virginia and North Carolina, the 2020 cap should also take into account solar connected to Dominion's system in North Carolina which will tend to reduce Dominion's need to	

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	generate energy in Virginia. Dominion has emphasized the growing electric demand for data centers. However, such loads are specifically asking for renewable energy. Those loads will add more to zero-carbon generation than to fossil fuel generation. A group of data companies submitted a September 2017 letter to the SCC in Dominion's IRP docket. They asked regulators to take energy resource preferences into account when deciding on future energy infrastructure projects to meet energy load growth from data centers. Citing economic, environmental and market needs, they explained why they wanted more renewable energy and why the IRP under-deploys renewable energy. Thus, demands for solar energy will limit future CO_2 increases even if load grows. This should be considered in setting a baseline below 30 million tons. Electric loads have flattened in recent years. Virginia's retail electricity usage declined between 2016-17. To the extent DEQ's analysis of the 2020 cap relies on Dominion's load forecasts, it should step back. Dominion's forecasts of load growth have been consistently overstated. Virginia's baseline should also account for the state's untapped energy efficiency potential and reflect savings that can be achieved by 2020 and beyond. Electricity generators should not get a higher CO_2 cap for 2020 because Virginia's utilities failed to meet the goal for efficiency-driven demand reductions of 10% compared to 2006 demand. Virginia should not reward its utilities with a higher baseline for CO_2 emissions, which would elevate emissions caps for at least a decade, based upon an indifferent approach to efficiency.	
148. Virginia Chapter of the Sierra Club et al.	We strongly support the proposed definition of "fossil fuel-fired" which would cover most co-firing of biomass and fossil fuels. However, the requirement to purchase CO_2 allowances should be extended to cover all biomass generation meeting the otherwise applicable size requirements. The requirement to purchase allowances should extend to new and existing biomass-fueled units, particularly those that burn wood-based biomass, which is the least likely to result in CO_2 recapture within a time frame helpful to avoiding the looming climate crisis. The premise for exempting generators that burn biomass is that the emitted CO_2 will eventually be recaptured by regrowth of the feedstock and that is sufficient to mitigate the climate damages from current CO_2 emissions. Those assumptions are faulty in several respects. Biomass burns less efficiently than coal or natural gas so more biomass must be burned to produce each MWH of electricity, resulting in CO_2 emissions that are substantially higher than from coal and natural gas. Co-pollutants from biomass combustion are large and	The commenters' concerns about biomass are recognized; see the response to comment 67 for more information.

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	harmful to human health. Gradual deterioration of wood residues occurs over many years, but the net CO_2 emissions impacts from burning even residues remain large. Adverse climate and health impacts from burning biomass will not be offset by resequestration of CO_2 in the future, even assuming that the biomass is replaced with comparable forests. Exempting biomass from carbon prices would undercut beneficial investments in zero-carbon alternatives, which mitigate climate harms in the near- and long-term. There is no support for the assumption that forests will be regrown in a sustainable way or in sufficient quantities to recapture that CO_2. Furthermore, past investments in large biomass facilities do not deserve special treatment any more than past investments in fossil fuel-fired facilities. The public and climate are harmed by CO_2 emissions in both cases. The climate crisis will never be resolved if previously built emitters are granted exemptions. In any event, value of allowance auction revenues can be passed through to customers to mitigate cost impacts.	
149. Virginia Chapter of the Sierra Club et al.	The rule should be amended to require continued annual reductions of the CO_2 cap beyond 2030, at the same annual quantities as from 2021-30, until the rule is modified. This could be achieved by altering 9VAC5-140-6190 C to state: "For 2031 and each succeeding calendar year, the Virginia CO_2 Budget Trading Program base budget will be reduced by the same annual quantity as the reduction between 2029 and 2030." Continuing to reduce CO_2 at the same annual rate would mean a reduction of approximately 1 MM tons/year, which would achieve a 90+% reduction by 2050. The key is to clearly indicate that reductions will continue until climate stabilization is achieved. If a specific post-2030 target is desired then the rule could provide that yearly reductions of the annual cap will continue, for example, either until the emissions cap on covered sources has been reduced by 90% from the 2020 base budget or until the emissions cap on covered sources has been reduced by the same percentage as has been achieved by RGGI member states relative to their pre-auction emissions. Since RGGI's announced 2030 reduction target is more than 65% below its 2009 cap the latter measure would continue reductions until at least that percentage of emissions reduction is achieved in Virginia--or until greater reductions are achieved if RGGI extends its annual reductions beyond 2030. This would assure that Virginia eventually catches up with a level of reductions that RGGI has shown are achievable. At minimum, it is necessary to clarify that the emissions trajectory post-2030 will be at least as stringent as that agreed to by the RGGI states in subsequent program reviews for the post-2030 years. Absent emission reductions that continue to at minimum match the stringent of the RGGI program beyond 2030, Virginia would be unable to continue to link its program with the RGGI states and reap the benefits of	The proposal has been amended to clarify that CO_2 reductions will indeed continue to be required after 2030; see the response to comment 141.

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	the larger carbon market.	
150. Virginia Chapter of the Sierra Club et al.	Climate change disproportionately harms the poor and other disadvantaged communities. Residents near and downwind of fossil-fuel power plants suffer disproportionate health impacts from co-pollutants such as particulates, SO_2, ozone, and mercury, and are disproportionately low-income or minority. Generating electricity with biomass also produces high levels of harmful air pollution. In contrast, solar, wind and efficiency do not produce any carbon pollution or co-pollutants. Over half a million people in Virginia live within three miles of a power plant that was to be covered by the Clean Power Plan. Of these, 52% are minority and 34% are low-income, while Virginia has a total minority population of 35% and low-income population of 26%. According to the U.S. Office of Minority Health, black people are three times more likely to die from asthma-related causes than white people. Capping and steadily reducing aggregate CO_2 emissions and co-pollutants will generally improve health outcomes in Virginia and benefit all communities, including disadvantaged communities. This positive benefit from reducing CO_2 has been documented in RGGI states, which have experienced improvements in health outcomes since RGGI's carbon limits took effect. RGGI states have also seen dramatic reductions in SO_2. It is possible that trading could allow some fossil fuel plants to use allowances to continue or increase polluting operations. As a result, localized harms may occur even if the rule produces overall progress. It is therefore critical that DEQ commit to conduct EJ and emissions studies; to continuously monitor and report concentrations of CO_2 and non-CO_2-pollutants to ensure that disproportionate concentrations do not harm particular communities or regions; to investigate detected concentrations as well as any complaints of disproportionate local impacts and to pursue appropriate remedial actions. We urge DEQ to consider amending the rule to prohibit plants fired with coal, biomass or heavy oil from acquiring allowances to increase their annual emissions over historic levels without first obtaining a permit.	DEQ agrees that disadvantaged communities must be specifically addressed in the context of wider EJ programs at the state level and has amended the proposal accordingly; see the response to comment 55.
151. Virginia Chapter of the Sierra Club et al.	The proposal to cover existing units serving a generator of 25 MWe or larger is generally consistent with RGGI's existing rule. However, the rule should be amended to state that the 25 MWe threshold only needs to be crossed once to trigger coverage by the rule. This is important so that coverage cannot be avoided through manipulation of a unit's size or configuration. 9VAC5-140-6040 A should be modified to state that the rule covers units serving all generators having a nameplate capacity of 25 MWe or more "at any time on or after" a fixed date. To be consistent with RGGI's model rule, it would be reasonable to adopt January 1, 2005 as the on-	The applicability limit is indeed designed to be consistent with the RGGI Model Rule. Current state regulation (9VAC5-20-70) prohibits circumvention of air quality requirements by constructing multiple facilities in a piecemeal fashion in order to avoid regulation. DEQ believes that the declining emissions

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	or-after date. Alternatively, the on-or-after date could be shortly prior to the first notice that a plant might be covered by CO_2 regulations. The rule should be modified to require new units serving generators with a nameplate capacity less than 25 MWe to obtain emissions allowances. We suggest the threshold for new generators be set at 15 MWe or less. This is needed in order to send CO_2 regulatory and price signals to a broader pool of new generators and to prevent gaming that would undermine the regulation's CO_2 reduction goals and that would be unfair to existing generators. Within the RGGI region, there are recent proposals for multiple generation fossil fuel-fired units each just below the 25 MWe compliance threshold. Since economic efficiencies and operating efficiencies would ordinarily support larger units, the sizing appears to be driven by a desire to emit CO_2 without limits, thereby undercutting public health and the goals of the regulation. Since it is essential to reduce future emissions, there is no reason to encourage new generation that emits CO_2. With coverage of new units, the rule would better protect the public from CO_2 and co-pollutants, remove an incentive for building less efficient fossil fuel generators, and protect the integrity of allowance markets. Since developers would have notice of the allowance requirement for new generation, no unfairness would result from imposing a lower size threshold for such generation. Units placed in service after January 1, 2019 would fairly be considered new.	cap will encourage the development of renewable energy and energy efficiency, not the construction of multiple smaller facilities which, as the commenter points out, are less efficient.
152. Virginia Chapter of the Sierra Club et al.	Allocations of conditional allowances is a pragmatic choice designed to implement tradable emissions allowances. However, recipients of economically-valuable conditional allowances should be encouraged to use that value to promote the carbon-reduction purposes of the rule, not to produce windfalls. The proposal presumes that utilities will utilize revenues received from the consignment-and-auction process for the benefit of customers, either through incremental investments in energy efficiency or zero-carbon generation or applying the revenues to reduce retail rates. While this seems to be a reasonable assumption in light of SCC regulation of utilities, it is not a guarantee. DEQ should monitor how the auction revenues are utilized and consider adjusting the method for allocating allowances if the revenues are not used to advance the purposes of the rule. Recipients of allowances should be required to report annually how the auction revenue funds were used, including whether they were passed through to retail customers, used to reduce CO_2 emissions, used for other corporate purposes, or retained as earnings. Generators in other RGGI states do not expect funding from the auctions, and Virginia companies should not get auction revenues unless they promote the purposes of the rule.	The commenter correctly asserts that the SCC regulates and monitors utilities in order to assure that customers are protected. It is unclear how additional reporting requirements would ensure that these goals are effected.
153. Virginia	We support consigning a portion of the conditional	As discussed in comments

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Chapter of the Sierra Club et al.	allowances to holders of public contracts with DMME for the abatement and control of CO_2. RGGI member states use a much larger share of their auction revenues for such purposes by supporting measures to increase energy efficiency or zero-carbon renewable energy within their borders. It is reasonable for Virginia to do so with at least part of the revenues from the consignment auction process. Nevertheless, 5% is a small starting point. Consideration should be given to reallocating conditional allowances from non-utility generators or utilities to public contractors for implementing energy efficiency and renewable energy, particularly if the covered generators do not invest their auction revenues to expand zero-carbon energy solutions in Virginia.	51 and 53, a 5% set-aside is a reasonable figure in the early stages of the program.
154. Virginia Chapter of the Sierra Club et al.	Dominion's Mt. Storm is a large coal-fired electric generating facility located in West Virginia that is included in Virginia retail rates and is dispatched through PJM. DEQ should consider inviting Dominion to include Mt. Storm as a CO_2 budget source subject to the program, provided that the arrangement does not violate any West Virginia CO_2 rule and is acceptable to RGGI. The plant is old and a substantial source of CO_2 and other pollutants. We are not aware of any barrier to Dominion's agreeing to subject this plant to Virginia's CO_2 program, which would affect PJM's economic dispatch of the plant, but not require any plant modifications or state permits. Dominion and its customers could benefit from phasing down Mt. Storm's operations and shifting CO_2 allowances to newer, cleaner facilities located in Virginia.	Unless and until West Virginia links to the RGGI program, it is unlikely that they would expect for Mt. Storm to submit to RGGI requirements.
155. Virginia Chapter of the Sierra Club et al.	The proposal wisely does not provide for creating offset allowances. Offset allowances would require large investments of Virginia's administrative resources to analyze, approve and enforce proposals. Nearly 30% of the RGGI Model Rule text is devoted to standards and procedures for evaluating, approving, and enforcing offset projects. That is not a burden that Virginia should take on, particularly since it may require physical and economic processes beyond those DEQ normally oversees. Further, the value of offsets is dubious. Even if they reduce CO_2 somewhere, offset schemes may not provide ancillary benefits from reducing power plant emissions of CO_2, including benefits from reducing co-pollutants. Indeed, offset projects may increase the danger that local pollution will increase as a result of purported CO_2 reductions at remote locations as has happened under California's program.	DEQ agrees with the commenter that implementing offsets is not desirable at this time; see the response to comment 26.
156. Tenaska Virginia Partners, L.P.	DEQ projects annual CO_2 emissions from covered facilities to be 36.8 million tons in 2019. Under the 34 million ton alternative, a 7.6% reduction would be required in the first year of the program. If the more stringent 33 million base budget were used, a 10.3% reduction would be required. These are 2.5-3.5 times the proposed 3% annual cap decline in subsequent years. Tenaska strongly suggests DEQ consider a higher base	See response to comment 37 for a discussion of how the final base cap was determined. DEQ is assisting affected sources in meeting compliance costs by

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	budget, such as 35 million tons, in the event the 2019 emission projection is proven accurate. At the very minimum, 34 million tons should be used. Tenaska strongly favors the "generation updating" approach, whereby covered facilities are allocated allowances according to their respective historical annual net generation as compared to the total aggregate generation from covered facilities, averaged over the immediate 3 calendar years, updated annually (i.e., on a rolling 3-year average). Tenaska believes this approach best meets the intent of the regulation, in that it incentivizes more efficient units that emit less CO_2 per unit of power produced. Note that Regulatory Advisory Panel (RAP) participants favored this option. As presented during RAP meetings, Tenaska's Virginia Generating Station in Fluvanna County currently operates under a long-term contract or "tolling agreement" with a third party, whereby the third party procures the fuel and purchases the generated electricity. The term of the agreement is 20 years and expires in May 2024. Under the terms of the agreement, Tenaska believes it has the ability to pass through to its customer costs for things such as emissions allowances, whether they be for the Acid Rain Program, CSAPR, or any future carbon trading scheme. However, Tenaska's customer has taken the position that Tenaska does not have such a pass through right. These costs are projected to be $2.30/MWh in 2020 and $3.78/MWh in 2031, representing an increase of 14.6-18.9% over the projected wholesale power price. To the extent Tenaska is required to purchase allowances and is unable to pass through those costs to its customer, it will be disadvantaged compared to other generators that can either recoup those costs or that have no costs due to their location in another PJM state without a carbon pricing scheme (e.g., Pennsylvania and West Virginia). Several RGGI states and every major proposed federal CO_2 cap and trade legislation has recognized this predicament and provided various forms of relief, such as creating an allowance set-aside for free allocations or offering allowances at a reduced price. Tenaska requests DEQ also recognize this and either create a set-aside sufficient to cover net allowance obligations for LTC holders or simply exempt LTC holders for the life of the applicable contracts. The set-aside would be less disruptive to the program as it would alleviate units entering and exiting.	issuing allowances. The amount of compliance costs covered by the allowances will depend on business decisions made by any individual facility. If a facility stays within the budget, it will not incur costs.
157. Tenaska Virginia Partners, L.P.	We encourage DEQ to expand the scope of the regulation to include additional sources and seek meaningful reductions in other sectors of the economy (via alternative pathways), including mobile sources, if the dire consequences referenced are to be avoided.	As discussed in the response to comment 65, this exemption is appropriate. While DEQ agrees that other pathways

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	One such way is to remove the exemption in 9VAC5-140-6040 B for units that generate electricity and heat "for the primary use of operation of the facility." CO_2 emissions from such facilities are no less potentially harmful than those from units that generate electricity for off-site use. Neither the RGGI Model Rule nor the environment make such a distinction and neither should DEQ.	to CO_2 reductions are important, the scope of the regulation is limited by executive order and state law. DEQ believes that the 5% DMME set-aside as well as other ongoing programs such as the Grid Transformation and Security Act of 2018 will provide additional incentives for energy efficiency and renewable energy.
158. U.S. Green Building Council (USGBC)	We agree with the proposal to link Virginia with RGGI, creating opportunities for cost and resource reduction. DEQ should reconsider the 2020 emissions baseline to ensure it meets the objective of capping emissions. The 33 million ton baseline is higher than the 2017 carbon emissions of 31.2 million tons, while energy productivity is increasing. These data suggest that a lower baseline will be more successful at driving reductions. Subsequent to DEQ projections, the General Assembly passed SB966, which could affect the baseline generation from fossil fuel power plants and their carbon emissions. We recommend increasing the 5% set aside. Such set-aside funds are critical to expand DMME programs, which for some sectors are the primary potential source of energy efficiency assistance given SCC limitations on efficiency programs. The majority of the set aside should directly benefit low and moderate income persons and areas. It is well established that disadvantaged populations are disproportionately impacted by air pollution. Moreover, programs aimed at increased efficiency in low and moderate households have a co-benefit of reducing their vulnerability to electricity rate increases. The regulation should provide for DMME to actively seek public input on use of the set aside including how the proposed use benefits target populations. DMME and DEQ should study and monitor potential impacts of the regulation on low and moderate income households, and periodically report findings to the public.	See comment 37 for a discussion of how the final base cap was determined. As discussed in the responses to comments 51 and 53, a 5% set-aside is appropriate in the early stages of the program. The specifics of how this set-aside will be managed will be determined by DMME. DEQ agrees that vulnerable communities must be addressed, and the program contains multiple opportunities to do so; see the response to comment 55 for more information.
159. Environmental and Regulatory Law Clinic, University of Virginia	Given the climate change-related threats facing our state--and considering the sources of pollution in Virginia that contribute directly to those threats--it is entirely appropriate and necessary for the board to initiate a regulatory program linking Virginia to RGGI. The Office of the Attorney General issued an official advisory opinion that analyzed the relevant statutory and administrative authority and concluded "that the State Air Pollution Control Board is legally authorized to regulate GHG emissions." Specifically, the Attorney General	Support for the proposal is appreciated. DEQ agrees that the board and department have the legal authority to develop the proposed regulation; see the response to comment 76 and, for example, comment 139.

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	noted that the board is authorized to regulate "air pollution" in the state, and observed that GHGs unquestionably fall within the definition of "air pollution." The Attorney General further concluded that because of its "broad statutory authority" under Va. Code § 10.1-1307(A), the board can exercise its regulatory authority through imposition of a "statewide cap on GHG emissions." The board also has the authority to maximize the efficiency and efficacy of a statewide cap by linking the program with RGGI. A state-led program is not preempted by the federal Clean Air Act, and is, in fact, specifically authorized by the Clean Air Act's state law savings clause (42 USC § 7416).	
160. Virginia Loggers Association (VLA)	Virginia's land cover is approximately 62% forested; in total, 15.8 million acres of forest with about 12.2 million acres are owned by private individuals, corporate and non-profit organizations. The majority of Virginia's forests are owned by individuals. Timber production is an important part of Virginia's economy and environment. The most recent study released by Governor McAuliffe shows that our forest products industry is the third largest contributor to Virginia's economy. The study revealed that almost $9.3 billion were added directly due to forests. Most of these forests are managed through the most current science enabling our forests to be productive for timber products and environmental benefits. Our forests are healthy and have increased in volume since inventory studies in 1940s. Virginia's forests are growing at a faster rate than harvest removal and mortality. The latest inventory shows that softwood annual growth to annual harvest is at a ratio of 2.2:1 and hardwood annual growth to annual harvest is 2.4:1. Our forests clean the air, sequester carbon, and improve water quality, wildlife habitat and recreational opportunities while producing products for many. Biomass is an important component of Virginia's energy policy. Many of our members invested millions of dollars in equipment to provide biomass to utilities across Virginia. We ask that any regulation recognize the investments made by our mills and logging businesses as well as the renewable natural qualities of forests. Some areas of the proposal would require our mills to invest further for monitoring biomass sources currently not required. We ask that you remove any additional requirements on biomass based sources. Continue to treat biomass as carbon neutral. Finally, we ask that DEQ maintain the current exemption of industrial boilers.	The commenter's concerns are appreciated. See the responses to comments 65 and 67 for further detail.
161. Virginia Energy Efficiency Council (VAEEC)	Energy efficiency is one of the most cost-effective tools to reduce energy consumption and dependence on fossil fuels, which in turn helps reduce carbon emissions. We applaud the inclusion of the 5% set aside for energy efficiency programs. Expanding energy efficiency provides Virginia residents with affordable energy bills and healthier, more comfortable homes. Last year, the American Council for an Energy-Efficient Economy	Support for the proposal is appreciated. DEQ agrees that energy efficiency is an essential component of reducing carbon emissions.

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	(ACEEE) listed Virginia as one of the most improved states in their 2017 State Energy Efficiency Scorecard. Moving from 33rd to 29th place underscores the work VAEEC, our members and our partners have done to advance energy efficiency policies and initiatives. But there is more that can be done to help Virginia break into the top 25. The passage of the Grid Transformation and Security Act paves the way for greater opportunities as well. These programs, in addition to the energy efficiency carve out will propel Virginia into the spotlight as a leader on energy efficiency.	
162. Virginia Coal and Energy Alliance (VCEA)	The benefits provided by the coal and coal-related industries should only be placed at risk if the justification for doing so is clear--that is, if the benefits from the burden placed on those industries are greater than the benefits they provide. Unfortunately, the justification provided for the CO_2 Trading Rule is anything but clear, as it unfairly compares an underestimated assessment of real-world local costs and economic impacts to a theoretical and now-rejected overestimate of global benefits. The justification proffered for the proposal contains a logical disconnect. The justification, which is based on the Report of the EO 57 Work Group, proceeds as follows: 1) climate change causes certain harms in Virginia (e.g., heavy storms, water shortages, and warmer temperatures); 2) therefore, reducing the GHG emissions in Virginia will reduce those harms and benefit Virginia. However, that assumes that reducing CO_2 emissions will address harms here. Contrary to that assumption, reducing emissions in Virginia will not have any impact on the earth's climate. Emissions from Virginia--indeed, the entire U.S.--are such a small portion of total global emissions that any reductions are almost certain to have no meaningful effect. The benefits alleged in support of the rule are based almost entirely on the "social cost of carbon," a metric crafted by a disbanded interagency working group under the Obama Administration. The Trump Administration has rejected that metric and directed that it no longer be used to justify federal regulations. The social cost of carbon analysis admits a critical point: "[e]ven if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change." That confirms that even those in favor of climate change policies must recognize that the reductions from any one country, much less any one region or state, will not change anything. The social cost of carbon itself is flawed because it relies on a highly speculative evaluation of global benefits, followed by an unfair comparison of those worldwide benefits to domestic costs incurred within the U.S. alone. Not only is that comparison unreasonable, since	The board is within its legal authority to address carbon pollution, which poses serious threats to the Commonwealth, through a cap-and-trade program; see the responses to comments 61 and 76.

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	worldwide benefits will always dwarf the costs incurred by a single nation, it also represents a break from the manner in which the impact of regulations has always been evaluated. U.S. costs have always been compared to U.S. benefits in order to provide a fair basis for the comparison, even for regulations that may benefit other countries. With the withdrawal of the social cost of carbon from federal policy, federal agencies must now return to that more reasonable and well-understood approach, and DEQ should do the same. The other justification relies on co-benefits associated with reductions in other pollutants, such as NO_X, SO_2, and particulate matter, which can directly impact human health (unlike CO_2). Co-benefits are not a reasonable basis upon which to justify the rule because the other pollutants are already well controlled by other Clean Air Act programs. Only a small portion of the state is nonattainment for ozone, due to its proximity to the D.C. metropolitan area, not emission sources located in Virginia, and sufficient rules are in place to address those air quality concerns. The rest of the state complies with EPA standards set to protect public health, and no further reductions are needed to maintain compliance with those standards. Claiming that reductions in other pollutants as a justification amounts to double-counting of air quality benefits already achieved and paid for. Although the rule would adopt a seemingly small 3% per year reduction, those compounding reductions will be more significant than the analysis suggests because it ignores and essentially prohibits growth in emissions that would otherwise occur. Whereas the supporting analysis claims a reduction of 30% (from 33-34 million tons in 2020 to 23-24 million tons in 2031), in effect it will actually require reductions of nearly 50% when compared to what would otherwise occur without the program (40-50 million tons). The result will be an increase in the cost of electricity of over 7% and present a significant burden on the coal and coal-related industries. The assertion that emission reductions of a similar magnitude under the proposed rule will have only a minimal impact on the economy of the state is difficult to believe. To combat concerns about the impacts to the economy and the cost of electricity, an analysis was prepared to focus on individual utility bills. The conclusion of that study suggests that the impact to ratepayers will be minimal. However, if that is in fact the case, it must mean the analysis assumes the regulation will not significantly affect the market; that is, the study must have assumed that the market itself would likely encourage nearly the same emission-reducing behavior based solely on the demand for and supply of energy. But if that is true, then	

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	the regulation would not be responsible for any of the emission reduction benefits claimed. The supporters of the proposal cannot have it both ways--either the program will require reductions that would not otherwise occur under existing market forces, in which case significant costs will be incurred in working against the market, or else the market would already encourage the reductions now sought via regulation, in which case the regulation is unnecessary. The General Assembly has already decided that the CO_2 Trading Rule is not in the best interest of Virginia and passed HB1270 to prohibit the very type of program contemplated by the proposal. The Governor vetoed the law and is charging ahead via executive fiat to establish such a program. This scenario is similar to what has transpired at the federal level. Despite the fact that Congress rejected efforts over more than a decade to enact a climate trading program, the Obama Administration decided to establish one through executive authority by issuing the Clean Power Plan, which was based on a few ambiguous and general sentences of the Clean Air Act. So too here, given that the authority claimed by the Attorney General as the basis of the regulation is merely the general authority "to promulgate regulations, including emergency regulations, abating, controlling and prohibiting air pollution." Legislatures grant bold powers in clear terms, and executive agencies should not try to invent bold powers out of ambiguous language. This principle should have equal effect at the federal and state levels, since both governments are based on the same fundamental principle: the legislative branch makes the laws, and the executive branch wields only the authority granted to it by the legislature. Nothing in the Clean Air Act clearly authorized EPA to issue the Clean Power Plan, and that is likely why the Supreme Court stayed it. Those same concerns appear relevant to the proposal, but perhaps to an even greater extent. Unlike Congress, which has been unable to pass a climate change bill, the Virginia legislature did pass one, but one that prohibits what the executive branch is now trying to do on its own. That executive action is only legal if the legislature has already authorized such a program in a previous statute, but it did no such thing. Rather, the statute claimed to be the underlying authority for the regulation is the same type of highly general authority found in the Clean Air Act. Such general grants of authority to issue regulations to address air pollution provide no clear authority for the policy shift the Governor seeks to implement, which represents a decision of economic and political significance. The Governor should not invent that authority, particularly in light of the statement to the	

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	contrary recently made by the legislature.	
163. Virginia Conservation Network (VCN); Virginia League of Conservation Voters (VaLCV)	VCN and VaLCV encourage DEQ to select an emissions baseline that best achieves the goals of reducing statewide carbon pollution. This baseline should be the most stringent, lowest possible science-based figure supported by modeling. For additional details on the stringency of the carbon program, as well as modeling results, please see the technical comments from our partners at NRDC, Sierra Club, and SELC. We are thankful that the regulation covers both current and future fossil fuel-fired units. We were glad to see the inclusion of co-firing units that include at least one fossil fuel-fired unit; however, it should include all electric power facilitates that emit carbon, regardless of fuel type. Specifically, the regulation should apply to any unit at or above 25 MW that burns biomass. For additional details on biomass, please refer to the comments submitted by the National Wildlife Federation. We appreciate and support the 5% set aside of allowances to assist DMME in efforts to address carbon emissions. We encourage DEQ to consider increasing this to 10%, with the understanding the benefits of increasing this figure should be greater than the costs associated for covered sources.	Support for the proposal is appreciated. The commenters' specific issues are discussed elsewhere. See the response to comment 37 for a discussion of the baseline emissions cap, comment 67 for a discussion of biomass, and comment 51 for set-asides.
164. Veolia North America	We commend DEQ for exempting certain industrial combined heat and power (CHP) units from the regulation. CHP plays an important role in the state's clean energy and resilience goals and merits additional support. CHP units deserve special treatment as they have been designed to optimize the efficient production of heat and power for industrial facilities. While the exemption sets a positive policy direction, it needs to be modified to ensure that it rightfully applies to all relevant industrial CHP units. The exemption only contemplates the CHP unit being owned by the industrial end user rather than by a third party. This is counter to the trend of more industrial end users moving to outsource ownership, operation and maintenance of their central utilities. In this model, the industrial company can focus on executing its core business while relying on a specialized third party whose core business is owning, operating and maintaining industrial utilities on a safe, cost effective and reliable basis. As such, the ownership status of the CHP unit is not relevant to the key issue: does the CHP exist to primarily provide service to the industrial end user? Relying on "primary use" intent, rather than regulating CHP ownership, would better focus the regulation on GHG reduction while also allowing the industrial and manufacturing sector in Virginia greater flexibility to achieve this regulatory purpose. We suggest that DEQ remove the phrase "owned by an individual facility and" from the industrial exemption.	DEQ agrees that the phrase "owned by an individual facility" should be removed. Under the RGGI Model Rule, facilities that provide less than 10% of their power output to the grid are exempted from compliance obligations; the proposal has been revised accordingly. The regulation has also been amended in order to address CHPs with more clarity; see the response to comment 74.

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	To qualify for the exemption the useful energy output (thermal and electric) of a CHP needs to be "for the primary use of operation of the facility"; however, "primary use" is not defined. We urge DEQ to clarify the meaning of primary use by considering the magnitude of a CHP's generation of useful thermal energy (UTE) relative to useful electrical energy and by the application of an appropriate CHP efficiency standard. One of CHP's benefits is that it can produce both UTE and electricity from a single fuel source. It is not uncommon for a host to have a high need for thermal energy and a low need for electricity. In order to efficiently service an industrial facility's steam load, a CHP unit may need to be designed in a way that exports a substantial portion of its electric power to the grid. The need to export to the grid is important in circumstances where utility franchise rights prevent third party CHP facilities from delivering power to industrial sites. The integrity of the industrial exemption will be maintained if the focus is on UTE. The industrial exemption can be strengthened by adding an efficiency requirement. This will provide CHP units incentive to maximize requirements of its host rather than exports to the electrical grid. The Virginia legislature recognized the need to encourage CHP systems in the Grid Transformation and Security Act, which requires that the total efficiency, including the use of thermal energy, for eligible CHP facilities meet or exceed 65% (Lower Heating Value) annually. A similar requirement for the industrial exemption would ensure consistency. Veolia recognizes the concept of tying the industrial exemption to a unit "voluntarily restricting its electrical output to the grid (through permit condition) to less than or equal to 10% of the units annual gross generation of the unit." This approach too narrowly restricts what industrial facilities can do with electric generation and conflicts with the broader intent of primary use. Recognizing that not all CHP units will qualify for the exemption, but acknowledging that these units still deliver valuable GHG reductions, we recommend a UTE exemption. CHP units over 25 MW that do not qualify for the industrial exemption, must procure CO_2 allowances for all emissions, including those associated with UTE (i.e., microgrid, district energy, process steam, hot water). Absent production at a CHP unit, the UTE would be produced by conventional methods, such as standalone boilers. These conventional methods of generating UTE are not subject to the regulation, and thermal generation-only unit owners are not required to procure CO_2 emissions allowances. If CHP units over 25 MW are required to procure CO_2 allowances for all emissions, including those associated with UTE, it will create a counterincentive and potentially increase GHG emissions. To avoid this, the regulation should exclude	

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	CO_2 emissions associated with UTE from a CHP unit. When determining the RGGI emissions allowance compliance obligation for a CHP unit, emissions associated with UTE of that unit should be deducted from the unit's total emissions. There is precedent for adopting a UTE exemption based on existing UTEs in federal and state agency carbon trading programs. EPA's Clean Power Plan included a UTE exemption for CHPs. Several RGGI states have adopted a UTE exemption in different forms. For example, Massachusetts has an exemption for any CHP CO_2 budget source that allows the CHP unit to subtract from its total CO_2 emissions the amount of CO_2 emissions attributable to the production of useful net thermal energy. The Massachusetts regulation acknowledges that, absent production in a cogeneration unit, UTE would be produced in a standalone boiler. These boilers do not have a compliance obligation under any RGGI program, and have no mandated efficiency targets. With this UTE exemption structure, a generation unit has an incentive to maximize useful outlets for its waste heat. The Massachusetts UTE exemption is the most effective and straightforward approach, and we encourage DEQ to adopt a similar exemption. Under this approach, emissions associated with UTE are calculated on a formulaic basis and are subtracted from a CHP's compliance obligation. Note that the exemption is only for emissions associated with UTE. CHP units that fall under RGGI will still be required to procure allowances for any emissions not associated with UTE. However, with the UTE exemption, CHP will be on equal footing with conventional generators whose only output is electricity. By reducing a unit's environmental compliance costs, the UTE exemption removes a potential barrier for investment in CHP. The ability for a CHP unit to exclude emissions from UTE from its compliance obligation will become even more important in the future. With the RGGI emissions cap declining each year, it is likely that RGGI allowance prices will continue to increase. As RGGI allowance prices increase, they will drive up compliance costs and increase the economic disincentive faced by CHP units. Without a UTE exemption, there will be a similar adverse effect on existing facilities that have the option of using CHP to generate UTE or using stand-alone boilers. As the costs of CHP rise due to higher RGGI compliance costs, the dispatch of equipment may change resulting in more standalone generation of UTE and higher regional carbon emissions.	
165. Virginia Forest Products Association	VFPA does not support joining RGGI because it would raise electric power and natural gas rates. This is a grave concern to our small businesses, as even small sawmills without kilns have electric bills that average	The commenter's concerns are recognized. See the response to comment 67 for a discussion of

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(VFPA)	$6,000/ month. Kiln dryers add substantially to that monthly bill, and larger mills with kilns have monthly electric bills in excess of $20,000. Our primary competition is in North Carolina, not the RGGI states, and an increase in our utility rates will put us at a competitive disadvantage. A more critical concern is the potential impact if emissions from the combustion of biomass are treated as GHG. Lumber production produces manufacturing residuals in the form of mulch, sawdust and chips. Even a small mill can produce 25 tons per day of dust and chips each. There is a ready supply of wood residuals from sawmills in the state that require a variety of markets. Having ready outlets to dispose of residuals is critical; we can't saw lumber if we can't move residuals off the yard. We are extremely concerned that disincentivizing the burning of biomass for power could negatively impact sawmills, loggers, and landowners by reducing or eliminating that market. The boiler fuel outlet for residuals is key to our survival; if it is treated the same as any other fossil fuel but costs more for the utility to procure, they will no doubt select the less expensive option since the benefit is removed. The science on the carbon neutrality of woody biomass is solid, and VFPA supports the comments and supporting data submitted by AF&PA and AWC. Harvesting wood for energy does not contribute to net carbon emissions in cases where the harvesting, measured over a broad region, is offset by wood growth and associated carbon sequestration. The most recent data from the U.S. Forest Service indicate that timberlands in Virginia, the U.S. south, and the entire country have highly positive net growth/removal ratios. The Virginia Department of Forestry's Reforestation of Timberlands Program has reforested 1.8 million acres since the program's inception. This program provides cost-share assistance to landowners in planting, replanting, and managing forest acreage. Since 1970, landowners and industry have reforested 4 million total acres in Virginia. U.S. Forest Service data from 2016 shows growth/removal ratios for timberlands in Virginia, the U.S. South, and the nation as a whole are 2.29, 1.76, and 1.94, respectively. In other words, Virginia's timberlands are growing more than twice as much wood as harvested, while timberlands in the south grow 76% more than is harvested. When environmental organizations cite the cutting of trees by the forest product industry as inherently negative, they ignore the cyclical nature of managed timberlands. The most significant pressure on forests is permanent conversion to non-forest uses, such as development. However, strong markets for wood are the	biomass. The industrial exemption will be maintained; see the response to comment 65.

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	most powerful incentive to keep forests in production. From the sawmills' perspective, markets for the finished product and residuals on the back end are as important as the supply of trees on the front end. A balance in supply and demand will keep businesses and forests healthy. A 2014 article in the Journal of Forestry noted that if mill residues were not used for energy, most of these materials would be wastes that would either be incinerated, in which case the atmosphere would see the same CO_2 emissions as if the material had been burned for energy, or disposed of in landfills. The article further states that the net impact of burning for energy on biogenic emissions in terms of warming can be less than zero because of the warming potency of methane generated in landfills. In the past, many sawmills burned wastes on site in large incinerators as there were not enough markets for the materials. Residuals build up quickly in the process of sawing lumber. If today's mills lose too many markets for residuals, the financial burdens of incinerating on site or the costs of landfill tipping fees for disposal of thousands of tons of residuals would force many sawmills to cease operation. From economic and environmental perspectives, treating biomass as carbon neutral in energy production makes dollars and sense. VFPA respectfully requests that Virginia not join RGGI. However, if the state does join RGGI, we ask that biogenic carbon emissions be recognized as carbon neutral regardless of whether other fuels also are co-fired; and that the exemption for industrial boilers be retained. This regulation is designed to address utility electrical generation only; the exemption for on-site industrial generation should remain in the final rule. This is also important because of potential market impacts to saw mills if large industrial users lose this incentive for firing with biomass.	
166. Virginia Chamber of Commerce	The Virginia Chamber recently released Blueprint Virginia 2025, a plan that outlines the business community's priorities and recommendations for making Virginia the best state for business. Throughout our stakeholder engagement process, which included over 6,000 members of the business community, we heard from business leaders on how important affordable, reliable energy is to Virginia's economic competitiveness. Energy affordability was identified by 55% of Blueprint survey respondents as their top energy concern. Unfortunately, RGGI is not consistent with the Chamber and Governor's goal to make Virginia the best state for business, as it will increase electricity rates and make Virginia less competitive. The Chamber supports policies that promote energy independence and the development of a robust supply of energy. We advocate an energy portfolio that promotes	The regulation is designed to impose regulatory requirements only as strictly necessary in order to participate in the highly successful RGGI program without affecting economic competitiveness. As discussed elsewhere, the regulation retains exemptions for certain industrial and biomass facilities, and provides for free allowances. Note that RGGI's "CO_2 Emissions from Electric Generation and Imports in the Regional Greenhouse Gas Initiative:

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	economic development and job growth through traditional and alternative energy investments, and believe that environmental protection and energy independence are compatible goals. It is expected that energy consumption in Virginia will continue to rise, reflecting the increase in population, economic growth, and electrification of the transportation system . To ensure a growing economy, we must develop strategies for an ample supply of affordable and reliable energy. Part of achieving our goal of being the best state for business is to protect our competitive rates for electricity. Business climate rankings factor energy and utility costs into their "cost of doing business index," which can influence our overall position. Favorable energy costs are important in order to remain economically competitive. By joining RGGI or initiating a cap-and-trade program, energy costs for employers and residents will rise. According to a recent Cato Institute study, the RGGI program creates higher electric bills and shifts jobs to non-RGGI states. According to the U.S. Chamber of Commerce's Global Energy Institute, the average electricity rate of the RGGI states is 39% higher than the national average. By contrast, Virginia has the nation's 19th lowest average electricity rates, 12% cheaper than the national average. Virginia's affordable rate provides the state a competitive advantage when it comes to attracting manufacturing and other energy intensive industries, such as high-tech data centers. Any program that would increase electricity rates--such as RGGI--would reduce this competitive advantage. Further exacerbating the negative effects to our economic competitiveness is the problem of carbon leakage. The state's own modeling illustrates the potential impacts of leakage that could result from partnering with RGGI. Participating in RGGI is likely to increase electricity imports into the state. Because many of the neighboring states in the PJM electricity region do not participate in RGGI but are powered by resources with a higher carbon intensity, shifting generation from Virginia into these states may result in an increase in emissions. Under this scenario, Virginia suffers the economic consequences of joining RGGI while achieving no progress toward its environmental goals. While RGGI backers cite the program as a successful cap and trade model, there is little evidence to suggest that the program has been effective at reducing emissions. The Agency Background Document states that a primary advantage to the public of joining RGGI would be "health and welfare benefits associated with controlling carbon pollution." In the Economic Impact Analysis, DPB estimates that the benefits of the state's effort to reduce CO_2 would be between $42-50 million	2015 Monitoring Report" demonstrates that carbon emissions in the RGGI are decreasing in intensity; essentially, carbon intensity is being decoupled from electricity generation. See, for example, the response to comment 61. The regulation has been carefully designed to be least restrictive to Virginia business, does not hurt the state's economic competitiveness, retains an industrial exemption, exempts certain forms of biomass, and provides for free allowances.

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	annually between 2021-30. Note that the social costs of carbon are controversial and uncertain, based on long-term assumptions about the damages that may result from increased carbon emissions. As DPB notes, the $42-50 million of CO_2 reduction benefits are global, not Virginia-specific. DPB states that it is "not possible to quantify the Virginia-specific benefits," but this is not accurate; a number of analysts employ the use of "equity weighting" as a means to compare impacts to different regions. EPA and other federal agencies now use this method to develop domestic-only estimates of the social cost of carbon (SC-CO_2). We can estimate the benefits to Virginia similarly. When applied to calculate a Virginia-specific benefit, the mid-range of OPB's estimate of $46 million in SC-$CO_2$ benefits is reduced to a mere $250,000. This is because, at the mid-range of the program (2025), U.S. GDP is projected to be 20.5% of global GDP, and Virginia GDP is 2.7% of U.S. GDP ($46 million X .205 X .027 = $250,000). Divided by Virginia's estimated reductions of 1 million tons per year, this equates to a benefit to Virginia of 25 cents per ton of CO_2 reduction. Viewed in this Virginia-specific manner, it is difficult to see how the program's costs justify its projected benefits. If Virginia does move forward with this proposal, we ask that the regulation be least restrictive to Virginia businesses, does not hurt the state's economic competitiveness, retains an industrial exemption, treats biomass as carbon neutral, and provides for free allowances as opposed to an auction.	
167. Virginia Housing Alliance	We recommend that the 5% allocation be used for energy efficiency services for renters in multifamily housing. Energy efficiency in multifamily housing can help Virginia meet the state's voluntary goal to reduce electricity consumption for commercial and residential buildings by an amount equal to 10% of 2006 consumption by 2020 in addition to reducing carbon pollution for compliance with ED 11. If used for energy efficiency, the allocation will reduce energy use and carbon emissions, reduce the need for added electric generation, improve public health and environmental quality, boost job creation, and preserve affordable housing. We support Virginia's entrance into RGGI and hope that energy efficiency will be regarded as a necessary and cost effective tool for Virginia's transition to a clean energy future.	DEQ recognizes the value of energy efficiency in multifamily housing as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement renewable energy and energy efficiency programs. DMME may, at the appropriate time and in accordance with its regulations and policies, implement a set-aside for energy efficiency in multifamily housing. See the response to comment 51 for more information.
168.	While WestRock generates a considerable portion of its	The commenters' concerns

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WestRock; Covington, Hopewell and West Point mills	own energy at our largest manufacturing facilities, having access to sufficient quantities of utility-provided electricity at reasonable prices is critical for reliability and economic reasons. Some of our mills are entirely energy independent, but others must purchase a significant portion of their electricity from the grid. Our converting operations in Virginia rely heavily on purchased electricity. West Rock spends over $100 million annually on energy in Virginia. As a large electricity consumer in the state that also uses considerable amounts of biomass for energy generation, WestRock will be substantially affected by the proposed rule. We are a member of AF&PA and NCASI, and support the comments submitted by these organizations.	are acknowledged. See the responses to comments 65 and 67.
169. WestRock; Covington, Hopewell and West Point mills	The proposed rule states that if biomass comprises 90% or more of the total heat input to an electric generating unit, the unit and its biogenic CO_2 emissions are not regulated. However, if biomass comprises less than 90% of the heat input to an electric generating unit, biogenic CO_2 emissions are regulated and allowances must be remitted for CO_2 emissions from that unit. This treatment of biogenic CO_2 emissions is arbitrary and capricious. Biomass carbon neutrality does not change based on the amount of biomass fired, nor does it change when biomass is co-fired with other fuels. The treatment of CO_2 emissions from the combustion of biomass represents a significant departure from current U.S. federal law, internationally-accepted carbon accounting protocols, and the RGGI model rule. The carbon benefits of biomass are best understood in the context of the entire carbon cycle. As forests grow, CO_2 is removed from the atmosphere through photosynthesis. This CO_2 is converted into organic carbon and stored in woody biomass. Trees release the stored carbon when they die and decay or are combusted. As the biomass releases carbon in the form of CO_2, the carbon cycle is completed. The carbon in biomass will return to the atmosphere regardless of whether it is burned to produce energy, allowed to biodegrade, or lost in a forest fire. Overall, the flow of forest CO_2 is carbon positive when forests are sustainably managed and the forest system remains a net sink of CO_2 from the atmosphere. Carbon stock accounting shows that carbon storage in U.S. forests is positive and currently offsets about 12% of total U.S. CO_2 emissions annually. In Virginia, the growth of the state's forests offsets about 14% of the total annual CO_2 emissions. In 2014, the ratio of the forest's annual growth compared to harvest volume was more than 2.1:1 for softwood and 2.2:1 for hardwood. This amounts to an annual surplus of 8.4 million tons of softwood and 14 million tons of hardwood. Biomass residuals from the manufacturing process are used as the primary fuel to power paper mills. If these residuals are landfilled	The commenters' discussion of biomass and forest lands is appreciated. As discussed in the response to comment 67, certain biomass facilities will not be subject to the program. RGGI states allow CO_2 budget units that co-fire eligible biomass to deduct CO_2 emissions attributable to the burning of eligible biomass from their compliance obligation in accordance with the RGGI model rule. DEQ has amended the proposal to indicate that a CO_2 allowance is a limited authorization to emit up to one ton of CO_2 that has been generated as a result of combusting fossil fuel. The regulation has also been amended in order to address CHPs with more clarity; see the response to comment 74.

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	instead of being used as fuel, they would release GHG to the atmosphere, increasing emissions of methane, which has a global warming potential 25 times higher than CO_2. In addition to utilizing residuals, more than 97% of electricity produced by pulp and paper mills is generated through the use of highly efficient CHP. CHP provides energy efficiencies in the range of 50% to 80% at forest products mills. In the 2018 Consolidated Appropriations Act, Congress directs EPA, DOE, and USDA to ensure that federal policy relating to forest bioenergy is consistent across all federal agencies and recognizes the benefits of forest biomass for energy, conservation, and responsible forest management. Several states also have laws recognizing the carbon neutrality of biomass, including Washington and California, and RGGI itself states: "CO_2 emissions from eligible biomass reduce the total CO_2 allowance compliance obligation of the emitting unit. Emissions from eligible biomass should be deducted from the regional total of CO_2 emissions for purposes of calculating emissions from CO_2 budget sources subject to RGGI CO_2 allowance compliance obligations." Biomass CO_2 emissions are either not reported or reported separately or for information purposes in many domestic and international GHG regulations and protocols, including the World Resources Institute/World Business Council for Sustainable Development, and the U.N. Intergovernmental Panel on Climate Change. The board seeks comment on the potential impacts of the rule on forest land preservation. Studies show that recognizing the carbon neutrality of biomass will not negatively impact forest inventories due to the availability of lower cost renewable fuel options. In one such study, the Energy Information Administration (EIA) modeled the potential impact of the Clean Power Plan on the use of biomass for energy generation. In all EIA scenarios, co-firing biomass was projected to decrease under the CPP. In the long term, biomass is not a strategic, large scale, cost-effective alternative to fossil fuel. EIA modeling shows that standalone biomass energy plants are not considered cost competitive. In a recent article, EIA discusses the costs of various electricity generation technologies. The article shows that by 2022, onshore wind will have a lower levelized cost than biomass in all U.S. regions, and solar photovoltaic will be less costly than biomass in some regions. Subsidies will tend to make solar and wind even more competitive. Studies also show that demand for biomass helps prevent forest land from being converted to other uses. A Department of State report shows that demand for forest products will increase forest carbon stocks through landowner investment. Markets for biomass and other	

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	forest products stimulate forestland ownership and encourage investment in healthy forest management practices. Farmers and forest owners, as with all business owners, respond to markets and produce more when demand increases. The most significant deforestation threat in the U.S. is forest conversion. Current forest inventories and the net sink are subject to the protections of a state law that caps the amount of biomass that Virginia utilities may use for energy under the Renewable Portfolio Standards program. Virginia Code 23 VAC 56-585.2 states: "Utilities participating in such program shall collectively, either through the installation of new generating facilities, through retrofit of existing facilities or through purchases of electricity from new facilities located in Virginia, use or cause to be used no more than a total of 1.5 million tons per year of green wood chips, bark, sawdust, a tree or any portion of a tree which is used or can be used for lumber and pulp manufacturing by facilities located in Virginia, towards meeting RPS goals, excluding such fuel used at electric generating facilities using wood as fuel prior to January 1, 2007." To the extent the regulation requires the monitoring and reporting of GHG emissions, WestRock urges the board to allow covered facilities to separately calculate and report biogenic and fossil fuel CO_2 emissions as is currently allowed under various established GHG reporting protocols.	
170. WestRock; Covington, Hopewell and West Point mills	The proposal excludes industrial sources from coverage, and WestRock supports this. EO 57 and ED 11, the authorities upon which the proposal is based, limit the scope of the rulemaking to the electric power generation sector. ED 11 states that the DEQ Director shall, in coordination with the Secretary of Natural Resources, "develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit CO_2 from electric power facilities." EO 57 is similar. These directives manifest a clear intention to exclude industrial sources. Neither the Economic Impact Assessment, the proposed emissions cap, nor the allowance allocation and price modeling conducted by DEQ and its consultants included emissions from industrial sources. Similarly, the charge given to the Regulatory Advisory Panel did not include industrial sources. Inclusion of industrial sources is unnecessary and cannot be justified on a cost/benefit basis. According to EIA, industrial sources in Virginia emit 11.6 million tons of CO_2 and comprise 11 % of emissions in the state compared to 30% by the electric utility sector, and 43% by the transportation sector. EPA data indicates that GHG emissions from Virginia's industrial sector have decreased 31% since 2000. On the other hand, including	The industrial exemption is discussed in the response to comment 65. Consistent with the RGGI model rule, the proposal has been amended to remove the phrase "owned by an individual facility" in order to ensure that facilities are not be penalized for employing more energy efficient and less polluting generating systems that may be operated by a third party on behalf of the primary facility. The regulation has been amended in order to address CHPs with more clarity; see the response to comment 74.

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	industrial sources would cost Virginia businesses $18.9 to $41 million. The exemption is consistent with the intent and scope of the existing RGGI program, which does not regulate emissions from industrial sources. In fact, except for the purposes of reporting, there do not appear to be any industrial sources listed in the RGGI CO_2 Allowance Tracking System's list of regulated sources. Including industrial sources would not only put the state at odds with other RGGI participating states, it would put Virginia industry at a competitive disadvantage. RGGI allowance prices are based on the marginal cost to reduce GHG emissions from the utility sector and do not reflect the ability for industrial sources to reduce emissions. Subjecting industrial facilities to allowance markets that are not reflective of their own marginal costs would be unfair and poor public policy. The exemption should be clarified by adding the definition of electric generating unit found in VA Code 10.1-1328 to distinguish between industrial and electric power facilities as it relates to the term "primary use." Steam and electricity generation at an industrial facility is almost without exception for the primary use of the facility. However, actual flows of electricity may reflect buy-sell contractual arrangements or engineering constraints. It is not uncommon for an industrial CHP facility generating electricity to meet the primary needs of its operation, to export all that it generates and purchase 100% of its electricity needs. For the purposes of determining "primary use of the operation," it is imperative that net electricity flows be considered to ensure that industrial generation is not unintentionally included simply by virtue of contractual arrangements or the nature of its physical connection to the grid. Although WestRock owns its onsite CHP operations, in some cases CHP operations may not be owned by the facility where they are located due to financing arrangements. To promote the use of CHP, DEQ should remove the requirement that fossil fuel power generating unit located at an industrial facility also be owned by the facility.	
171. WestRock; Covington, Hopewell and West Point mills	If the rule is promulgated, electricity costs in Virginia will rise. DEQ's economic analysis suggests that the impact of this cost increase will be no more 1.1% by 2031. However, other studies suggest that the increase in electricity prices may be far more significant. According to a report cited by VMA in its comments, electricity costs in the RGGI states rose by 4.6% between 2007-15, which was 64% higher than the increase in electricity costs in a sampling of 5 non-RGGI states. Increases in the cost of electricity for large consumers like WestRock may make Virginia a less attractive place for investment than neighboring states without carbon reduction mandates. Increases in electricity costs may lead to the	As discussed in the response to comment 91 and elsewhere, while generation shifts are common in a regional electricity market, there are many reasons to believe that the trading program is unlikely to cause generation shifts and, if it does cause some shifting, reasons to doubt those shifts will lead to emissions

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	use of more imported electricity from areas without CO_2 reduction mandates, which may undermine any environmental improvements from the proposal. We encourage the retention of free allowances and a cap of 34 million tons (or higher), both of which may help moderate the cost of the program. WestRock, the industrial sector, and the utility sector have significantly reduced their GHG emissions through capital investment in more energy efficient energy generation, production processes and the use of lower carbon fuels. This trend is expected to continue both through ongoing capital investment and as part of the commitments made by WestRock and others to meet voluntary GHG reduction goals.	leakage. The RGGI states have not found leakage to be a problem for the program in 10 years the program has operated. The program is quite modest relative to other cost factors in the regional electricity markets and any shifting is likely to substitute one gas plant for another, meaning the emissions consequences are not significant. The Virginia program includes an allowance allocation approach that will directly counteract any leakage pressure, because in-state generators will be rewarded with valuable allowances when they operate, while generators outside Virginia will not be so rewarded. In addition, vertically integrated utilities can self-schedule their generators to run knowing that they will receive allowances at no cost under the program, offsetting any compliance cost the generators might otherwise incur. For all of these reasons, leakage is not expected to present a problem. DEQ expects to monitor this issue as RGGI has done and will address the issue should it be necessary in a future program review. The cap will be 28 million tons (see comment 37), and the allowances will be provided at no cost.
172. Wild Virginia	Article 1 states that the trading program is "designed to reduce anthropogenic emissions of CO_2." However, if the rule applies only to fossil fuels and not other carbon emitting generation, it cannot achieve its goal. According to EPA, total CO_2 emissions from the burning of woody biomass in the electric power sector was 22,900,000 tons in 2016. The proposal applies only to fossil fuels, not biomass or municipal waste. This would allow Virginia's wood burners to continue polluting without regulation and reward coal-fired power plants that switch	See the response to comment 67 for further discussion of biomass.

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	to burning wood from forests. Burning wood to produce electricity increases CO_2 and particulate emissions compared with fossil fuels. Besides undermining efforts to expand clean energy sources, burning forests for energy destroys forest ecosystems which are a defense against climate change. The regulation could encourage more biomass generators to be implemented. Westrock operates the world's largest solid bleached sulfate board paper mill in Covington. It is powered by a biomass boiler and a 75 MW steam turbine generator. In 2016, this facility emitted 2,020,927 tons of CO_2. NOVEC's Halifax plant generates 50 MW of energy, sourcing wood and whole trees from a 75-mile radius while claiming that its energy is carbon neutral. The 585 MW Virginia City Hybrid Energy Center co-fires coal with 20% wood. It emitted 3,101,460 tons of CO_2 in 2016. Dominion's 83 MW Pittsylvania station unloads an estimated 3,300 tons of wood daily. Dominion's Altavista plant turns pellets, chips, slash, or whole trees into 51 MW of energy, and in 2015 released 393,183 tons of CO_2. Dominion received regional renewable energy and federal incentives by converting 3 coal-fired plants to burn wood. In 2016, Dominion's conversion from coal to wood in Hopewell and Southampton has more than doubled carbon emissions from those facilities. In 2016, these facilities together emitted 885,063 tons of CO_2. Wood-burning power plants pump about 50% more carbon pollution per megawatt-hour into the atmosphere than coal plants. Combined, Virginia's wood-pellet manufacturing and wood-burning power plants send more than 5 million tons of CO_2 mostly from forest wood into the atmosphere each year. Power plant carbon pollution warms the climate just as effectively whether it comes from burning trees or fossil fuels, which highlights the critical fallacy of treating biomass power plants as "carbon-neutral." Virginia's plan isn't unique in ignoring emissions from wood-burning plants. The problem also exists with California's cap-and-trade plan, RGGI, and the E.U. trading program. Much of the emissions reductions claimed by the E.U. come from converting coal plants to burn wood pellets imported from the U.S. and Canada, then assuming the emissions will be offset by future tree growth. As a result, millions of tons of trees are harvested, pelletized and shipped overseas as fuel. The pellet industry is responsible for logging tens of thousands of forest acres each year. Burning municipal waste is also a large emitter of carbon. For example, the Hampton/NASA Steam Plant released 24,653 tons of carbon in 2016. We request that the regulation include carbon accounting	

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	for all large scale industrial emitters of atmospheric carbon, including biomass and solid waste burning energy producing facilities.	
173. World Wildlife Fund on behalf of Eastern Mennonite University Creation Care Council, Emory and Henry College, Hollins University, Lynchburg College, Randolph College, Washington and Lee University	As academic institutions, we understand the importance of reducing carbon pollution and the opportunities provided by clean energy. Colleges and universities are committing to reduce their carbon footprint and increase the use of clean energy, because it is the right thing to do and because it makes business sense. Eleven Virginia colleges and universities have committed to becoming fully carbon neutral no later than 2050. Clean energy allows us to save money, hedge against volatile fossil fuel prices, and lock in predictable energy prices. Market-based carbon-reduction initiatives have been highly effective in reducing electric-sector GHG emissions while fostering economic growth and spurring innovation in clean energy technology. We recognize the importance of strong, stable policies that aim to account for the cost of carbon emissions and provide market certainty, allowing colleges and universities to plan and invest for the future. In Virginia, the proposed carbon reduction program would incentivize investments in renewable energy and energy efficiency--creating good-paying jobs for our graduates and others across the state, attracting world-class students, faculty, and staff to our institutions, improving the well-being of our communities, and making Virginia an even more attractive place to live and work. The regulation will be beneficial for Virginia's economy as a whole. This smart initiative will grow Virginia's nascent clean energy industry, help the state stay competitive, reduce energy costs, and improve the resiliency of our electrical grid. It will help utilities transition to a cleaner electric grid while offering more options for higher education institutions, businesses, and residents to access cost-competitive renewable energy. Our institutions value an affordable, reliable, and clean electricity supply, and we commend the Northam Administration for its commitment to lead Virginia in the transition to a low-carbon economy. We appreciate the many months of compiled research and feedback the previous administration gathered from energy stakeholders to develop forward-thinking carbon reduction measures. Steady carbon reduction policies will signal that Virginia is committed to embracing clean energy innovation, allowing institutions like ours to thrive for years to come.	Support for the proposal is appreciated. DEQ agrees that the program will benefit the state's economy while reducing carbon pollution and its negative impacts on health and welfare.

Public Participation

Please include a statement that in addition to any other comments on the regulatory change, the agency is seeking comments on the costs and benefits of the regulatory change and the impacts of the regulated community. Also, indicate whether a public hearing will be held to receive comments.

In addition to any other comments on the regulatory proposal, the board is seeking comment on the costs and benefits of the revisions to the proposal, the potential impacts of the revisions to the proposal and any impacts of the revisions on farm and forest land preservation. Also, the board is seeking information on impacts of the revisions on small businesses as defined in § 2.2-4007.1 of the Code of Virginia. Information may include 1) projected reporting, recordkeeping and other administrative costs, 2) probable effect of the regulation on affected small businesses, and 3) description of less intrusive or costly alternative methods of achieving the purpose of the regulation.

The department is seeking comment on whether 9VAC5-140-6050 C 1 should be amended to specify that the total CO_2 emissions related to CO_2 allowances only includes emissions resulting from the combustion of fossil fuel. Specifically, the department seeks input as to whether such an amendment to the standard requirements would provide clarity and consistency with the fossil fuel-focus of EO 11, or if such an amendment would be redundant because "fossil fuel-fired" is already defined in 9VAC5-140-6020 C and referenced in 9VAC5-140-6040 A, and is not needed to assure limitation of the rule to fossil fuel-fired facilities.

The Governor encourage comments is how to treat CO_2 emissions from CO_2 budget units that do not combust fossil fuels exclusively.

Anyone wishing to submit written comments for the public comment file may do so by mail, email or fax to the agency contact: Karen G. Sabasteanski, Policy Analyst, Office of Regulatory Affairs, Department of Environmental Quality, P.O. Box 1105, Richmond, Virginia, 23218 (email karen.sabasteanski@deq.virginia.gov, fax 804-698-4510). Comments may also be submitted through the Public Forum feature of the Virginia Regulatory Town Hall web site at: http://www.townhall.virginia.gov. Written comments must include the name and address of the commenter. In order to be considered, comments must be received by 11:59 pm on the last day of the public comment period.

A public hearing will not be held following the publication of this stage of this regulatory action.

Detail of Changes

Please list all regulatory changes and the consequences of the changes. Explain the new requirements and what they mean rather than merely quoting the text of the regulation.

If the regulatory change will be a new chapter, describe the intent of the language and the expected impact. Please describe the difference between existing regulation(s) and/or agency practice(s) and what is being proposed in this regulatory change. Delete inapplicable tables.

If the regulatory change is intended to replace an emergency regulation, please follow the instructions in the text following the three chart templates below. Please include citations to the specific section(s) of the regulation that are changing.

Detail of changes made since the previous (original proposal) stage:

Current chapter-section number	New chapter-section number, if applicable	New requirement from previous stage	Updated new requirement since previous stage	Change, intent, rationale, and likely impact of updated requirements

None	Article 1	CO_2 Budget Trading Program General Provisions	--	--
None	9VAC5-140-6010	Purpose	Amended to state that the rule is to be effected in a manner protective of health and the environment.	Needed for clarity.
None	9VAC5-140-6020 C	Definition of "allocate"	Amended to reflect relocation and renumbering of DMME provisions (see 9VAC5-140-6211).	Needed for clarity.
None	9VAC5-140-6020 C	Definition of "allowance"	Deleted.	Replaced with the new term "CO_2 allowance." Needed to ensure the proper functioning of the RGGI allowance market.
None	9VAC5-140-6020 C	Definition of "alternate CO_2 authorized account representative"	Deleted.	Needed in order to be consistent with new RGGI terminology.
None	9VAC5-140-6020 C	Definition of "CO_2 allowance"	Added.	Replacing "allowance." Needed to ensure the proper functioning of the RGGI allowance market
None	9VAC5-140-6020 C	Definition of "CO_2 authorized alternate account representative"	Added.	Needed in order to be consistent with new RGGI terminology.
None	9VAC5-140-6020 C	Definition of "CO_2 Budget Trading Program"	Amended.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "CCR allowance"	Amended to indicate that the CCR allowance is conditional.	Needed for clarity.
None	9VAC5-140-6020 C	Definition of "CO_2 CCR trigger price"	Amended to include the correct prices.	Needed in order for the program to operate properly.
None	9VAC5-140-6020 C	Definition of "CO_2 ECR trigger price"	Amended to include the correct prices.	Needed in order for the program to operate properly.
None	9VAC5-140-6020 C	Definition of "CO_2 offset allowance"	Added.	Needed in order for offsets from other states to be recognized.
None	9VAC5-140-6020 C	Definition of "conditional allowance"	Amended to clarify the relationship between a conditional allowance and a CO_2 allowance.	Needed in order for the program to operate properly.
None	9VAC5-140-	Definition of	Added.	Needed for clarity and in

	6020 C	"conditional CCR allowance"		order for the program to operate properly.
None	9VAC5-140-6020 C	Definition of "consignment auction"	Amended to refer to the correct auction entity.	Needed for clarity.
None	9VAC5-140-6020 C	Definition of "fossil fuel-fired"	Amended to change the amount of fuel comprised of fossil fuel from 10% to 5%.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "maximum design heat input"	Deleted.	This term is not used in the proposal and must be removed.
None	9VAC5-140-6020 C	Definition of "minimum reserve price"	Amended to change the price from $2.00 to $2.32.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "receive"	Amended to be more specific.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "RGGI, Inc."	Deleted.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "state"	Deleted.	Needed in order for clarity. "Participating state" replaces this more general term.
None	9VAC5-140-6020 C	Definition of "total useful energy"	Added.	Needed in order for the industrial exemption (9VAC5-140-6040 B) to operate properly.
None	9VAC5-140-6020 C	Definition of "useful net thermal energy"	Added.	Needed in order for the industrial exemption (9VAC5-140-6040 B) to operate properly.
None	9VAC5-140-6030	Measurements, abbreviations and acronyms.	Unused terms removed.	Needed for clarity.
None	9VAC5-140-6040 B	Applicability.	Amended to clarify industrial facilities exempt from the rule.	Needed to address third-party industrial suppliers while maintaining consistency with the RGGI Model Rule.
None	9VAC5-140-6050 C 1	CO_2 requirements, holding allowances for compliance		The department is seeking comment on whether an amendment is needed to 9VAC5-140-6050 C 1 to specify that the total CO_2 emissions related to CO_2 allowances only includes

				emissions resulting from the combustion of fossil fuel.
None	Article 2	CO_2 Authorized Account Representative for CO_2 Budget Sources.	--	--
None	9VAC5-140-6090	Alternate CO_2 authorized account representative.	The term "alternate CO_2 authorized account representative" is amended to "CO_2 authorized alternate account representative."	Needed in order to be consistent with new RGGI terminology.
None	9VAC5-140-6100	Changing the CO_2 authorized account representatives and the alternate CO_2 authorized account representative; changes in the owners and operators.	The term "alternate CO_2 authorized account representative" is amended to "CO_2 authorized alternate account representative."	Needed in order to be consistent with new RGGI terminology.
None	9VAC5-140-6110	Account certificate of representation.	The term "alternate CO_2 authorized account representative" is amended to "CO_2 authorized alternate account representative."	Needed in order to be consistent with new RGGI terminology.
None	9VAC5-140-6130	Delegation by CO_2 authorized account representative and alternate CO_2 authorized account representative.	The term "alternate CO_2 authorized account representative" is amended to "CO_2 authorized alternate account representative." In subsection H, "must" has been changed to "shall."	Needed in order to be consistent with new RGGI terminology, and to reflect correct regulatory style.
None	Article 5	CO_2 Allowance Allocations	--	--
None	9VAC5-140-6190 A	Base budgets.	The initial CO_2 base budget has been set at 28 million tons, declining by 3% per year through 2030.	Needed in order to realize the program goal of reducing carbon pollution at a certain rate of a specified time period.
None	9VAC5-140-6190 C	Base budgets.	Amended to establish specific post-2030 adjustments.	Needed to ensure continuing compliance into the future.
None	9VAC5-140-	Undistributed and	Amended to correct	Needed for clarity and in

	6200	unsold CO_2 allowances.	the term "conditional allowance" and to replace "may" with "will."	order for the program to operate properly.
None	9VAC5-140-6210 A	CO_2 allowance allocations.	Amended to clarify the allocation of allowances.	Needed for clarity.
None	9VAC5-140-6210 B	CO_2 allowance allocations.	DMME provisions have been moved to a separate new section (9VAC5-140-6211); succeeding sections renumbered accordingly.	Needed for clarity.
None	9VAC5-140-6210 ~~D~~ C	CO_2 allowance allocations.	Amended to more clearly explain how the CCR allowances will be allocated, including a new equation for calculating the pro rata distribution of CCR allowances.	Needed for clarity and in order for the program to operate properly.
None	9VAC5-140-6210 ~~E~~ D	CO_2 allowance allocations.	Amended to more clearly explain how the ECR allowances will be allocated.	Needed for clarity and in order for the program to operate properly.
None	9VAC5-140-6210 ~~F~~ E	CO_2 allowance allocations.	Minor corrections.	Needed for clarity.
None	9VAC5-140-6210 ~~I~~ H	CO_2 allowance allocations.	Timing requirements amended in order to provide more detail as to how and when conditional allowances will be allocated.	Needed for clarity.
None	9VAC5-140-6210 I	None.	New subsection added to clarify that implementation of the CCR, ECR and banking adjustment will depend on the extent of the CO_2 trading program.	Needed for clarity.
None	9VAC5-140-6211	None.	Section added for DMME provisions moved from 9VAC5-140-6040 A 2.	Needed for clarity.
None	Article 6	CO_2 Allowance Tracking System	--	--
None	9VAC5-140-6230	Establishment of accounts.	The term "alternate CO_2 authorized account representative" is amended to "CO_2	Needed in order to be consistent with new RGGI terminology.

			authorized alternate account representative."	
None	9VAC5-140-6260 A 3	Compliance.	Amended in order for Virginia to recognize offsets generated by other RGGI states.	Needed in order to participate in the RGGI program.
None	Article 8	Monitoring, Reporting and Recordkeeping	--	--
None	9VAC5-140-6330 A	General requirements.	Minor correction.	Needed for clarity.
None	Article 9	Auction of CO_2 CCR and ECR allowances	--	--
None	9VAC5-140-6430	Consignment auction.	Amended to indicate that one quarter of the annual conditional allowance allocation will be consigned by the CO_2 budget source or the holder of a public contract with DMME to each auction. At the completion of the consignment auction, a conditional allowance sold at auction becomes a CO_2 allowance.	Needed for clarity and in order for the program to operate properly.
None	9VAC5-140-6435	None.	New section added to enable the use of a direct auction without consignment in accordance with requirements established by the Virginia General Assembly.	Needed in order for the program to operate properly in the event of a legislative requirement.
None	Article 10	Program Monitoring and Review	--	--
None	9VAC5-140-6440	None.	Article added.	Specifies that in conjunction with program monitoring and review, impacts specific to Virginia will be evaluated, including economic, energy and environmental impacts, and impacts on vulnerable and environmental justice communities. Needed in order to clarify that these specific impacts will be monitored and evaluated.

Compendium of all new provisions:

New chapter-section number	New requirements	Other regulations and law that apply	Intent and likely impact of proposed requirements
Article 1	CO_2 Budget Trading Program General Provisions	--	--
9VAC5-140-6010	Purpose	None.	Establishment of the Virginia component of the CO_2 Budget Trading Program. Needed to provide clarity.
9VAC5-140-6020	Definitions	None.	Terms defined. Needed to assure that the regulation is understood and will operate properly.
9VAC5-140-6030	Measurements, abbreviations and acronyms.	None.	Needed to assure that the regulation is understood and will operate properly.
9VAC5-140-6040	Applicability		Defines sources to which the regulation applies. Needed in order that the regulation apply to certain affected sources. Implementation of this regulation will have an impact on those sources that are directly subject to the requirements of the rule.
9VAC5-140-6050	Standard requirements	None.	General requirements for permits, monitoring, holding and management of CO_2 allowances, excess emissions, recordkeeping and reporting, and liability. Needed in order for the program to operate properly.
9VAC5-140-6060	Computation of time	None.	How to define the beginning and ending of an activity. Needed in order for the program to operate properly.
9VAC5-140-6070	Severability	None.	Clarifies that the remainder of rule is not rendered invalid by the invalidity of another part of the rule. Needed in order for the program to operate properly.
Article 2	CO_2 Authorized Account Representative for CO_2 Budget Sources	--	--
9VAC5-140-6080	Authorization and responsibilities of the CO_2 authorized account representative	None.	Details how this individual is selected and authorized, and their key roles. Needed in order for the program to operate properly.
9VAC5-140-6090	Alternate CO_2 authorized account representative	None.	Details how this individual is selected and authorized, and their key roles. Needed in order for the program to operate properly.

9VAC5-140-6100	Changing the CO_2 authorized account representatives and the alternate CO_2 authorized account representative; changes in the owners and operators	None.	How changes are made to account representatives, and owners and operators. Needed in order for the program to operate properly.
9VAC5-140-6110	Account certificate of representation	None.	How account representatives are to be certified. Needed in order for the program to operate properly.
9VAC5-140-6120	Objections concerning the CO_2 authorized account representative	None.	How to deal with any disputes relevant to the account representative. Needed in order for the program to operate properly.
9VAC5-140-6130	Delegation by CO_2 authorized account representative and alternate CO_2 authorized account representative	None.	Enables the account representatives to delegate their authority to other persons. Needed in order for the program to operate properly.
Article 3	Permits		
9VAC5-140-6140	General CO_2 budget permit requirements	None.	References pertinent permitting regulations. Needed to assure that existing permitting requirements are met.
9VAC5-140-6150	Submission of CO_2 budget permit applications	None.	Requires a budget permit application by a certain date. Needed in order for the program to operate properly.
9VAC5-140-6160	Information requirements for CO_2 budget permit applications	None.	Lists elements concerning the CO_2 budget source for which the application is submitted. Needed in order for the program to operate properly.
Article 4	Compliance Certification		
9VAC5-140-6170	Compliance certification report	None.	Requires the source to certify whether each CO_2 budget unit was operated in compliance with the requirements of the CO_2 Budget Trading Program. Needed in order for the program to operate properly.
9VAC5-140-6180	Action on compliance certifications	None.	Explains how the compliance certification is reviewed. Needed in order for the program to operate properly.
Article 5	CO_2 Allowance Allocations		
9VAC5-140-6190	Base budgets	None.	Base budgets are established from 2020 onward. In the original proposal, the board sought comment on whether the initial Virginia CO_2 Budget Trading Program base budget for 2020 should be 33 million tons or 34

			million tons, and declining accordingly by 3% per year. Needed to effect the carbon pollution reduction that ED 11 require of this regulation.
9VAC5-140-6200	Undistributed and unsold CO_2 allowances	None.	Explains how the department may retire undistributed and unsold allowances. Needed for the program to operate properly.
9VAC5-140-6210	CO_2 allowance allocations	None.	Describes how the department will allocate allowances. CCR and ECR allowances as described in Tables 140-5A and B are tied to the 2020 base budget and as such the board is seeking comment as to whether these numbers should be tied to a base budget of 33 million tons or 34 million tons. Needed to effect the carbon pollution reduction that ED 11 requires of this regulation.
9VAC5-140-6211	CO_2 allowance allocations, DMME allowances	None.	Requires that 5% of the base or adjusted budget allowances be allocated to DMME. Needed in order to assure the development of programs that lower electricity demand and reduce the cost of the program.
9VAC5-140-6215	CO_2 allocation methodology		Describes the methodology for allocating allowances using net electric output. Needed for the program to operate properly.
Article 6	CO_2 Allowance Tracking System	--	--
9VAC5-140-6220	CO_2 Allowance Tracking System accounts	None.	Establishes a system in order for tracking compliance accounts. Needed in order for the program to operate properly.
9VAC5-140-6230	Establishment of accounts	None.	Explains how compliance accounts are established and managed. Needed in order for the program to operate properly.
9VAC5-140-6240	CO_2 Allowance Tracking System responsibilities of CO_2 authorized account representative.	None.	Requires that all submissions pertaining to the account are made only by the authorized account representative. Needed in order for the program to operate properly.
9VAC5-140-6250	Recordation of CO_2 allowance allocations	None.	Describes how the department records allowances. Needed in order for the program to operate properly.
9VAC5-140-6260	Compliance	None.	CO_2 allowances that meet certain criteria are available to be

			deducted in order for a source to comply with the CO_2 requirements for a control period. Needed in order for the program to operate properly.
9VAC5-140-6270	Banking	None.	Requires that CO_2 allowances remain in account until deducted or transferred. Needed in order for the program to operate properly.
9VAC5-140-6280	Account error	None.	Allows corrections to be made. Needed in order for the program to operate properly.
9VAC5-140-6290	Closing of general accounts	None.	Describes how to close an account. Needed in order for the program to operate properly.
Article 7	CO_2 Allowance Transfers	--	--
9VAC5-140-6300	Submission of CO_2 allowance transfers	None.	Specifies how to submit transfers. Needed in order for the program to operate properly.
9VAC5-140-6310	Recordation	None.	Describes the recordation of transfers. Needed in order for the program to operate properly.
9VAC5-140-6320	Notification	None.	Explains notification of transfers to each party. Needed in order for the program to operate properly.
Article 8	Monitoring and Reporting	--	--
9VAC5-140-6330	General requirements	None.	Generally requires a source to comply with monitoring, recordkeeping and reporting requirements as provided in this regulation and 40 CFR Part 75. Needed to assure that all pertinent state and federal requirements are met.
9VAC5-140-6340	Initial certification and recertification procedures	None.	Facilities may be exempt under certain circumstances. Needed in order for the program to operate properly.
9VAC5-140-6350	Out-of-control periods	None.	What to do when a monitoring system fails to meet QA/QC or other requirements. Needed to assure compliance.
9VAC5-140-6360	Notifications	None.	Notification requirement. Needed in order for the program to operate properly.
9VAC5-140-6370	Recordkeeping and reporting	None.	Monitoring plan recordkeeping and reporting requirements. Needed to assure compliance.
9VAC5-140-6380	Petitions	None.	How to request approval for an alternative to any requirement of 40 CFR Part 75. Needed to assure compliance.
9VAC5-140-6390	Reserved	None.	

9VAC5-140-6400	Additional requirements to provide output data	None.	Additional steps to be taken when determining output. Needed in order for the program to operate properly.
Article 9	Auction of CO_2 CCR and ECR allowances	--	--
9VAC5-140-6410	Purpose	None.	General purpose of the article. Needed to provide clarity.
9VAC5-140-6420	General requirements	None.	Describes information required in the auction notice, rules for sale of allowances, information on the reserve price, and withholding ECR allowances from an auction. Needed in order for the auction to operate.
9VAC5-140-6430	Consignment auction	None.	How conditional allowances are auctioned at consignment and converted to allowances used for compliance. Needed in order for the auction to operate.
9VAC5-140-6435	Other auction	None.	Allows participation in a direct auction if permitted by the General Assembly. Needed in the event a direct auction is required.
Article 10	Program Monitoring and Review	--	--
9VAC5-140-6440	Program monitoring and review	None.	Requires evaluation of program impacts specific to Virginia, including impacts on environmental justice communities. Needed to monitor impacts on Virginia and certain communities.

REG\DEV\C17-04TP-2

Attachment 11

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Final Regulation
Agency Background Document

Agency name	State Air Pollution Control Board
Virginia Administrative Code (VAC) citation(s)	Part VII, 9VAC5-140
Regulation title(s)	Regulation for Emissions Trading
Action title	Establish a new regulation to reduce and cap carbon dioxide (CO_2) from fossil fuel-fired electric power generating facilities by means of an interstate trading program (Revision C17)

This information is required for executive branch review and the Virginia Registrar of Regulations, pursuant to the Virginia Administrative Process Act (APA), Executive Order 14 (as amended, July 16, 2018), the Regulations for Filing and Publishing Agency Regulations (1 VAC7-10), and the *Virginia Register Form, Style, and Procedure Manual for Publication of Virginia Regulations.*

Brief Summary

Please provide a brief summary (preferably no more than 2 or 3 paragraphs) of this regulatory change (i.e., new regulation, amendments to an existing regulation, or repeal of an existing regulation). Alert the reader to all substantive matters. If applicable, generally describe the existing regulation.

The State Air Pollution Control Board adopted a proposed regulation to establish the Virginia CO_2 Budget Trading Program. The regulation, as originally proposed, included provisions to (i) implement a declining cap on carbon emissions and establish an allowance that will be issued for each ton of carbon emitted by an electricity generating facility, which can then decide whether to reduce carbon emissions and sell the resulting additional allowances or not reduce carbon emissions and make up the difference with purchased allowances; (ii) establish a consignment auction as the mechanism for determining the cost of allowances; (iii) provide that a cost containment reserve allowance will be offered for sale at an auction for the purpose of containing the cost of CO_2 allowances in the event of higher than anticipated emission reduction costs and that an emission containment reserve allowance will be withheld from sale at an auction for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs; (iv) implement monitoring, recording, and recordkeeping requirements; and (v) allocate conditional allowances to the Department of Mines, Minerals and Energy.

Since publication of the proposed regulation in 34:10 VA.R. 924-959 January 8, 2018, the board revised the original proposal, which included two options on the base budget of 33 and 34 million tons. The board approved a new base budget of 28 million tons based on new modeling and other information. The new

base budget of 28 million tons will determine, based on a 3.0% annual reduction, the annual budgets and allocations for future years. These requirements apply to fossil fuel-fired electric generating facilities.

Other substantive changes in the re-proposed action include (i) the recognition of offsets from other participating states, (ii) clarification of the exemption of fossil fuel units from CO_2 accounting, (iii) a more detailed description of exempt industrial sources, (iv) a more detailed description of how the cost containment reserve will be managed, (v) a new section allowing for participation in a non-consignment auction, and (vi) a new section requiring program monitoring and review.

Acronyms and Definitions

Please define all acronyms used in the Agency Background Document. Also, please define any technical terms that are used in the document that are not also defined in the "Definition" section of the regulations.

ACE - Affordable Clean Energy Rule
CCR - Cost Containment Reserve
CFB - circulating fluidized bed technology
CHP - combined heat and power
CO_2 - carbon dioxide
CPP - Clean Power Plan
CSAPR - Cross-State Air Pollution Rule
CSP - competitive service provider
DEQ - Department of Environmental Quality
DMME - Department of Mines, Minerals and Energy
ECR - Emissions Containment Reserve
EGU - electric generating unit
ED 11 - Executive Directive 11
EJ - environmental justice
EO 57 - Executive Order 57
EPA - U.S. Environmental Protection Agency
GHG - greenhouse gas
GTSA - Grid Transformation and Security Act
GW - gigawatt
IOU - investor owned utility
IPM - Integrated Planning Model
IRP - Integrated Resource Plan
MW - megawatt
MWh - megawatt hour
NAAQS - National Ambient Air Quality Standards
NGCC - natural gas-fired combined cycle
NO_X - nitrogen oxides
PJM - PJM Interconnection
PM - particulate matter
PSD - Prevention of Significant Deterioration
RGGI - Regional Greenhouse Gas Initiative
SCC - State Corporation Commission
SO2 - sulfur dioxide
VRE - voluntary renewable set-aside
WCI - Western Climate Initiative
WHP - waste heat to power

Statement of Final Agency Action

Please provide a statement of the final action taken by the agency including: 1) the date the action was taken; 2) the name of the agency taking the action; and 3) the title of the regulation.

On April 19, 2019, the State Air Pollution Control Board took final action to amend the Regulation for Emissions Trading by adopting a new regulation, "CO_2 Budget Trading Program" (Part 7 of 9VAC5-140). The regulatory action is to be effective as provided in the Administrative Process Act.

Mandate and Impetus

Please list all changes to the information reported on the Agency Background Document submitted for the previous stage regarding the mandate for this regulatory change, and any other impetus that specifically prompted its initiation. If there are no changes to previously-reported information, include a specific statement to that effect.

There are no changes to previously reported information known to the agency.

Legal Basis

Please identify (1) the agency or other promulgating entity, and (2) the state and/or federal legal authority for the regulatory change, including the most relevant citations to the Code of Virginia or Acts of Assembly chapter number(s), if applicable. Your citation must include a specific provision, if any, authorizing the promulgating entity to regulate this specific subject or program, as well as a reference to the agency or promulgating entity's overall regulatory authority.

Section 10.1-1308 of the Virginia Air Pollution Control Law (Title 10.1, Chapter 13 of the Code of Virginia) authorizes the State Air Pollution Control Board to promulgate regulations abating, controlling and prohibiting air pollution in order to protect public health and welfare. Written assurance from the Office of the Attorney General that the State Air Pollution Control Board possesses the statutory authority to promulgate the proposed regulation amendments is available upon request.

Promulgating Entity

The promulgating entity for this regulation is the State Air Pollution Control Board.

State Requirements

Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia's Clean Energy Economy," directs the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10.1-1300 et seq., and Virginia Code § 2.2-4000, et seq.:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit CO_2 from electric power facilities that:

a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of CO_2 allowances through a multi-state trading program; and

b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on CO_2 emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10.1-1308.

Purpose

Please explain the need for the regulatory change, including a description of: (1) the rationale or justification, (2) the specific reasons the regulatory change is essential to protect the health, safety or welfare of citizens, and (3) the goals of the regulatory change and the problems it's intended to solve.

The regulation is needed to control CO_2 emissions in order to protect the public's health and welfare. The proposed regulation is being developed in order to meet the direction of Governor McAuliffe's Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia's Clean Energy Economy," which states:

There is no denying the science and the real-world evidence that climate change threatens the Commonwealth of Virginia, from our homes and businesses to our critical military installations and ports. Rising storm surges and flooding could impact as many as 420,000 properties along Virginia's coast that would require $92 billion of reconstruction costs.

The challenges and costs of bolstering resilience and minimizing risk are too great for any locality to bear alone. While the impacts are significant, there are technologies in the clean energy sector that could help mitigate these impacts while simultaneously creating jobs in twenty-first century industries. The number of solar jobs in Virginia has grown by 65 percent in the last year alone, and Virginia is now the ninth fastest growing solar jobs market in the country. Revenue for clean energy businesses in Virginia has increased from $300 million in 2014 to $1.5 billion in 2016. Through state leadership, Virginia can face the threats of climate change head on and do so in a way that makes clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio.

With these considerations in mind, I issued Executive Order 57 (EO 57) on June 28, 2016. Under EO 57, I directed the Secretary of Natural Resources to convene a work group to study and recommend methods to reduce carbon dioxide emissions from electric power facilities and grow the clean energy economy within existing state authority. The group consisted of the Secretary of Natural Resources, the Secretary of Commerce and Trade, the Director of the Virginia Department of Environmental Quality, the Director of the Virginia Department of Mines, Minerals and Energy, and the Deputy Attorney General for Commerce, Environment, and Technology. This group facilitated extensive stakeholder engagement over the last year, including six in-person meetings and a ninety-day public comment period, before compiling its recommendations and submitting a final report to me on May 12, 2017.

Among the most significant recommendations from the group is the need to develop regulations limiting the total amount of carbon dioxide emitted from electric power facilities. Given the nature of the climate change threat and the promise of clean energy solutions, I agree with this recommendation.

Accordingly, pursuant to the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10. 1-1300, et seq. and Virginia Code § 2.2-4000, et seq.:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that:

a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and

b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10. 1-1308.

Additionally, Executive Order 57 Work Group's "Report and Final Recommendations to the Governor" states that:

> The Work Group received a number of presentations and written comments from stakeholders advocating for a regulation to limit carbon dioxide from power plants. These comments included recommendations that the Commonwealth join or participate in the Regional Greenhouse Gas Initiative (RGGI) or another regional trading program, that a price be put on carbon, and that Virginia strive to reduce its greenhouse gases by 30 to 40 percent by the year 2030. . . . Although many stakeholders provided feedback focused on specific in-state targets (such as 30x30), the Work Group believes that it is important and necessary that Virginia work through a regional model, like the established and successful RGGI, in order to achieve lower compliance costs and address the interstate nature of the electric grid.

The Work Group recommends that the Governor consider taking action via a regulatory process to establish a "trading-ready" carbon emissions reduction program for fossil fuel fired electric generating facilities that will enable participation in a broader, multi-state carbon market. DEQ has addressed the issue of how to participate in a regional trading program by working with RGGI because as of this writing, RGGI is the only practicable regional trading program with which Virginia can participate. Given the need to establish a mechanism for an emissions trading program, consideration of the RGGI program is appropriate; however, the draft proposal does not limit Virginia's participation to RGGI.

Substance

Please briefly identify and explain the new substantive provisions, the substantive changes to existing sections, or both. A more detailed discussion is provided in the "Detail of Changes" section below.

1. The primary purpose of the regulation is to implement a declining cap on carbon emissions. The administrative means of accomplishing this will be effected by linking Virginia to RGGI, which is an established emissions trading program. An allowance will be issued for each ton of carbon emitted by an electricity generating facility. The company must then decide if it will reduce carbon emissions and sell the resulting additional allowances, or if it will not reduce carbon emissions and make up the difference with purchased allowances. The original proposal included two options on the base budgets, 33 million tons and 34 million tons. The board selected 28 million tons, which will determine, based on a 3% annual reduction, the annual budgets and allocations for future years.

2. The mechanism for determining the cost of allowances will be a consignment auction.

3. A cost containment reserve allowance will be offered for sale at an auction for the purpose of containing the cost of CO_2 allowances in the event of higher than anticipated emission reduction costs. An emission containment reserve allowance will be withheld from sale at an auction for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.

4. Monitoring, recording, and recordkeeping requirements will be implemented to track compliance.

5. Conditional allowances will be allocated to the Department of Mines, Minerals and Energy (DMME) in order to assist the department for the abatement and control of air pollution, specifically, CO_2.

6. In conjunction with program monitoring and review, impacts specific to Virginia will be evaluated, including economic, energy and environmental impacts, and impacts on vulnerable and environmental justice communities.

Issues

Please identify the issues associated with the regulatory change, including: 1) the primary advantages and disadvantages to the public, such as individual private citizens or businesses, of implementing the new or amended provisions; 2) the primary advantages and disadvantages to the agency or the

Commonwealth; and 3) other pertinent matters of interest to the regulated community, government officials, and the public. If there are no disadvantages to the public or the Commonwealth, include a specific statement to that effect.

1. Public: The primary advantage to the public would be health and welfare benefits associated with controlling carbon pollution. The program is designed to avoid any significant economic impacts.

2. Department: No significant advantages or disadvantages to the department have been identified. There may be a minor impact in terms of administering a new program.

Requirements More Restrictive than Federal

Please list all changes to the information reported on the Agency Background Document submitted for the previous stage regarding any requirement of the regulatory change which is more restrictive than applicable federal requirements. If there are no changes to previously-reported information, include a specific statement to that effect.

There are no applicable federal requirements. DEQ notified the Senate Agriculture, Conservation and Natural Resources Committee, the Senate Commerce and Labor Committee, the House of Delegates Agriculture, Chesapeake and Natural Resources Committee, and House of Delegates Commerce and Labor Committee of this regulatory action in November 2017.

Agencies, Localities, and Other Entities Particularly Affected

Please list all changes to the information reported on the Agency Background Document submitted for the previous stage regarding any other state agencies, localities, or other entities that are particularly affected by the regulatory change. If there are no changes to previously-reported information, include a specific statement to that effect.

There are no changes to previously reported information known to the agency.

Public Comment

Please summarize all comments received during the public comment period following the publication of the previous stage, and provide the agency response. Ensure to include all comments submitted: including those received on Town Hall, in a public hearing, or submitted directly to the agency or board. If no comment was received, enter a specific statement to that effect.

Comments received during the initial public comment period (January 8 through April 9, 2018):

Commenter	Comment	Agency response
1. About 155 individual commenters	General support for the proposal was expressed.	Support for the proposal is appreciated.
2. About 415 emails, cards and petition sponsored by Faith Alliance	Climate disruption poses increasing threats to Virginians' public health, national security, environment and economy. Virginia has joined states, cities and counties across the country that understand all levels of government must act on climate if we are to protect our	Support for the proposal is appreciated. Specific issues identified by the commenters are discussed in further detail below.

for Climate Solutions and Interfaith Power and Light; petition sponsored by Virginia Chapter of the Sierra Club, 2717 signatures	communities in light of the Trump administration's continued attacks on environmental protections. I support setting the strongest possible standard to cut Virginia emissions from power plants through participation in a carbon market. This is a critically important step toward carbon pollution reductions. I request that DEQ use its authority to adopt and implement a final standard that caps and reduces carbon pollution as rapidly as possible, beginning as soon as possible. The 2020 base year should be less than 33 million tons. Cover carbon pollution from biomass, which can be worse than energy generated by fossil fuels. Set the expectation of continued carbon reductions after 2030. Monitor implementation in order to respond to disproportionate environmental burden experienced by front-line, low-income and vulnerable communities.	
3. About 550 sponsored emails and Town Hall comments	I am thrilled to see that the board has approved draft regulations to cap carbon emissions. Without immediate and bold action, climate change will present unprecedented challenges to our coastal communities and would harm communities of color at a much higher rate than others. I support a final carbon rule that has the strongest possible cap on carbon emissions from Virginia's power plants through a carbon market. I also support supplemental legislation that would allow Virginia to invest a portion of the carbon market revenue in coastal resilience. The 2020 base year emissions cap should be between 30 and 32 million tons. The cap should cover biomass facilities, which can be worse for the climate than fossil fuel power plants. Carbon emission reductions past 2030 should be addressed. The plan should address the needs of low-income and frontline communities by establishing implementation monitoring and rapid response guidelines that can detect any instances of disproportionate environmental burdens.	Support for the proposal is appreciated. Specific issues identified by the commenters are discussed in further detail below.
4. About 45 sponsored emails and Town Hall comments	I'm writing to voice my support of a regulation that cuts carbon pollution from power plants and allows us to trade carbon allowances with other states. With no help coming from the federal level in addressing climate change, it's up to Virginia to act. By cutting carbon emissions in Virginia, we have the opportunity to protect public health and safety while creating jobs in the carbon-neutral renewable energy and energy efficiency sectors. And because we're joining a coalition of other states with carbon caps, action we take in Virginia is greater than the sum of its parts. Carbon trading also creates the opportunity to bring revenue back to the state to aid in clean energy deployment and resiliency, money we shouldn't leave on the table or gift to our utilities. I urge you to proceed with a strong regulation that shows Virginia is a leader in addressing climate change and takes its responsibility seriously.	Support for the proposal is appreciated.
5. 4 emails	I support Governor Northam's Clean Energy Virginia Initiative. To address the threat of climate change to our	Support for the proposal is appreciated.

	coast and public health, the state must reduce pollution from fossil fuel-fired power plants and expand renewable energy. The initiative calls for a 30% reduction in carbon emissions by 2030 and will enable Virginia to trade carbon allowances with 9 other states, a market-based mechanism that will bring revenue back to Virginia while also cutting harmful air pollution. That is why I urge the board to adopt the plan to fight climate change, protect health, and create economic growth.	
6. 5 emails	I am profoundly proud Virginia is preparing an initiative to reduce carbon and other toxic pollutants from utility power plants. Yet, how Virginia implements this program is critical to its success. And I expect success. A successful plan will: improve public health, expand clean energy development, save all electric customers money and improve our state's competitiveness, protect living creatures and reduce climate change burdens on future generations of Virginians, ensure Virginia is "carbon trading ready," and require that baseline measures of carbon emissions be real and annual reductions be real and ambitious.	Support for the proposal is appreciated.
7. Petition sponsored by Natural Resources Defense Council (NRDC), 884 signatures	I urge DEQ to put a strong limit on carbon pollution and to reduce that pollution as rapidly as possible, in a way that grows the state's renewable energy economy and reduces energy bills through energy efficiency. Virginians are ready for strong action and we--along with future generations--applaud you for stepping up on climate and support your work to finalize a strong statewide carbon rule.	Support for the proposal is appreciated.
8. Petition sponsored by Virginia League of Conservation Voters (LCV), 1551 signatures	To address the climate change that threatens our coast and public health, Virginia must reduce pollution from fossil fuel-fired power plants and expand renewable energy. Governor Northam's Clean Energy Virginia Initiative is the solution for addressing climate change while growing Virginia's economy, reducing greenhouse gas (GHG) emissions, and protecting Virginias' air. The initiative calls for a 30% reduction in carbon emissions by 2030 and will enable Virginia to trade carbon allowances with 9 other states, a market-based mechanism that will bring revenue to Virginia while cutting harmful air pollution.	Support for the proposal is appreciated.
9. Petition sponsored by Environment Virginia, 207 signatures	From dozens of smog-ridden days to rising sea levels, Virginians are feeling the impacts of climate change. Virginia needs to move forward with plans to protect our communities from climate change and follow the steps that other states have taken to cut pollution while the federal government stalls. I request that DEQ adopt the strongest possible standard to cut carbon emissions by ensuring that Virginia cuts carbon pollution as quickly and as soon as possible. The 2020 emissions cap should be between 30 and 32 million tons. This cap should mirror the cap that states in RGGI, the nation's most successful regional climate program, are taking to reduce emissions 30% by 2030. The rule should set the expectation that carbon pollution will continue to be	Support for the proposal is appreciated. Specific issues identified by the commenters are discussed in further detail below.

	reduced after 2030. This standard should take into account Virginia's untapped energy efficiency potential and all planned renewable energy developments in Virginia.	
10. Gianluigi Ciovati	I encourage a base budget of 33 million tons, and applicability to all fossil fuel power generating units. I request DEQ to include biomass into the fossil fuel category as recent expansion of such power generating units highlighted the issues of the long timeframe required to capture the emitted CO_2 by re-forestation and that, in order to meet increasing demand, not all the material used to make the fuel comes from waste but from an increasing fraction is coming from tree logging. The regulation should result in a greater economic benefit than cost: energy efficiency is the lowest cost resource to reduce CO_2 pollution while meeting energy demand. Dominion ranks 50th in efficiency efforts among the 51 largest electric utilities in the nation. Strong energy efficiency policies would result in close to 40,000 new jobs by 2030. More jobs are predicted to be created by further increase in true renewable energy sources such as wind and solar. As the disruptive effects of climate change are becoming more evident, the risk and the cost of inaction on reducing CO_2 emission is too high and the regulation is a positive step in the right direction.	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.
11. Virginia Clean Cities (VCC)	Regulation of carbon emissions is critically important for Virginia, a coastal state with a wide distribution of energy sources. VCC is an alternative fuel vehicle coalition, working with governments at state, regional, local, and federal level with businesses and vehicle operators in an effort to reduce GHG emissions in transportation. While Virginia's largest source of CO_2 and GHGs is the transportation sector, we recognize the value of reviewing our existing electricity portfolio and working toward cleaner sources of domestic fuels. VCC strongly supports involvement in RGGI. Many RGGI states have advanced transportation projects to mitigate the significant GHGs from transportation. VCC include electric vehicles in our portfolio, as well as hydrogen, ethanol and natural gas vehicles all utilizing electricity from the grid in some manner. Further, by using cleaner domestic fuels such as biomass, natural gas, or renewable energy for Virginia's electricity, we can benefit our economy and move Virginia forward.	Support for the proposal is appreciated. Although the transportation sector is not directly addressed in this proposal, DEQ agrees that it is an important consideration in controlling carbon emissions.
12. B. Eli Fishpaw	It is a breath of fresh air that Virginia is embarking on an effort to reduce GHG from power production. Recognizing the measure of what causes climate change is essential to learning to live within the Carbon Cycle. Without active recognition that the license to emit carbon into the atmosphere must be limited, it is difficult to imagine meeting the challenge. We focus our efforts to address human caused climate change with an acceptance that excess carbon emissions (primarily CO_2) is the problem. Therefore, all solutions must have a goal of limiting carbon emissions to less than the amount	The information provided by the commenter is appreciated. The primary purpose of the regulation is to address carbon pollution via linking to RGGI in accordance with ED 11; therefore, no fee-and-dividend approach is being considered under this regulatory action.

	that can be sequestered out of the atmosphere. Most human carbon emissions are sequestered by nature. These emissions are in the Carbon Cycle. Under a Net Zero Carbon Emissions Economy, human emissions would equal the amount that can be sequestered. At this level, we stop adding CO_2 concentration to the atmosphere. However, we are not reducing the CO_2 concentration either. When our emissions are higher than what nature can sequester, the over emissions are added to past years over emissions. We need to limit our emissions to less than what can be sequestered to live in the carbon cycle. This must be understood before the policies that can meet the challenge are combined with a determined effort by the public to meet this challenge. The license to emit CO_2 into the atmosphere should be shared fairly. Using the data from 2007 IPCC on natural and human emissions, to achieve net zero (balanced budget) average per person emissions need to be limited to 2.6 tons CO_2/year. This would be a "Fair Share." At this level, all emissions are sequestered to achieve a Net Zero Carbon Emissions Economy. Cap and Trade allows emissions in exchange for supporting some activity that reduces CO_2 emissions, not from net zero, but from our historically high rate of emissions. In the proposal it provides financial support for high emissions electric production to reduce their emissions through technology. The cap and trade model for pricing carbon has the advantage of functioning in the background without asking sacrifice or understanding of the individual. Getting the public to understand that there is a demand by nature to limit to the amount of carbon emissions is essential to achieving it. Existing high emissions electric generation should not be rewarded by the entitlement license to emit that they can sell by reducing. I promote a continually escalating carbon tax with a rebate for the fair share of emissions and paying people to carbon capture and permanently store in the ground. A carbon tax can be similar to that proposed by Citizens Climate Lobby that charges a fee/ton CO_2 at the source and returns that fee equally to all citizens. By creating a modest fee, financial incentives are created for reducing energy and reward the development of renewable energy. As households and businesses evaluate future investments, their spreadsheets will show that investing in improvements offers the highest rate of return. This creates economic growth in the conservation, regeneration and renewable energy sectors. However, because all fees are redistributed equally, there is no money for sequestering carbon through technology. With a tax similarly structured, with a rebate for the tax on the Fair Share, creates funding for paying people to sequester carbon and preserving	

	existing inventories of terrestrial carbon such as mature forest. Biochar is a way of permanently capturing carbon through pyrolysis. Adding the resulting charcoal to the ground increases retention of moisture, micronutrients and microorganisms. I propose that we pay people to create biochar at half the current rate of the carbon tax. This will insure a net reduction in CO_2 for the whole process. As promising as this is, biochar is not substitute for reducing emissions.	
13. L. David Roper	Deploying wind energy and solar energy in the U.S. can supply the demand. Using time-of-day availability of solar, on-shore wind and off-shore wind power in the four U.S. time zones and reasonable values of availability, wind and solar power can closely supply the time-of-day demand for electricity. Modest battery storage can fill in the small differences between solar/wind electricity production and demand. John Randolph of Virginia Tech has provided the following data about the economic favorability of renewable energy: Nuclear: $148/MWh; Coal: $102/MWh; Natural-gas-combined cycle: $60/MWh; Utility solar: <$50/MWh; Wind: <$45/MWH; Efficiency: <$25/MWh; Lithium-ion batteries: $209/kWh in 2017 and expected to be $100/kWh by 2025. Virginia has moderate experience with solar farms and no experience with wind farms compared to its neighboring states. Virginia would do well to study and emulate renewable energy development in North Carolina, which has similar topology to Virginia. Virginia's coal counties could lead in this. The major fossil-fuels state of Texas is way ahead of Virginia in solar energy and wind energy. It is not wise to depend on natural gas for electricity production over the long-term. Methane leaks from drilling sites and pipelines, over a 100-year period, is 34 times more potent that CO_2 at trapping heat. Extracting and burning methane may be as potent for global warming as mining and burning coal to produce electricity depending on the amount of fugitive methane. Increase the percent of electricity generation that AEP and Dominion allow for rooftop net metering. Do not charge for transmission for net metering because local solar generation greatly reduces the need for transmission lines. In fact, the price paid for rooftop solar should be greater than the cost of grid electricity. Allow communities to create solar farms or purchase from commercial solar farms that produce a given fraction of electricity for the community. Require power companies to build or buy more solar/wind energy, build community microgrids for grid resiliency, build battery backup in microgrids for renewable-energy smoothing and grid	The commenter's remarks on renewable energy are appreciated. The specific suggestions for developing renewable technologies is not directly within the purview of the board or this regulatory action, although DEQ agrees that they are important tools for carbon control. The commenter's concerns about methane are acknowledged; however, as the specific purpose of this regulation is to enable linking to RGGI, methane is not addressed in this regulation.

	resiliency. Virginia needs to develop offshore wind farms.	
14. Rees Shearer, Energizing Renewable Growth in Holston Valley and Emory Climate Collaborative; Hannah Ingram	I am pleased and proud that Virginia is preparing an initiative to reduce carbon and other toxic pollutants from utility power plants over time. How Virginia implements this program is critical to its success. Success means improving public health, expanding clean energy employment, saving electric customers money, improving competitiveness, protecting the creatures which share this land with us, and beginning to reduce climate burdens that we have been placing on the backs of future generations. In order to achieve success, DEQ must ensure that Virginia's carbon reduction regulation is trading ready by adopting a market-based approach. Joining RGGI is the best way to make this happen. DEQ will also need to prepare to auction carbon credits, if the General Assembly refuses to join RGGI. The baseline must not be inflated, and must include large industrial boilers. The 2020 base year emissions cap should be no more than 32 million tons and initiate meaningful and deliberate carbon pollution reductions of 3% per year. To protect our forests, the program should include biomass burning facilities. Virginia is ripe for improvements in energy efficiency and solar energy. A 2015 study determined that if Virginia reduced carbon pollution by embracing energy efficiency and clean energy, households could save a yearly average of $415. Adoption of strong customer energy efficiency improvement standards benefits all customers, but especially those with low or moderate incomes. According to the Solar Foundation's 2017 Solar Job Census, Virginia could create over 50,000 new solar energy jobs. But that's if we adopt solar-friendly policies, sufficient to meet just 10% of residential electric load over the next five years. In 2017, Virginia already boasted 3565 jobs in the solar industry - already triple that of coal mining. In southwest Virginia we desperately need clean energy jobs to replace lost coal employment. But Virginia's utilities quietly thwart pro-clean energy policies and job growth. A current example is legislation that would allow power purchase agreements to finance and install solar facilities, but the bill excludes all residential, commercial and industrial customers. Only non-profit organizations would benefit. We have the resources to make clean energy bloom in southwest Virginia--a ready workforce of trained solar technicians graduating from our community colleges and a healthy number of experienced building contractors; developable unreclaimed mine lands and rural electric infrastructure orphaned by the coal industry; and communities accustomed to living alongside the energy industry. These resources offer prime opportunity for both dispersed and utility-scale solar development and employment right here.	Support for the proposal is appreciated. DEQ agrees that energy efficiency and renewable energy are important tools for controlling carbon pollution, and the 5% set-aside is intended for this purpose. Specific issues identified by the commenter are discussed in further detail below.

	Systematically cutting carbon pollution cuts toxic pollutants from electric generating stations as well, offering a dividend in public health improvements. Enhanced public health makes the case for a program of utility carbon reductions by itself. A healthy carbon-cutting program also keeps physically vulnerable Virginians healthy. A strong carbon reduction program for Virginia, shows that we are doing our part to slow the ravages of sea level rise, storm volume and intensity, drought, heat wave, habitat loss, and disease spread, all of which are the marks of a changing climate.	
15. Pam Clough, Environment Virginia	I am concerned about climate change because it threatens our environment and health. My family and friends have experienced extreme weather events that were likely made worse by climate change. Though this is a national and global problem, change starts at home. I support setting the strongest possible standard to cut Virginia emissions from power plants and join RGGI, the most successful regional climate and clean energy program in the country. We can work across party lines to cut pollution and protect our climate while the federal government stalls on climate action. RGGI states have seen pollution decrease by half since 2005 and consumers have saved over $773 million on their energy bills. I request that DEQ adopt and implement a final standard that cuts carbon pollution as quickly and as soon as possible. The 2020 base year cap should be 30-32 million tons with a baseline at the lower end of that range. The cap trajectory should parallel the model that other states in RGGI have implemented to reduce emissions 30% by 2030. The cap should incorporate all planned renewable energy developments in Virginia. The program should set the expectation of continued annual carbon pollution reductions after 2030. Virginia's baseline should also account for the state's untapped energy efficiency potential and incorporate savings that can reasonably be achieved between now and 2020. The American Council for an Energy Efficient Economy ranked Virginia 29th in its most recent State Energy Efficiency Scorecard, placing Virginia well behind all of the RGGI states. Global warming is exacerbating pollution and harming our health. In 2015 Roanoke residents breathed elevated levels of smog pollution 31 days out the year. Residents in the RGGI states are living longer and healthier lives thanks to cleaner air. The program is estimated to have saved 600 lives and prevented 9,000 asthma attacks in 6 years. An Abt Associates report shows that Virginia has already secured $380 million worth of health benefits because pollution across the region has gone down. Virginia's participation would significantly reduce	Support for the proposal is appreciated. The commenter's concerns about climate change and discussion of the health benefits of RGGI are well taken. Specific issues identified by the commenter are discussed in further detail below.

	pollution even further, accelerating the health benefits we have already seen.	
16. Drema Khraibani, Hannah Funk, Lindsey Mendelson; Environment Virginia	Climate change poses increasing threats to Virginians' environment and health. In 2015 residents of northern Virginia breathed elevated levels of smog pollution 99 days out the year. Smoggy skies are expected to grow worse as temperatures rise. This means that we can anticipate more code red days and asthma attacks. The blacklegged tick that can transmit Lyme disease is expanding its presence in Virginia and reported cases of Lyme disease are on the rise. As noted in the Executive Directive, rising storm surges and flooding could impact as many as 420,000 properties along Virginia's coast that would require $92 billion of reconstruction costs. These health concerns can be prevented if we join RGGI. Residents in the 9 member states are living longer and healthier lives thanks to less pollution and cleaner air. The program has been estimated to have saved 600 lives and prevented 9,000 asthma attacks in just 6 years. Because of the health benefits and the many climate impacts this program can provide our state, the strongest possible standard should be set to cut Virginia emissions from power plants and join the region's market of capping and reducing emissions. I implore you to set the 2020 base year emissions cap to be 30-32 million tons with a baseline at the lower end of that range. This cap should mirror the cap that states in RGGI are taking to reduce emissions 30% by 2030. The rule should set the expectation that carbon pollution will continue to be reduced after 2030, and take into account Virginia's untapped energy efficiency potential and all planned renewable energy developments in Virginia. If Virginia links with RGGI, it would be tied to the most successful regional climate and clean energy program in the country. As we have seen across northeast and mid-Atlantic states, we can work together across party lines to cut pollution, clean our air, and protect our climate while the federal government stalls on climate action. RGGI states have seen their pollution decrease in half since 2005, generated $2.7 billion in revenue, and saved consumers $773 million on the energy bills by directly auctioning their emissions. If Virginia follows a similar model it would generate $2 billion that it could use for clean energy, energy efficiency, and coastal resilience programs.	Support for the proposal is appreciated. The commenter's concerns about health issues are well taken. Specific issues identified by the commenter are discussed in further detail below.
17. Dr. Kathleen Price and Dr. Samantha Ahdoot, Virginia Clinicians for	Patients with Lyme disease suffer from pain and inflammation in their joints, facial nerve palsies, heart arrhythmias, and chronic fatigue. Sometimes even with antibiotics, they do not recover completely. Warmer winters and earlier springs create favorable environments for tick and mosquito survival, reproduction and disease transmission. As a result, tick-borne	Support for the proposal is appreciated. The commenter's observations about health issues are well taken. Specific issues identified by the commenter are discussed in further

Climate Action	infections across the country are soaring, including in Virginia. Between 2006-16, cases of Lyme disease increased in Virginia over 3 fold. Other tick-borne illnesses have increased, including Rocky Mountain Spotted Fever. Mosquito-borne illnesses such as West Nile Virus, and possibly Zika in the future are a threat as well. February 2017 was the warmest February on record for our state. In 2018 we had dramatic temperature anomalies, with numerous days reaching 60-80 degrees. Early onset of spring warmth causes many trees and flowers to start blooming earlier and brings earlier onset to the allergy and asthma season. According to pollen count data, the tree pollen season in Richmond is now peaking one week earlier than it did in the 1980s and the peak tree pollen count is now over 50% higher. CO_2 acts as a fertilizer that makes many plants produce more pollen. Higher tree pollen increases ER and urgent care visits for allergies. As a result of decreasing air pollution, RGGI states have prevented up to 800 premature deaths and 390 non-fatal heart attacks. Policy that protects our air protects our health, and saves the public and the government money that otherwise goes to healthcare. RGGI states have avoided between $3-8 Billion in health effects costs. By participating in RGGI, Virginia can reduce the carbon pollution that is causing these changes in our climate, natural world and health. RGGI would also enable Virginia to reduce other air pollutants that threaten public health. As a result of decreased particulate matter, RGGI states have prevented 8000-9000 asthma attacks, over 200 asthma ER visits and 400-500 cases of acute bronchitis. I support the strongest possible standard to cut carbon emissions through participation in a carbon market. I ask DEQ to use its authority to adopt and implement a standard that caps and reduces carbon pollution as fast as possible. The 2020 cap should be between 30-32 million tons. The cap should include carbon pollution from biomass facilities which can be more climate-polluting than fossil fuel power. DEQ should monitor implementation so that it can rectify instances of communities being disproportionally affected by pollution.	detail below.
18. Dr. Douglas Hendren, Physicians for Social Responsibility	RGGI makes good medical sense as well as business sense for Virginians. Sourcing our energy from dirty sources carries very high costs. Abt Associates has analyzed the public health impacts of RGGI over a 5-year period, finding hundreds of avoided premature adult deaths, hundreds of avoided heart attacks, thousands of avoided asthmatic episodes, hundreds of emergency room visits and hospital admissions, tens of thousands of	Support for the proposal is appreciated. The commenter's observations about health issues are well taken. The commenter's concerns about methane are acknowledged; however,

	lost work days, and savings of $3-8.3 billion. Fossil-fuel energy imposes many hidden costs on Virginians. It shortens our lives and sickens our children. It fouls our air, congests our emergency rooms and raises our medical bills. Changes in the atmosphere have brought higher oceans and violent storms threatening coastal cities. The cost to the U.S. of extreme weather events in 2017 came to $306 billion. Virginians cannot afford to be held hostage by the fossil-fuel sector and their political operatives. It is time to make policy decisions based on scientific assessment and common sense. I support setting the strongest possible standards for cutting Virginia emissions, including an initial cap of 30 million tons, with periodic downward adjustment; continuation of the program after 2030, unless superseded by a carbon tax; no exclusion for biomass plants; and no exclusion for methane. Natural gas is worse for our health and for global warming than burning coal. Nearly all of our natural gas is obtained by fracking, which virtually all independent studies have found is associated with a greater than 5% rate of fugitive methane emissions. This makes gas worse than coal with regard to GHG emissions.	as the specific purpose of this regulation is to enable linking to RGGI, methane is not addressed in this regulation. Specific issues identified by the commenter are discussed in further detail below.
19. Roy Hoagland	Referencing Virginia Clinicians for Climate Action information: Clinicians across the state support linking with RGGI. ED 11 will help protect the health of Virginias while also saving money for the state and taxpayers. Summary of cumulative RGGI health benefits, 2009-2014, avoided health effects: 300-830 premature adult deaths, 35-390 non-fatal heart attacks, 420-510 cases of acute bronchitis, 8200-9900 asthma exacerbations, 13,000-16,000 respiratory symptoms, 180-220 hospital admissions, 200-230 asthma ER visits, 39,000-47,000 lost work days, 240,000-280,000 days of minor restricted activity. Value of avoided health effects between $3-$8.3 billion.	The information provided by the commenter is acknowledged.
20. Deborah Kushner	I'm proud to celebrate Virginia's position as the first southern state to consider joining the RGGI. Not only would overall pollution levels decline, but new clean energy jobs would help the labor sector and we would have a new funding source for energy improvements and assistance for low-income customers. Joining RGGI means the road map for Virginia is already in place. RGGI has proven successful in cutting emissions without costing too much. Emissions from power plants in RGGI states fell 5% from 2015 to 2016, and have fallen 40% from 2008, when the initiative began. I urge DEQ to adopt a much lower cap than the 33-34 million that's proposed. We need to clean air quickly, and Virginia's emissions are already very close to the 33-34 figure. All sources of carbon emissions should be included in calculations. Biomass should be included, since 3 coal powered power plants have already been converted to burn wood, and we cannot afford to have others follow suit. Our forests are being harvested at an alarming rate	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.

	to produce wood pellets and shipped overseas. The Partnership for Policy Integrity calls biomass "the new coal." Wood burning power plants are estimated to put 50% more carbon into the atmosphere than coal burning plants, per megawatt hour. Wood is not carbon neutral, since regrowing forests is anything but quick. Additionally, the plan should continue past 2030.	
21. Michael Keegan	The plan should cap and reduce carbon pollution as rapidly as possible, beginning as soon as possible. We are already way behind where we need to be. Based on starting as quickly as possible, the base year should be 2019 and the base year emissions cap should be 20 million tons. The plan should cover carbon pollution from all power plants including from biomass facilities, which can be more climate polluting than fossil fuel power plants. The plan should continue annual carbon pollution reductions in Virginia after 2030. The plan should allow for closely monitoring the implementation in order to respond to instances of disproportionate environmental burdens experienced by any communities, especially low-income and vulnerable communities that have traditionally borne the brunt of pollution.	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.
22. Kiquanda Baker	I ask that the regulations be set at a realistic yet aggressive limit in order for these regulations to have the desired impact on GHG emissions. It is a proven fact that climate change exists and that humans are the main perpetrators. The practices that have led us to this point should be discontinued. Obviously we can't shut every fossil fuel dependent industry down, but we can cut back. The regulation is essential in pioneering the clean energy transition in Virginia. The cap should be set at least between 30-32 million tons. Biomass emissions should be included because it is a fuel source more unclean than fossil fuels. Decreasing our contribution to global warming and thermal expansion would help alleviate sea level rise in Hampton Roads while we continue to create solutions for resiliency. By embracing clean and renewable energy, Virginia can mitigate the negative impacts of burning fossil fuels while boosting the economy. With low income families and communities of color being the most vulnerable to fossil fuel pollutants and the effects of climate change, we need clean energy sources that benefit all people.	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.
23. Garry Harris, Center for Sustainable Communities	We demand healthy communities and a healthy economy, where workers receive the good-paying, family sustaining clean energy jobs, and their livelihoods are protected in the meantime. There is no reason those jobs can't grow right here, and this legislation offers a path to do so. We have worked for years to help lower income communities reduce energy burdens caused by disproportionate impacts of electricity costs and its effects on the quality of life, creating choices between food, energy, and housing adequacy. ED-11 protects the health of families and communities by curbing carbon pollution that has shown to have a direct link with	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.

	enhancing climate change and is exacerbating extreme weather events. On a personal note, I have to take asthma medication on a daily basis. Implementing ED 11 will reduce harmful pollutants that contribute to dangerous smog and soot, causing heart attacks, respiratory illnesses, and even premature deaths. Virginia is the first southern state to take initiative on limiting and capping carbon pollution from fossil fuel power plants. We can take pride pushing to have energy companies take responsibility for toxic emissions that are damaging the health and environment of our communities at a time when the federal government is dismantling regulations that protect us from corporate polluters. Burning coal releases harmful toxins into the air and water, causing respiratory illnesses like asthma. RGGI states, by reducing toxic emissions and switching to cleaner energy, have successfully prevents 8,200 asthma attacks and saved 300 to 830 lives, in a five year period. The starting cap should be between 30 and 32 million tons of emissions by 2020 and continued reduction of the cap beyond 2030. Another significant polluter is biomass; biomass GHG emissions are higher than those from burning fossil fuels. ED 11 contains a woody biomass loophole, which exempts woody biomass plants from the regulation. Such giveaways to industrial polluters render Virginia's program less efficient and give Dominion an unfair economic advantage. Carbon reduction plans have vast potential to reduce climate changing, harmful emissions and expand the economy. Between 2009-14, RGGI states have successfully reduced CO_2 emissions by 35% (compared to 12% in non-RGGI states) by switching from dirty fossil fuels to clean energy. Additionally, the region saw a 21.1% economic growth (compared to 18.2% in non-RGGI states). Virginia's decision to cap carbon emissions through a market-based approach offers a great opportunity to improve the livelihood and health of low-income families and communities of color who are most vulnerable to climate change and dirty fossil fuel pollutants. ED 11 should ensure that there are emission reductions in environmental justice communities and that there is a mechanism that ensures reductions of GHG co-pollutant emissions by facilities located in or near environmental justice neighborhoods.	
24. Kiquanda Baker, Garry Harris	In 2016, the number of solar jobs in Virginia increased by 65%. If the state received 10% of its power from the sun by 2023, Virginia would see over 50,400 more jobs. Virginia's coasts can support offshore wind turbines. Renewable offshore wind energy would produce clean	The commenters' views on renewable energy are appreciated.

	energy and protect the coast from catastrophic oil and gas spills that threaten fish, tourism, and recreation. The wind industry could provide 1.5 times more jobs that offshore oil and gas, creating almost 14,000 offshore wind jobs and 5,000 manufacturing jobs by 2030.	
25. Joy Loving and Anne Nielsen, Climate Action Alliance of the Valley	Overall, this is a good regulation. It will lower Virginia's carbon emissions below what we would emit without this rule, and do it in a way that is efficient and cost effective. Virginia can reduce carbon emissions while also reducing energy costs. Linking Virginia with RGGI allows Virginia to join other RGGI states in a program with a proven track record of success in reducing carbon emissions while allowing our economy to grow. The member states of RGGI are serious about lowering their carbon emissions and would not allow Virginia to link with them if they didn't believe it would be good for them and also lower overall emissions. By linking to these RGGI states, Virginia will need to coordinate with them to not only lower our own carbon emissions, but also to ensure that member RGGI states continue to lower their carbon emissions and maintain funding for their renewable energy and energy efficiency initiatives. Unless prohibited under Virginia law, DEQ should directly auction carbon allowances, in addition to the proposed consignment format. This approach should allow market forces to operate more effectively. Distribute allowances based on energy output, not historic carbon emissions. The initial cap should be 30-32 million tons. Allowing emissions to increase makes no sense. If allowances are given to power plants based on historic carbon emissions, it will still achieve the goal of carbon emission reductions. But it will not provide a new source of income to zero-carbon energy generators. Instead, allowances should be distributed based on updated energy output. This method gives some allowances to zero-carbon energy sources, who can sell the allowances as a new source of revenue. Do not exempt any fossil fuel power generating unit owned by and located at an individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility. Do not exempt power plants that use biofuels. The climate responds to all CO_2 molecules, regardless of their origin. Excluding biofuels would give the power industry an incentive to cut down trees to burn in power plants to avoid buying carbon allowances. Even though RGGI states exempt biofuels, Virginia has many wood-based biofuel generators. DEQ should not read the language of ED 11 too narrowly when it is clear that the impetus behind its issuance is to reduce GHG emissions. Methane, a powerful GHG about 25 times more potent	Support for the proposal is appreciated. Note that it is not possible to conduct both a consignment auction and a direct auction at the same time, and the rule will continue to implement the consignment approach while allowing for future potential participation in a conventional auction. The commenters' concerns about methane are acknowledged; however, as the specific purpose of this regulation is to enable linking to RGGI, methane is not addressed in this regulation. Additional specific issues identified by the commenter are discussed in further detail below.

	than CO_2, accounts for 9% of all U.S. GHG emissions, and almost one-third of that is estimated to come from oil and gas operations. DEQ should interpret ED 11 broadly so as to bring about as much reduction in GHG pollution as possible. The fact that the other RGGI states do not include methane does not prevent Virginia from doing so. Even if exact numbers beyond 2030 are not now known, the regulation needs language that the cap will not increase going forward. Virginia's citizens, agencies and businesses need to know what to expect for their planning purposes. If the regulation leaves open the possibility that the cap will go away or be relaxed, different long-term plans would surely result. The regulation should require close monitoring of implementation to respond to instances of disproportionate environmental burdens experienced by any communities, particularly low-income and vulnerable communities that have traditionally borne the brunt of pollution.	
26. April Moore	The regulations will be extremely important in reining in climate-damaging emissions from fossil fuel-burning power plants. With more than 99% of climate scientists around the world warning that we must get our CO_2 emissions down. Linking Virginia to RGGI is a smart, effective way to significantly reduce GHG emissions. The cap-and-trade approach relies on the free market to do what it does well, with a minimum of government involvement. We know that a cap-and-trade approach works. The RGGI states that are using it have already reduced their power plant carbon emissions by 30% since they adopted cap-and-trade in 2008. And during that time, the economies of these states have increased faster than those of the rest of the country. RGGI states have also lowered their average electricity rates by 3.4%, while the rest of the country's rates have increased by an average of 7.2%. The regulation should include a strong incentive for forest carbon offsets. Because trees take in CO_2 during photosynthesis, they sequester carbon in wood, roots, and soil. Trees are the best technology yet discovered for carbon capture and storage. In fact, scientists rank forests as the single best climate change solution. Some cap and trade programs include forest carbon offsets as a mechanism for transferring money from fossil fuel-burning utilities to forest owners as an incentive to manage their forests for increased carbon sequestration instead of timbering. Given that 62% of Virginia is forested, Virginia should follow the example of cap-and-trade programs that include forest carbon offset credits.	Support for the proposal is appreciated. Although the RGGI model rule does offer states the option to award offset allowances for projects outside of the electric power generation sector, only a single offset project has been implemented in the entire RGGI region since the program's inception. Given the uncertainty of any benefits associated with a complex offset program, DEQ will not, at this time, implement the offset option. However, DEQ does intend to recognize offset allowances generated in other RGGI states in accordance with the RGGI Model Rule, and the proposal has been amended accordingly. The issue of whether or not to implement offsets in Virginia may be addressed in ongoing program reviews.
27. Kim Hafner	We are grateful to DEQ for taking measures to save our lives by enforcing strict regulations on carbon emissions, and by creating a cap and trade initiative which will	The commenter's concerns about methane are acknowledged; however,

	protect the environment and public health. Legislation that will lead us toward 100% renewable, sustainable energy is our best hope. The initial base budget should be 33 million tons or less and decline 3% per year. Methane should be capped. Nothing that is being proposed is actually stringent enough based on the dangers incurred by daily carbon emissions. No fossil fuel power generating unit owned by an individual facility and located at that individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility should be exempt. DEQ should be allowed to directly auction carbon allowances in addition to the proposed consignment auction format. On our small family farm, we are working to sequester carbon by planting trees, and by perennially keeping our pasture in grass. Soil that has higher amounts of carbon as a result of such sequestration holds moisture better and lessens the ground's susceptibility to drought. Soil that has sequestered carbon also has green growth that helps the earth maintain lower temperatures. How might we reward farmers for farming practices which lower carbon emissions by sequestering the carbon in similar ways? It is imperative that you establish an aggressive carbon reduction program. Ideally, this would mean bypassing natural gas and all fracking extraction and transitioning directly to renewable energy. While cap and trade initiatives are positive in that they move us away from coal, they are dangerous compromises. None of us knows if the strictest regulations on carbon will be enough to mitigate the damage that we've done in time to make a significant difference, but we do know that compromises like the RGGI cap and trade, which encourages and rewards fracking, will only guarantee more suffering. In a burning building, there is no time to agree we can try buckets when all that can save us is a fire hose.	as the specific purpose of this regulation is to enable linking to RGGI, methane and natural gas are not addressed in this regulation. As discussed in comment 28, for example, cap-and-trade programs in general, and RGGI in particular, are proven effective emissions reduction programs.
28. Jennie Moody	For 30 years I was engaged in research tracing anthropogenic chemical signatures in the atmosphere, using observations of precipitation, aerosols, and atmospheric gases like ozone to study how pollutants are transported. Working at the University of Virginia, I evaluated the origins of sulfur and nitrogen in Charlottesville precipitation, using meteorological data and atmospheric transport models and was able to establish that higher concentrations of sulfate were associated with atmospheric transport. I am proud to think that this work, along with work I did on my Ph.D. may have contributed in some small but tangible way to the successful cap and trade program instituted by the Clean Air Act that reduced precipitation acidity by reducing atmospheric sulfates. Research published with colleagues at the University of Virginia illustrates that	Support for the proposal is appreciated. DEQ agrees that emissions trading programs are a demonstrated, effective means of controlling air pollution.

	sulfate concentrations dropped substantially, as much as 85% from 1980 to 2009 measuring sulfate concentrations in precipitation and aerosols downwind of North America. This is simply to say, cap and trade works, we can lower emissions and their environmental impact. I support DEQ in the position of being the first southern state to formulate a program to encourage the reduction of CO_2 emissions. Since 1978 we have seen a 70 ppm concentration increase from 335 to 405 ppm. The proposal to cap carbon emissions in Virginia is a positive step toward reducing the atmospheric concentration of CO_2. Because the concentration of atmospheric methane has also been increasing, and methane contributes significantly to the aggregate GHG index, transitioning to energy sources that result in higher fugitive methane emissions are less desirable than transitioning to zero-carbon energy sources. Despite concerns regarding methane, I support a statewide declining cap from 2020-30. Capping CO_2 from Virginia fossil-fuel fired electric generating facilities should allow for the pursuit of multiple pathways to attain lower emissions. A carbon trading market force that creates incentives for energy efficiency and development of zero-emission renewable energy sources would be a positive step forward. However, setting the baseline emission cap below 33 MT should be explored. It is important that models reflect the impact of proposed fossil fuel retirements and account for proposed renewable projects or energy efficiency gains that will be realized on or before 2020. Virginia's participation in RGGI, along with the reentry of New Jersey, means that 20% of the 50 states are creating incentives to lower CO_2 emissions. The implementation of this program should have enhanced benefits, including air quality improvements beyond CO_2 particularly to the extent that present fossil fuel generation is replaced by zero-carbon renewable sources like wind and solar.	
29. Randall Freed, Citizens Climate Lobby (CCL)	Virginia's GHG profile is like most other states, in that by far the biggest source is burning fossil fuels. The best way in the long run to reduce emissions is to introduce a carbon fee-and-dividend approach where we put a fee on carbon in fuels, and refund the money directly to households as a dividend. CCL advocates for this approach. In the short run, the most cost-effective and straightforward way to reduce our emissions is to focus on power plants. The RGGI system works--it reduces millions of tons of emissions per year without harming states' economies. Joining RGGI will provide a clear path for utilities to invest in a way that protects ratepayers and the environment. Most of the RGGI states use these	Support for the proposal is appreciated. Virginia's utilities are regulated by the SCC, which ensures that ratepayers are protected. The primary purpose of the regulation is to address carbon pollution via linking to RGGI in accordance with ED 11; therefore, no fee-and-dividend approach is being considered under this regulatory action.

	revenues for energy efficiency programs or technology upgrades. The Grid Transformation and Security Act will create a structure for Dominion and Appalachian Power to invest $1 billion in efficiency programs over the next decade. It commits those utilities to make 5,000 MW in solar, wind, and grid technology upgrades, and provides a financial mechanism to recoup costs. Instead of plowing allowance money back to the utilities, let's demonstrate how a fee-and-dividend approach works, where environmental fees from sales of allowances get distributed evenly to all households. This approach, which CCL advocates for an economy-wide carbon fee and dividend, offers the best long-term solution.	
30. Ivy Main, Virginia Chapter of the Sierra Club	Putting Virginia on a carbon diet opens up opportunities for the growth of Virginia businesses that develop carbon-free renewable energy or that reduce energy use. The more we displace fossil fuels that emit carbon, like coal and fracked gas, the more room we make for wind and solar, and the more we reward energy efficiency. The timing is ideal. Solar is now the cheapest form of energy in Virginia, and offshore wind is maturing into a powerhouse industry. DEQ proposes to begin our carbon diet in 2020 from a baseline of 33-34 million tons of CO_2. That makes 3% annual reductions less difficult than if we start from a lower baseline. However, modeling suggests a more realistic baseline would be 30-32 million tons. We should use this lower baseline to send the right signal to our market participants. We don't want our utilities to bulk up on carbon between now and 2020, when our carbon diet begins. We want them to start putting healthier practices in place now, so by 2020 they have already begun shedding carbon by employing renewable energy and energy efficiency. Another way to cheat on a diet is to kid yourself about what you're consuming. Burning biomass is the empty calories of the renewable energy sector. Unlike wind and solar, biomass emits carbon pollution, more than coal. Dominion went down a blind alley with biomass, thinking it could meet renewable energy goals while burning stuff. That's bad for Virginia forests, the health of residents, the wind and solar industries and the climate. When you put CO_2 into the atmosphere by burning trees, it doesn't do the planet any good to pretend it's carbon neutral. DEQ also proposes to exclude sources of carbon pollution under 25 MW. That's consistent with RGGI, but the exclusion should minimize the incentive for generators to structure operations in a way that will use this exemption. In conclusion, I commend DEQ for developing this carbon diet, and encourage you to make it rigorous.	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.
31. Earle Mitchell	It is commendable that the board is addressing the problem of burning of dirty fossil fuels to generate electricity. RGGI auctions generate proceeds, which	Support for the proposal and the commenter's discussion of RGGI are

	participating states are able to invest in energy and consumer benefit programs. Programs funded have included energy efficiency, clean and renewable energy, GHG abatement, and direct bill assistance. Virginia could allocate some of these proceeds directly to the southwestern part of our state to provide economic development, education and workforce training to those who have been affected by the decline of coal production. Since RGGI started those participating have realized $ 2.3 Billon in lifetime energy bill savings, 9 million MWh of electricity use avoided and 5.3 million tons of CO_2 emissions avoided. Through 2015, $40.4 million has been returned to consumers through rebates. Rather than suppressing economic growth the participating states have outpaced the remainder of the U.S. during the time that RGGI has been operating. RGGI provides technical and administrative services to all participating states; it is a non-profit organization. There is no glory in re-inventing the wheel when other states have already done much research and have come up with a workable, cost effective system that will clean the air and add good paying jobs at the same time. We in Virginia have already embraced a cooperative structure in that we belong to the PJM system. The function of PJM is to coordinate the movement of wholesale electricity in 13 states. Note the similarity of PJM and RGGI: two organizations working for the common good of the participants. From a humanitarian standpoint we need to confront a truth that has not been adequately addressed. The Journal of the American Medical Association published a report which states that miners working in the Appalachian coal country are now experiencing the highest levels of black lung disease that have ever been reported. We need to phase out coal as soon as possible.	appreciated. Specific disproportionately affected community issues are discussed in the response to comment 55.
32. 301 emails sponsored by the National Wildlife Federation	Thank you for taking steps to create a new carbon market in our state with the potential to link to RGGI and make Virginia a national leader in confronting the threat of a changing climate. Virginia communities and wildlife are already on the frontlines of a changing climate, and impacts like extreme weather and sea level rise are only expected to get worse, unless we act now. Wildlife like the Carolina northern flying squirrel need your help. This endangered species is now living on "sky-islands" on nine isolated mountain peaks in the southern Appalachians. The impacts of a changing climate threaten this special species' last remaining strongholds in the state. CO_2 pollution is the leading cause of climate change, which is already fueling phenomena like massive storms, floods, and megafires. It is critical that we reduce this pollution as quickly as possible. By creating a carbon market and linking to RGGI, we can use a proven, effective market-based solution to reduce	Support for the proposal is appreciated. The commenters' concerns are well taken.

	carbon pollution from the power sector while generating revenue at the same time. This revenue can then be invested in additional climate solutions such as energy efficiency measures and renewable energy. My family, our wildlife, and our environment desperately need effective solutions from the growing threat of climate change. It is your duty to protect us, so please do everything you can to make our state a leader in climate action and carbon markets.	
33. Tyler Privott	I am in favor of passing this regulation. However, I wanted to point out some information that the DEQ failed to utilize in their models when coming up with a cap of 33-34 million tons. This information, if implemented, would further reduce the proposed cap below 33 million tons. To start, the models did not accurately depict the amount of current solar power and amount of future solar power used in Virginia. The state already has more than 360 MW of solar power, even though the model used a current estimate of 274 MW. In addition, the model used to calculate a reasonable cap had an extremely slow growth rate for solar energy in Virginia; however, the amount of solar energy in queue for the next few years will increase the total output by at least 1000 MW, including a 500 MW plant that is being built in Spotsylvania. In addition, DEQ assumes a growth rate in electricity demand of 1.9-3%, but the expected demand growth over the next 15 years is only roughly 1%. Also, DEQ is using information that power plant CO_2 emissions have been overall increasing since 2012. 2012 was an anomaly in terms of weather, with a relatively warm winter and cool summer, which means the overall energy consumption would be low compared to other years; therefore, the total power plant CO_2 emissions would be lower relative to neighboring years. Virginia has also reduced the amount of electricity imports from other states by creating more power plants in the state; because of this, Virginia is now responsible for these emissions since the electricity was made in-state versus out-of-state, which would result in skewed data and growth. Either new models should be created or the regulation should include a lower cap than 33 million tons.	Modeling is a decisionmaking tool that captures a set of information at a certain point in time. Assumptions and inputs that are used to develop a model can vary infinitely; therefore, it is important that every effort be made to make them as reasonable and accurate as possible for the time period under consideration. In order to accomplish this goal, DEQ availed itself of modeling expertise provided by the Georgetown Climate Center. The assumptions provided by DEQ were based on reference cases obtained directly from RGGI, coupled with adjustments made for specific Virginia circumstances. The load growth and renewable energy projections provided were the best available information at the time the models were developed. Since the regulatory action was initiated, other modeling and forecasting exercises have been undertaken by a variety of parties, including DEQ, using updated data. It is important to note that the implementation of the 2018 Grid Transformation and Security Act (see response to comment 51) was one of several factors pointing to the need for additional

		modeling based on new circumstances. 28 million tons has been chosen for the base year cap based on new modeling data performed for DEQ by the Georgetown Climate Center as well as public input; see response to 37 for additional detail. Given the fluid nature of modeling, it is important to note that additional modeling will be performed by RGGI in concert with Virginia as the program progresses in order to assure that the program is operating properly and meeting its goals. Virginia also has the capability to conduct modeling at any time if needed.
34. Mike Sandler, Carbon Share	It is society's responsibility to pass along a livable planet to the next generation. Climate change is a dangerous threat to health, the environment, agriculture, the economy, and national security. Auctioning is important because we have seen in other carbon trading programs the tendency to overallocate permits, leaving the price at the minimum. In RGGI's case, power plants switched from coal to natural gas, leaving the program overallocated and the permit price at $2/ton. In the next 10 years, solar and battery storage will undercut the business as usual case, and make current baselines obsolete. This can be partially remedied with an escalating price floor on the permit price (what California did), but auctioning 100% of permits is better because it lets the market determine the impact of innovation on the permit price. DEQ should study how a "consigned auction" differs from a non-consigned auction. Is the purpose of the consignment to protect the companies from the price signal? A climate dividend is important. Some environmental groups would prefer revenues to be used to invest in solar and wind technologies. But this is the people's money. If companies are going to have to buy permits to pollute, that money belongs to all of us. An equal per capita dividend addresses the regressive impacts of the carbon price on low-income households, and encourages support for the program. In an age of	Support for the proposal is appreciated. The primary purpose of the regulation is to address carbon pollution via linking to RGGI in accordance with ED 11; therefore, no fee-and-dividend approach is being considered under this regulatory action. See the response to comment 65 for a discussion of the industrial exemption. As discussed in the response to comment 26, DEQ will not implement the offset option although offset allowances from other RGGI states will be recognized. See the response to comment 37 for a discussion of the cap.

	economic inequality, a climate dividend could unify the public to fight climate change. A climate dividend could become part of a basic income, addressing unemployment and social justice aspects. In addition to a price floor on permits, DEQ should consider limiting or banning offsets. There should be no exemption for onsite fossil fuel plants. Virginia should adopt its own cap and rules before joining RGGI. Once in RGGI, it may be difficult to change. I have heard that many RGGI states would prefer a tighter cap but are unable to get consensus. Virginia's cap should be less than 33 million tons. Virginia should look at an economy-wide cap, not just on the electricity sector. A good first step would be joining the Transportation and Climate Initiative (TCI). Finally, the Department of Mines, Minerals and Energy should change its name to the Department of Sustainable Energy.	
35. Mark Belleville	I am a professor at the Appalachian School of Law, and I teach energy related courses. I strongly support efforts to create an trading-ready GHG emission reduction program for new and existing power plants, with the goal of joining RGGI. It has been 30 years since James Hansen testified before the Senate on the risks of climate change, 26 years since the UN Framework Convention on Climate Change, 11 years the Supreme Court handed down Massachusetts v. EPA, and 5 years since President Obama's Climate Action Plan and we still have no federal law or rule addressing the emission of GHGs like CO_2 and methane. Into that void, states must step. There are many ways to internalize the externalities associated with emitting GHGs; while the RGGI program may not be my first choice, it has grown to work fairly well. One of the benefits Virginia enjoys in entering RGGI at this stage is that it has some empirical data on which to judge the program's efficacy and its fit with Virginia's goals and policies. I'd like to point out some features of the RGGI program that should help inform Virginia's decision, most of which weigh in favor of joining. The serious design flaw of the RGGI program was an initial overallocation of allowances. The spread between allowances and actual emissions was exacerbated by a decrease in energy consumption caused by the economic downturn, the displacement of coal by newly available cheap natural gas, and increased renewable energy deployments. This overallocation led to floor-level prices for allowances, and the absence of a robust trading program. The allowance auctions operated as a small carbon tax, an expense that utilities and their customers barely noticed. This problem has been addressed. By retiring a number of allowances and setting new reduced cap levels, the program is in a	Support for the proposal is appreciated, as is the commenter's discussion of RGGI and Virginia issues. The commenter's concerns about the SCC's role in managing rates is well taken. SCC proceedings and audits are all public; this vertically integrated system is complemented by the RGGI program's open and transparent processes. All auction information is tracked and publically available. At the end of a compliance period, it will be possible to determine how many allowances were bought and sold, by whom, and at what price; based on this information one could then determine to what degree program costs are recoverable. DEQ is therefore confident that SCC's oversight role as well as the transparency of the complete process will ultimately protect Virginia's consumers.

	position to effectuate behavioral changes to the tune of a 3% reduction from current levels each year going forward. While the price of allowances has risen, as it was designed to do, it is still fairly low compared to other cap-and-trade programs around the globe, and mechanisms exist to prevent it from rising too much. Even as the overallocation caused depressed allowance prices, the program has always been successful at raising revenue for the participating states. More than 90% of the allowances have been auctioned off, raising nearly $3 billion for participating states. While it is for member states to decide on how to allocate allowances and spend proceeds, all states have auctioned the bulk of their allowances and utilize the bulk of the proceeds on energy efficiency, clean and renewable energy, and direct bill assistance. Thus, even if the allowance prices were not enough to change utility behavior, these expenditures have helped contribute to not-insignificant emission reductions in member states. With 39 auctions behind it, the quarterly regional auctions are mature and seem to function today with little difficulty. The RGGI program applies only to fossil-fuel fired power plants >25 MW. While I would prefer to see greater coverage for broader industry, the limited scope should provide some comfort for policy-makers worried about a broadly negative economic impact. It is possible that the cap-and-trade program could be expanded beyond fossil-fuel power plants, as this has occurred in both California and Europe. The RGGI program has built in enough safeguards to avoid the demise of affordable electricity. It allows only a limited use of offsets. But it allows increasing use of offsets if the prices for allowances reach certain levels. The program allows unlimited banking of allowances, and has a 3-year, both of which help utilities accommodate fluctuating annual electricity demands. And it has a reserve price that will now rise 2.5% per year; this helps assure that the allowances are utilities hold continue to have value. One of the most serious challenges Virginia and RGGI will face is that most of the currently participating states have deregulated their electric utilities far more than Virginia has. I would focus my attention on how much the SCC will allow Dominion and APCo to pass on increased costs to its customers in the SCC-approved tariffs. I urge the rulemakers to be transparent with the public on this issue. As a rate payer, I am comfortable with a small rise in my electric rates associated with joining RGGI. But I also am aware that recent tax cuts have benefited the bottom line of both major Virginia electric utilities, and there is likely enough excess profit there to absorb the	

	additional costs. I appreciate the Attorney General's opinion that this program is achievable under existing law. There will be serious and plausible litigation over Virginia's attempt to effectuate this change without the General Assembly's involvement. The General Assembly will need to pass legislation to determine how allowances are allocated and revenue spent. For this reason, I would urge DEQ and other involved agencies, as well as our delegates and senators, to work to provide explicit approval for this proposal. State leaders must be clear-eyed as to the sea-level and storm-surge threats facing Norfolk/Hampton Roads, including the naval base and export facilities. Hurricanes affecting mid-Atlantic states will continue to grow in frequency and intensity. Studies suggest degradation and loss of economic value to the Chesapeake Bay, and loss of fish stock and forest productivity. While climate change is a global problem, self-interest and self-preservation should also motivate the state to reduce its emissions. This is a very good proposal, and I strongly support it.	
36. Coleman Dickerson	This regulation needs to be put in place, but not without some changes to the modeling process and general process of assumptions. The proposal grossly overestimates the projected growth in Virginia's future electricity consumption. This overestimation results from neglecting the strides the state has been making in increasing solar power, and neglecting the reduction of increasing electricity demand given a weakening stream of electricity imports. I insist that the projections for Virginia's future electricity demand be re-modeled and realistic expectations for this growth replace the 1.5% - 3% estimation given in the current report. Updating the models with more relevant and accurate information would support the 33 million ton cap versus the 34 million ton cap. Setting the cap at 33 million tons would provide a more accurate goal for the front end of this regulation's time allotment. Reaching the estimations for our 2030 cap is more feasible when the range between starting goal and ending goal is decreased.	See the response to comment 33 for a discussion of DEQ's modeling efforts and the response to comment 37 for further discussion of how the final cap was established.
37. Victoria Glasgow	While it is a step toward responsible GHG management, the proposed cap is higher than what we can meet under current projections. I urge DEQ to update its baseline scenario to reflect more realistic estimates. The current cap of 33 or 34 million tons CO_2 is based on the assumption that energy demand is going to increase at a rate of 1.9% and 3% for residential/industrial and commercial development. When including solar capacity, residential/industrial demand growth is under 1% for the next 15 years. Moreover, commercial demand is growing only because of the prevalence of server farms. The energy demand of these solar farms is covered by	As can be seen from this and many other comments, a wide range of caps has been advocated. Recommendations ranged from a low of 20 million tons per year to a high of 37.5 million. Many recommendations fell within a range of 30-32 or 33-34. It has been determined that 28 million

	newly-installed solar. For example, a 500 MW plant has been proposed in Spotsylvania, and Microsoft has purchased more than half of the energy it will produce. Spotsylvania's 500 MW solar farm is projected to cut 1 million tons of CO_2 per year, so why is this already-planned projection not accounted for in the cap? Additionally, Dominion has 3 new natural gas plants that will displace coal plants and result in reduced emissions: another reason to lower the cap, since the plants will be able to provide the same amount of energy with lower emissions compared to coal. If DEQ keeps its baseline emissions too high, it inflates the cost of reaching the cap. DEQ should consider including ECR as part of the cap (9VAC5-140-6210) plus output-based allocation (9VAC5-140-6215). The cap should also start in 2019 to effectuate the Executive Order as soon as possible.	tons is the appropriate level for a starting base budget. This initial budget will enable the reduction of CO_2 while enabling Virginia's participation in RGGI to operate smoothly and effectively. Since the regulatory action was initiated, modeling and forecasting exercises beyond the department's original modeling have been undertaken by a variety of parties using updated data. Notably, modeling by NRDC using updated assumptions projects business-as-usual emissions of 28 million tons in 2020 (see comment 121), and NRDC recommended that the cap be set accordingly. As discussed elsewhere, implementation of the 2018 Grid Transformation and Security Act, which calls for significant utility energy efficiency and renewable energy initiatives from Virginia investment owned utilities, will further lower emissions beyond what was originally proposed. Additionally, new modeling was conducted with updated information on a business-as-usual basis for Virginia and the 9 RGGI states that indicated a cap of 28 million tons was achievable and reasonable; see the response to comment 33. Ultimately, the program needs a starting point, and, having reviewed the new information and considerable public input, DEQ believes that 28 million tons is a reasonable

		program starting point. More detail on how DEQ's modeling was performed is discussed in the response to comment 33. While DEQ expects to achieve steady emission reductions whatever the starting cap, the state also needs to balance that goal with the reality that there will always be a degree of uncertainty as to the composition and amount of emissions in the future that no model can accurately predict with certainty. Imposing a cap that is too stringent or too lenient will not help Virginia reach its goals, and DEQ believes the final cap strikes the proper balance. As discussed in greater detail elsewhere, RGGI routinely undergoes comprehensive, periodic reviews to consider program successes, impacts, and design elements. Caps can be modified as needed to ensure long-term program success, not only for RGGI but in the specific interests of the Commonwealth.
38. Chris Bolgiano	I support DEQ's cap and trade proposal as at least a first step to addressing climate change. However, it is so limited in scope that Governor Northam should issue a new Executive Order and expand state authority to address certain shortcomings. The irony of facilitating gas pipelines while promoting a cap and trade program for CO_2 is not lost on us. To avoid subverting addressing climate change, CO_2 equivalents should be calculated for net emissions impact of methane by fracked gas production and transport. These methane-CO_2 equivalents must be included in the CO_2 budgets and allowances, because utilities burning coal or oil will move to gas to claim lower CO_2 emissions. A program based only on CO_2 will stimulate fracking, gas transport, and pipelines. Methane is a greater climate danger than CO_2. The Attorney General has ruled that "The Board has the authority to establish a statewide cap on GHG emissions." GHGs include methane. As Bill	The commenter's concerns about methane are acknowledged; however, as the specific purpose of this regulation is to enable linking to RGGI, methane and natural gas are not addressed in this regulation. As discussed in the response to comment 26, offsets will not be implemented at this time. Biomass is further discussed in the response to comment 67. For a detailed explanation of how the consignment auction will operate, see comment 136.

	McKibben says, moving from coal and oil to gas is like kicking OxyContin by taking up heroin. Fossil fuel utilities should pay for the privilege of damaging our environment and Virginia should apply those revenues toward climate solutions, as RGGI does. According to DEQ staff, "Unlike a conventional auction, such as the one RGGI manages, a consignment auction is revenue neutral, and will enable Virginia to link to RGGI while staying within the bounds of Virginia law." In addition, if Virginia law prohibits the return of auction revenues to the state, or if the General Assembly must approve revenue-positive auctions, then DEQ should outline the appropriate steps to overcome these obstacles, because RGGI states gain billions of dollars from auctions which are then used for climate solutions. The single most powerful natural climate solution is forest conservation. Because trees take in CO_2 for as long as they live, which for most of the hardwoods that constitute the majority of Virginia's forests is at least four centuries, trees are the best technology for carbon capture and storage. Yet the proposal does not include forest carbon offset credits, which RGGI allows up to 3% of CO_2 emissions, and the California market allows up to 6%. Given that 62% of Virginia's land base is in forest, and most of that acreage is owned by more than 400,000 private individuals and families, this incentive would benefit all Virginians not only with climate change mitigation but also by long-term protection of water and air quality. To omit forest carbon offsets, and miss the opportunity to encourage retaining forests for the carbon they have already locked up and the amounts they would continue to sequester, would be a strategic mistake. Counting biomass as carbon neutral is another mistake. In a letter to Governor Cooper of North Carolina concerning the increase of biomass burning, more than 100 scientists stated: "Biomass plants emit more CO_2 emissions per unit of electricity than coal or gas plants. In addition, it releases harmful particulate matter and smog precursors.… Removing the CO_2 emitted from burning trees for electricity requires waiting decades to a century for trees to regrow. Forests in the U.S. South are logged at a rate four times that of South American rainforests. A 2016 study showed that logging reduced the potential of the U.S. forest carbon sink by approximately 35%. Increasing carbon sinks by way of forest conservation and restoration plays a significant role in emissions reduction." While logging residues give off CO_2 during decay, removing them for burning depletes soil by removing nutrients, degrading forest productivity including the regrowth of the trees supposed to balance emissions from burning. Whole trees are being harvested for pellets, an industry that has	

	degraded forests in the southeast and is moving into Virginia. There is no mechanism to verify that trees regrow on site, and cutover forests are ripe for development. Even if trees do regrow on site, decades are required for such forests to capture and store as much CO_2 as was emitted by burning, and during that time CO_2 emissions will increase because trees can't grow fast enough to offset them. This proposal covers only one facility that co-fires coal and biomass but should also include the others that burn only biomass, and ideally not allow burning biomass at all.	
39. John Reeves	DEQ and the board deserve wide support for this key initiative. The evidence and science is overwhelming that anthropogenic climate change is very real. Threats to our health, economy, infrastructure, coastline and national security plus carbon pollution from burning fossil fuel is significantly contributing to ramping-up climate change and sea-level rise. Practical, market-based strategies should be optimized to improve Virginia's poor rankings on energy efficiency plus on renewable energy, especially on solar energy capacity and initiatives. Virginia should expedite steps to partner with RGGI. The legislature may also need to concur, so preparations and good findings must be available to ensure this concurrence. Many benefits await good measurement, especially lowering of wasted energy, swinging demands on power grids and peaking facilities, and cost of power bills. The regulation should include practical, market-based ways to continue CO_2 reductions after 2030. There are few justified exemptions for fossil-fueled heat and electricity generators at a factory. There may be a reasonable compromise on some exemption of blended in biomass/forestry byproducts. It seems that Virginia forestry and pulp and paper facilities can justify levels above 10% blend with fossil fuels--maybe up to 30 or 50%?	Support for the proposal is appreciated. See the response to comment 65 for additional discussion about the industrial exemption, and response to comment 67 for further discussion of treatment of biomass.
40. Adam Brookman	We have been given a tremendous opportunity to protect our future with this carbon emissions cap. While this program is best we can hope for right now, the choice we have been presented for how many annual millions of tons of CO_2 to be released is simply appalling. I understand that in any negotiation there is a give and take for all parties involved, but why must we give away what has been taken from us for so long. To choose between 33 and 34 million tons of CO_2 is insulting and reeks of nothing but greed. The reason we have these two choices is obviously the representatives from the major power companies of Virginia. Thank you for giving your customers options. I propose a different amount. I propose that there be an annual allotment of no more than 25 million tons of CO_2 with the amount reducing by 8% each year. This goal may be aggressive but easy goals is something we do not have time for. The text of the proposal consistently refers to "fossil fuels" when discussing CO_2 reduction. While fossil fuels are one of	See comment 37 for further discussion of the cap and comment 67 for further discussion of the treatment of biomass.

	the worst contributors of CO_2, they are not exclusive. The burning of wood or biomass produces equal if not more CO_2, so why should it be treated any different? There should be no exemption for any power producing facility on any of their units that produce CO_2 in any way shape or form. Biomass burning power generation must be held accountable for their CO_2 emissions.	
41. Maria Papadakis	I am writing to indicate my strong support for a cap-and-trade allowance system and participation in RGGI. The regulation should include opportunities for CO_2 emission offset allowances in agriculture (forest offsets and avoided methane from agricultural manure management operations). This would enable the farm sector to benefit financially from efforts to protect forests and to afforest, and from efforts to mitigate methane, a highly potent GHG. The regulation must make a provision for the voluntary renewable energy market set-aside allocation mechanism, as allowed for by RGGI. The set aside enables the voluntary renewable energy market to contribute to the state's overall CO_2 mitigation goals and compliance opportunities, and are critical for the process of reducing emissions. It is also needed to avoid weakening the in-state economy for renewables. The absence of a set aside could cause Green-E to quit certifying in state green power. The Center for Resource Solutions explains that "If a cap-and-trade program is adopted and implemented without a voluntary renewable energy set-aside mechanism, Green-e may be unable to continue to certify voluntary sales of renewable energy from the state, or the additional cost of allowance retirement to the voluntary purchaser may preclude certified sales from generation in the state. This would mean that voluntary buyers in these states will get their certified renewable energy from outside of the state in the future. A voluntary renewable energy set-aside will allow for this demand to be met by resources in the state--allowing your state the opportunity to maintain the private investment dollars that may otherwise go elsewhere."	Support for the proposal is appreciated. DEQ recognizes the value of voluntary renewable energy market; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME. Given the uncertainty of any benefits associated with a complex offset program, DEQ is not, at this time, proposing to implement offsets; see the response to comment 26. See comment 51 for further discussion of the set-aside.
42. William M. Shobe, University of Virginia	Output-based updating of allocations is appropriate and prevents emission leakage. Model runs show that output-based updating of allowance allocations helps reduce leakage while retaining incentives to shift generation away from high-emitting sources. Free allocation of allowances acts as an implicit subsidy for the generation of electricity by granting to ratepayers the market value of the stream of allowances. Generators take this grant into account when calculating their marginal cost of generation and so can maintain relative competitiveness with the generators in the rest of the PJM region. This prevents generation from migrating out of Virginia and into the uncapped portions of PJM. Output-based allocation seems the appropriate choice given the potential for leakage of emissions into the rest of PJM.	See the response to comment 33 for a discussion of modeling, and the response to comment 37 for discussion of the cap. The commenter correctly notes that carbon intensity is decreasing.

	The consignment auction improves efficiency and fairness. By enhancing liquidity in the auction, requiring consignment probably improves price discovery in the RGGI market. The act of consignment and the resulting requirement that Virginia utilities purchase back what they need may make allowance prices more salient to market players and the generators. Consignment auctions monetize the value of the grant of allowances to the generators--they establish a clear market value of the grant. This allows the SCC to establish whether allowance value is being transferred to ratepayers rather than being retained by generators. Given the value of the free grant of allowances, it is critical that ratepayers be protected from generators pocketing the value of allowances. The consignment auction helps make this possible. The ECR helps correct over-allocation. In every emission market established to date, allowances have been over-allocated at first. In the case of RGGI, the cap has been reduced dramatically due to the initial over-allocation. Even after the initial allocation, costs often fall faster than the cap leading to lower than expected allowance prices. The proposed rule continues this pattern of over-allocation, since DEQ has set the initial cap too high. This makes the ECR an important backup mechanism for ensuring that emission reductions will be greater, if the costs of achieving those reductions fall below expectations. The initial cap should be 30 to 31 million tons. DEQ has overestimated business-as-usual emissions over the next 15 years. This makes achieving the reductions for a given cap level appear more expensive than they really are. DEQ's analysis is not off by just a little, it is grossly in error. The agency has provided an analysis that is inconsistent with facts that were readily available to the agency at the time it did its analysis. What is more, the bias is clearly in one direction, overstating the emissions that would occur in the absence of this rule. This, in turn, overstates the cost of achieving a given reduction. "Reference Case 1" (RC1) assumes that Virginia will generate zero electricity with solar PV for the entire forecast horizon. This assumption is false. At the time DEQ did its analysis, Virginia had more than 100 MW of solar PV in operation with more than 250 MW under construction. By the end of 2017, Virginia had just more than 360 MW of solar PV capacity in operation. This capacity can be expected to generate approximately 720 GWh of electricity per year. In addition to the solar already in operation, the PJM interconnect queue has several gigawatts of solar PV slated for Virginia. Two years ago, Dominion had agreed to have 400 MW in place by 2020, but in April 2017 the company announced	

	in its IRP its intention to build around 240 MW per year for the next 15 years. This estimated solar build was for Dominion's "no carbon regulation" case. APCO and ODEC had both announced that they were adding solar capacity as well. There are currently over 700 MW of Virginia solar PV capacity in the engineering and procurement stage. The PJM interconnection queue has close to 6 GW of capacity planned for Virginia in the next few years. Much of this was already on the queue when DEQ assumed zero solar build for Virginia over the next 15 years. At the time of its analysis, DEQ had reason to know that Virginia would probably have at least one GW of solar PV capacity by 2020. Yet the agency assumed in RC1 that there would be zero solar PV built in Virginia before 2031. This inflates the appropriate level of the cap. Reference Case 2 (RC2) is only marginally better; again, understating likely solar PV capacity and generation that would occur in the absence of the rule. The agency assumed that, by 2020, Virginia will have a capacity of 344 MW and will generate only 819 GWh of solar PV electricity. This is less than half of what would reasonably have been expected even before ED11 was announced. Taking the current 360 MW and adding 240 MW per year, this implies solar PV generation of about 1300-1500 GWh more per year than estimated in RC2. If the solar PV displaces half coal and half natural gas, then DEQ has overestimated CO_2 emissions by nearly 1.5 million tons per year due to underestimating solar capacity. The mistake is much greater for RC1, where solar PV is incorrectly assumed to be zero. By underestimating the amount of solar PV generation that would have occurred without the rule, DEQ has overestimated business-as-usual emissions by around 1.5 million tons/year. Both scenarios ignore already contracted capacity increases in the short run. Both of DEQ's Reference Case scenarios err by assuming unrealistic rates of growth in electricity generation. This, in turn, results in unrealistically high capacity factors for coal plants in Virginia and unrealistic growth in fossil fuel generation capacity, mostly natural gas. This further inflates expected business-as-usual emissions and is used to justify a higher cap than is necessary. In its April 2017 IRP, Dominion estimates future generation growth to be 1.3% per year. Accepting Dominion's estimate for demand growth, DEQ made a serious error in its modeling of reference case emissions by assuming unrealistically high growth rates in generation. DEQ's generation scenario for RC 1 has generation growing at an average rate of 1.9% per year and RC2 has it growing at 3.4% per year. Dominion represents 70% of generation in Virginia. The	

	APCO region, which is the second largest in Virginia, has flat or declining demand. The remainder of the state is too small to make up the difference, but does not have growth rates higher than Dominion's. DEQ assumed a higher growth rate for generation than the electric utilities are using in their own capacity planning. This inflates the estimated need for fossil fuel combustion in future years. Dominion has over-forecast demand every year since at least 2012. Its forecasts of future generation have fallen dramatically over this same period but are still too high and will continue to fall in the next few years because of a flaw in its forecasting methodology. Generation has grown faster than demand since 2015 because of a Virginia state policy to repatriate generation and reduce imports of electricity. The process of repatriating imports is now essentially complete. Dominion is anticipating small amounts of exports over the next few years, given that it is nearing completion of 3 new natural gas generators. Now that the process of repatriating generation is complete, generation and demand will tend to grow at the same rate. Recent growth in electricity demand in Virginia has been less than 1% per year even as the state economy has grown following the last recession. Recent trends in both residential and industrial demand have been negative, that is negative growth in demand. In the industrial sector, this is due to a shift to less energy intensive industries. In the residential sector, this is due to the penetration of energy efficient technologies and improvements in the energy performance of the building shell. The one source of increase in electricity demand in Virginia in recent years has been server farms. This is a small fraction of overall electricity demand in Virginia and is already accounted for in Dominion's forecast. DEQ has no basis for its grossly overstated estimates of future demand growth in Virginia. Many firms building server farms want to cover their energy demand with renewable generation and the firms are increasingly insisting that the generation be local. Server farm demand cannot account for the growth in fossil fuel emissions assumed in DEQ's faulty analysis. DEQ’s two reference cases make different assumptions about 2017 total generation: 96,786 for RC1 and 93,305 for RC2. At the time DEQ did this analysis, there was zero chance that demand would be as high as assumed in RC1, but this is consistent with the general pattern of unsupported and erroneous assumptions in its analysis. Actual generation for 2017 was 93,500 GWh. To be conservative, take the higher of the two 2017 generation estimates from DEQ’s reference cases, 96,786 GWh	

	(even though it didn't actually happen) and increase it at 1% per year. The resulting generation profile shows that DEQ's assumed generation is in excess of any reasonable expectation by 3,600 GWh per year by 2020 and 10,500 GWh by 2031. If you assume that each GWh displaces half coal and half natural gas, then each 1,000 GWh is associated with on the order of 1 million short tons of CO_2. In light of this, it is clear that DEQ's analysis has grossly overestimated BAU emissions. Combined with the solar PV analysis, the 2020 emission overestimate is on the order of 4 million tons of CO_2 per year. The assumption of half displacement of gas and half coal is somewhat conservative. Chances are that more coal dispatch will be displaced. Dominion's IRP had a BAU scenario and a scenario for operating under a cap under the Clean Power Plan. One of the major differences between these two scenarios is the retirement of significant coal capacity in 2020, when the CPP was to come into force. These coal plants were not retired under the BAU scenario. This implies that substantial reductions in coal dispatch can be anticipated under this cap, which will ultimately be tighter than what would have been true under the CPP. And coal dispatch is already falling sharply due to the addition of the new natural gas capacity. Net electricity generation from coal in Virginia fell from 15,600 GWh in 2016 to 10,110 GWh in 2017. This downward trend will continue as Dominion brings its Greensville natural gas power plant online in 2019. DEQ has failed to make a case for a cap greater than 30 million tons per year. In recent years, any increases in generation due to load growth (including repatriating imports) has been offset by reduced emission intensity of generation. Since nearly all increments to generation in Dominion's IRP are solar PV, through to the end of the 15-year planning horizon, emission intensity is bound to fall further. In its reference cases, DEQ assumes a natural gas price of $2.83 in 2017 rising to $3.95 in 2020. In April 2018, the spot price of natural gas hovered around $2.75/MMBtu. To match DEQ's assumption, natural gas prices must rise more than 30% in the next two years. And yet, the futures price for natural gas, as of April 3, 2018, is $2.70. DEQ assumed a high rate of growth in natural gas prices and plugged that assumption into its model even though it was known at the time that there was a substantial probability that the price would be lower. This adds more upward bias in the estimated business-as-usual emissions.	
43. Jonathan Miles, James Madison	The proposal will not provide any avenues for voluntary market customers to ensure that their renewable energy purchase contributes to emissions reductions beyond the	DEQ recognizes the value of voluntary renewable energy market; however,

University	cap set by the program. All RGGI states with the exception of Delaware and California have implemented voluntary renewable energy set-aside mechanisms. Without the set-aside, Virginia generation would be ineligible for participation in the Green-e Energy market, meaning that regional voluntary market customers would have to invest in renewable energy in nearby states in order to have the renewable energy certified. This would benefit neighboring states and discourage increased investment in renewable energy in Virginia. The set-aside mechanism is important to continue to stimulate private investment in renewable energy in Virginia, which in turn will promote local jobs and businesses, and further reduce GHG emissions generated in the state. I strongly encourage the inclusion of the voluntary renewable energy market set-aside allocation mechanism from Section XX-5.3(l) of the RGGI Model Rule.	the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME. See comment 51 for further discussion.
44. Christina Luman-Bailey, City Council of Hopewell, Virginia and Chair, GoGreen Virginia	I am concerned that the industry exemption barely passed; although I agree that all major carbon emitters should be held accountable, it is typically the coal-burning utilities sector which is the biggest offender and has a monopoly on the customer market, whereas industry must face more competition and may need more flexibility re cost of production in order to compete in the private sector. The threshold of 90% biomass in order to claim carbon-neutral seems unreasonable. Basing the credit for carbon neutral on the percentage of biomass makes for a more reasonable, scientifically-based formula and is fair. I am glad to see the DEQ moving forward with air pollution controls, but I think that a more reasonable, scientifically-based proposal will be more accepted by all and therefore more successful.	See comment 67 for further discussion of how biomass will be addressed.
45. Mayor Tom Sibold, City of Covington; James H. Hudson, III, Mayor, Town of West Point; William Hodges, Chairman, King William County Board of Supervisors	The WestRock Paper mill in Covington is a significant economic driver for our community providing over 1000 jobs and supporting over $200,000,000 in local investment through supplier purchases, payroll, and taxes every year. If care is not taken, the proposed regulation could have a serious and negative impact on the mill. The West Point Paper Mill has been an important economic driver for the Town of West Point and the broader region for over 100 years. Today, the Mill employs roughly 500 people in good paying jobs. The Mill is the largest taxpayer in the Town of West Point (and one of the largest in King William County), and contributes over $100,000,000 to the regional economy every year. Papermaking is an energy intensive and trade exposed industry, and the mill operates in an intensely competitive business environment. The West Point Paper Mill is of critical importance to King William County. The mill is one of the largest employers, one of the largest taxpayers, and one of the	The commenters' concerns are well taken. The cap-and-trade program has been designed to meet the goal of reducing carbon pollution--which will be beneficial to the manufacturing sector--while protecting the economy. Industrial generation and biomass are discussed in greater detail in responses to comments 65 and 67. DEQ agrees that free allocation of allowances is integral in ensuring the smooth function of the consignment auction.

	most significant corporate members of the community. The hundreds of jobs that the mill provides, the hundreds more that it supports, and the millions of dollars that it injects into the local economy are irreplaceable. Simply put, the mill is the lifeblood of King William County. DEQ should take great care in crafting the final regulation to ensure the mills are not placed at a competitive disadvantage. Specifically, the regulation should: 1) Maintain the existing exemption for industrial generation. 2) Fully recognize the carbon neutrality of biomass by amending the regulation to allow for the subtraction of biogenic emissions from any covered source. This is an approach that is consistent with established science and the existing RGGI program. 3) Preserve the free allocation of carbon allowances currently in the regulation, as a full auction of allowances could significantly increase the financial impact to energy-intensive industries.	
46. Virginia Solar Energy Development and Energy Storage Authority	The Authority was established to 1) facilitate, coordinate, and support the development of the solar energy and energy storage industries and storage projects through programs that increase the availability of financing for solar energy and energy storage projects; 2) facilitate the increase of solar energy generation systems and energy storage projects on public and private sector facilities; 3) promote the growth of the Virginia solar and energy storage industries; 4) provide a hub for collaboration between entities, public and private, to partner on solar energy and energy storage projects; and 5) position the state as a leader in research, development, commercialization, manufacture, and deployment of energy storage technology. If carbon emitting generation is reduced, cleaner forms of power generation will become more widespread. The addition of energy storage will allow intermittent renewables to continue providing power at times when conventional generation would typically be required, leading to further carbon reductions. The Authority recommends that a portion of any proceeds resulting from the auctioning of the 5% of allowances set aside for DMME be used to advance renewable energy coupled with energy storage technologies. Legislators and the Governor, through their creation of this Authority, recognized that accelerated deployment of renewable energy and energy storage technologies will support a more robust and secure electric power grid. It will also lead to decreased carbon emissions, help grow the energy storage industry and create economic benefits for Virginia and its citizens.	DEQ recognizes the value of renewable energy coupled with energy storage technologies; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME. See comment 51 for further discussion of the set-aside.
47. About 25 individual commenters.	General opposition to the proposal was expressed.	The commenters' concerns are recognized.
48. 272 emails sponsored by	I urge you to drop plans to join RGGI, a short-sighted cap and trade program. It seeks to limit CO_2 emissions, but it incentivizes switching from coal to fracked gas,	Executive Directive 11 directs DEQ to "1. Develop a proposed regulation for

Food and Water Watch	exchanging methane for CO_2. That's not progress. Implementing RGGI would ultimately mean more fracked gas and pipelines in Virginia. We don't need schemes like RGGI. For over 40 years, the Clean Air Act has succeeded by requiring each source of pollution to meet individual, technology-based emissions controls that minimize emissions without the lack of accountability that purchasing credits and offsets brings. Effectively, cap and trade programs like RGGI just set up a pay-to-pollute scheme that big polluters can take advantage of year after year.	the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that: a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits." (Emphasis added.) In other words, the proposed regulation is designed to meet the Governor's mandate to control CO_2 via participation in an emissions trading program. In the absence of federal action to address climate change, Virginia is therefore taking active steps to address this pollutant--but not starting from scratch. The effectiveness of Virginia's carbon control program will be maximized by linking with the only realistically available program for controlling carbon. The control of methane emissions is indeed important; however, this specific regulatory action is not the means by which that can be accomplished. Methane is controlled elsewhere in the Regulations for the Control and Abatement of Air Pollution as appropriate, and other measures

		addressing methane may be addressed at a different time in accordance with the federal Clean Air Act and state law. Because the primary purpose of this regulatory action is to enable Virginia to link to the RGGI program, the regulation was drafted to adhere to the RGGI Model Rule as closely as possible within the framework of Virginia-specific administrative requirements. The commenters are correct that the federal Clean Air Act has been extremely effective in reducing air pollution. Emissions trading programs, which are authorized under §§ 108, 109, 110, and 302 of the Act and implemented under 40 CFR Part 51, are part of the Clean Air Act success story. Emissions trading is a proven means of reducing air pollution; see, for example, comments 28, 113, and 136. Cap-and-trade sets a specific goal and a schedule on which the goal must be met. Clearly, linking to RGGI will ensure additional reductions in carbon pollution not only in Virginia but in the region. Joining RGGI will impose additional controls on each source of pollution beyond other individual, technology-based emissions controls. Note that RGGI specifically addresses CO_2, not methane. RGGI issued the "CO_2 Emissions from Electric Generation and Imports in the Regional Greenhouse Gas Initiative:

		2015 Monitoring Report" on April 27, 2018. This market analysis summarizes data from 2005-15 for electricity generation, net electricity imports, and related CO_2 emissions for the participating states. It demonstrates that carbon emissions in the RGGI are decreasing in intensity; essentially, carbon intensity is being decoupled from electricity generation.
49. Elizabeth Struthers Malbon	It appears that the decision to participate in a CO_2 cap and trade program has already been made by the board, the so-called DEQ, Governor Northam, former Governor McAuliffe, or Dominion. The sad thing is that distinctions between these individuals and agencies may be distinctions without a difference. No one can expect the citizens of Virginia to trust these individuals and agencies given their support for pipelines. The evidence for the decision having been made is in the public notice: "In addition to any other comments, the board seeks comment on whether the initial Virginia CO_2 Budget Trading Program base budget for 2020 should be 33 million tons or 34 million tons, and declining accordingly by 3% per year. After considering public comment, the board will make a final selection of either 33 million tons or 34 million tons." So, the public is being asked to comment on whether we want our air polluted by a huge amount or by somewhat more than a huge amount. I would like the board to think about who is pushing for this program in the first place and who will benefit from it. It is disingenuous of McAuliffe and Northam to act as if they are being responsible in thinking about the dangers of the CO_2 that Virginia's power plants are pumping into the atmosphere, hastening global warming with its sea-level rise and extreme weather events. Participating in such a systematic and continued polluting of the atmosphere might give the impression that something is being done to clean up the air or slow down global warming, but this is not the case. What is needed is regulation that would require energy companies to take real steps toward cleaner air and mitigating global warming by moving away from fossil fuels altogether and utilizing the fast-growing and less expensive technologies for solar and wind power. Such a short-sighted cap and trade program has not worked elsewhere. This program creates incentives for switching from coal to fracked gas. Methane from fracked gas is a more powerful driver of global warming than coal. Fracked gas benefits the companies that extract, transport and sell it, and a cap and trade	See response to comment 48. As discussed in comments 28, 113, 136 and elsewhere, cap and trade programs are proven, effective means of controlling pollution.

	program would pass that advantage along to power companies that burn it--and to any politicians they support. The cap is excessively high, and the price of permits is too low, allowing energy companies to buy or trade their way out of reducing emissions. Such a company could also hold their cheaply-bought allowances to offset future failures to reduce emissions. This program only addresses CO_2 emissions and ignores the impact of methane on climate change and air quality. It would allow switching from coal to fracked gas, effectively worsening climate impact while still complying with the cap and trade agreement. It hardly seems coincidental that two Virginia Governors who were supportive of or tolerant of the building of two interstate pipelines for fracked gas and one state-wide energy monopoly that supported them would now be encouraging a cap and trade program that lets burning this other fossil fuel instead of coal count as environmentally responsible. Money to encourage favorable legislation and regulation has never been a problem for Dominion Energy, and clean air has never been a priority for them. However, the law requires clean air to be the board's priority. You are hardly in a position to pat yourself on the back if you allow only 33 tons of CO_2 pollution instead of 34 tons while turning a blind eye to methane pollution. For over 40 years the Clean Air Act has succeeded by requiring each source of pollution to meet individual, technology-based emissions controls. The citizens of Virginia need and want bold climate solutions that continue to do that and do not compromise the wellbeing of our communities--in terms of air quality, water quality, and overall quality of life in a world feeling the effects of global warming hastened by the use of all fossil fuels. We are not fooled by this pay-to-pollute scheme, and neither should you be.	
50. David Kuebrich	The cap-and-trade polices of RGGI, the E.U., and California have done little to reduce carbon emissions. It's important Virginia learn from the errors of these plans and do better. For example, it would likely be better to impose a flat fee on the use of fossil fuels. This approach would not be nullified by external factors such as an economic decline that kept emissions under a cap. In addition, an imposed fee provides both fossil-fuel users and consumers with predictable price increases. A cap and trade policy can easily lead to disputes, and well-lawyered and politically muscular companies such as Dominion are very savvy at winning disputes. In the past, the benefits of cap and trade have been hyped. Years later, supporters learn the promised reductions in emissions didn't pan out. But for the years between the initial glowing headlines and the later realization of meager results, many citizens and public officials feel a	See response to comment 48. As discussed in comments 28, 113, 136 and elsewhere, cap and trade programs are proven, effective means of controlling pollution. In addition, RGGI has a proven track record in reducing carbon pollution. We recognize the commenter's concern about methane from pipelines; however, that is not the subject of this regulatory action.

	reduced sense of urgency to develop other policies for limiting emissions. Governor Northam may feel if he proves his green creds by creating a cap and trade program, it will then be politically feasible to approve the Atlantic Coast and Mountain Valley pipelines. If so, he's wrong. I ask that DEQ convince our Governor to create a smart plan for reducing carbon emissions and to cancel the pipelines.	
51. 3Degrees Inc.	3Degrees applauds Virginia's decision to implement a CO_2 Budget Trading Program and join RGGI. This will secure the state as a national climate leader, and greatly expand the scope of the regional carbon market, improving market efficiency and lowering costs of compliance across the region. The proposal does not provide an avenue for voluntary market customers to ensure that their renewable energy purchase contributes to emissions reductions beyond regulation. The Voluntary Renewable Energy Market Set-aside allows allowances to be paired with renewable energy at no added cost to the voluntary market. In order to support private investments in renewable energy, 7 RGGI states and California have implemented a renewable energy set-aside. This mechanism sets aside about 2% of the allowances and makes them available for free to be paired with voluntary renewable energy purchases. The renewable energy set-aside will lead to continued demand for Virginia generation in the voluntary market and allow the generation to be eligible for Green-e Energy certification. In addition to the avoided emissions benefit being important in private investment decisions, it is also a requirement of Green-e certification. Green-e certifies tens of millions of megawatt hours of renewable energy every year, including renewable energy generated in Virginia, and, as the only certification for the voluntary renewable energy market in the U.S., is the standard for private purchasing of renewable energy. Where states have introduced cap-and-trade regulation without a renewable energy set-aside, Green-e has required that Green-e certified renewable energy from these states be matched with purchased allowances equal to the generation's emissions reduction benefit on the grid. This adds a significant cost to renewable energy from these states, such that they generally exit the voluntary market. Where private purchase of allowances is not possible, generation from that state is ineligible for Green-e certification. Without Green-e certification, Virginia generation will be less desirable for voluntary purchasing and will lose financial support from the voluntary market. Since Virginia currently only has a RPS goal, the primary markets for Virginia renewable energy generation are	DEQ recognizes the value of the voluntary renewable energy market as an important tool in reducing carbon pollution but has decided not to implement a separate voluntary renewable energy set-aside. The structure of the general 5% set-aside will be under the purview of DMME, which is the appropriate state agency to implement renewable energy and energy efficiency programs. DMME may, at the appropriate time and in accordance with its regulations and policies, seek to implement a voluntary renewable energy market set-aside or its equivalent. However DMME structures the set-aside, it is important to bear in mind that energy efficiency will be an important tool in the control of carbon pollution. Energy efficiency programs reduce in-state demand, which results in the reduction of carbon pollution and the control of potential leakage. Note that renewable energy projects in Virginia should be considered in the context of the Grid Transformation and Security Act of 2018 (SB966), that: - Requires utilities to make $1.145 billion in investments in energy efficiency projects and low-income energy assistance

	adjacent state RPS or the voluntary market. The voluntary market is currently the primary way that high quality renewable energy remains in the state. Local projects risk losing voluntary market support if the renewable energy set-aside is not included. 3Degrees has worked with small-scale and residential solar and wind projects in Virginia, supporting the projects by facilitating the sale of the premium RECs for use by voluntary customers. The voluntary market is generally providing funding for projects that would not receive funding from compliance REC markets, and often providing more funding per MWh. In some cases, the projects would be not financially viable without this revenue stream. If the voluntary renewable energy set-aside is not included, there would no longer be an opportunity for 3Degrees to support projects of this kind in Virginia. We urge DEQ to encourage private capital investing in renewable energy by including the renewable energy set-aside.	over the next 10 years. - Authorizes the SCC to deem 5,000 MW of solar and wind energy projects to be in the public interest, paving the way for approval of new clean energy projects. - Commits Appalachian Power to make a separate investment in 200 MW of new solar capacity. - Promotes energy technology including battery storage and pumped storage in southwest Virginia. - Requires review of state regulations that hinder clean energy development. - Creates a transparent stakeholder process to expand energy efficiency program offerings. - Creates a transparent stakeholder process to make recommendations for solar program expansion, including net metering, community solar, and siting. DEQ expects that opportunities for voluntary renewable energy projects will be encouraged as a result of this initiative.
52. 3Degrees Inc.	3Degrees encourages DEQ to allow the issuance of CO_2 emissions offsets. High-quality carbon offsets can be an important tool for a successful and economic cap-and-trade program. While offsets have not been used to date for compliance in RGGI, as the cap lowers we believe offsets will be an important tool for achieving emissions reductions cost while encouraging innovative climate solutions. Offset projects can address emissions reductions in uncapped sectors and provide other co-benefits.	Although the RGGI model rule does offer offsets, only a single offset project has been implemented in the RGGI region thus far. Given the uncertainty of any benefits associated with a complex offset program, DEQ is not, at this time, proposing to implement offsets; see response to comment 26.
53. American Council for an Energy-Efficient Economy (ACEEE)	Energy efficiency reduces emissions quickly and at a lower cost than any other CO_2 compliance option by reducing the need for power generation. State energy efficiency policies and projects can be the quickest and cheapest means to reduce generation from fossil fuel-fired power plants. Energy efficiency improves air quality	DEQ recognizes the value of energy efficiency as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what

	and saves consumers money. It boosts local economies by creating diverse, high-quality jobs across the construction, engineering, financial, environmental, manufacturing, and industrial supply chains. In 2015, RGGI states invested 64% of allowance revenues on energy efficiency, amounting to 60% of cumulative investments. Programs funded by these investments are expected to return more than $1.3 billion in lifetime energy bill savings. Energy efficiency investments through RGGI contributed to reducing the number of premature deaths and illness in the northeast since 2009. DEQ proposes a set-aside of 5% for the control of CO_2. Given the benefits and low-cost CO_2 reductions energy efficiency provides, we recommend that all set-aside revenues be allocated to energy efficiency projects. However, current market and regulatory barriers to investment in energy efficiency can hinder its use as a compliance strategy. DEQ should consider methods for allowance distribution to address these barriers. Typically, a set-aside is a small portion of a total cap of allowances, which means that energy efficiency is treated as a resource on the margin. This is not consistent with Virginia's energy efficiency potential, nor does it make economic sense. The incentive in a market-based regulation should drive emission reductions by the lowest cost means, which in this case is energy efficiency. Instead of a set-aside, an allowance approach could preferentially award allowances to energy efficiency programs. Allowances could be allocated on an updating output basis according to kWh generated or saved. Ideally, such an approach would award allowances to zero-emission savings and generation first. The remaining allowances could go to fossil-fueled electric generators. An updating output-based allocation provides a transparent and predictable price signal, and rewards measures that deliver lasting CO_2 reductions. There is untapped potential for non-utility energy efficiency programs in Virginia over the next 10 years. The 5% set-aside does not reflect the level of potential investment in energy efficiency that the state could achieve. We recommend a set-aside of 10% in order to provide a more robust financing stream for energy efficiency projects. Increasing the set-aside would lead more cost-effective emissions reductions. Modeling indicates that increasing the set-aside would not impact rates. Energy efficiency measures also reduce overall customer bills, helping to alleviate any potential rate increases. DMME should use the set-aside to invest in energy efficiency projects that save energy and reduce utility costs for public and private sectors. While ratepayer-	programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement the set-aside. DMME may, at the appropriate time and in accordance with its regulations and policies, implement an energy efficiency set-aside as described by the commenter. The set-aside will be 5% in the early stages of the program; the set-aside may be revised at a later date as the state gains experience with the program and with the program DMME develops.

	funded programs for residential and commercial customers in Virginia will ramp up over the next 10 years, large industrial customers will not be served by these programs. DMME can fill this gap. Technical assistance programs targeted at industrial customers can identify potential projects and guide the implementation process. We encourage DEQ to clarify that combined heat and power (CHP) and waste heat-to-power (WHP) projects are eligible for set-aside funds. Other RGGI states have used their auction revenue to support CHP deployment. DMME can leverage its experience operating the Commonwealth Energy Fund, using revenues to make loans to high growth potential early stage Virginia companies focused on energy efficiency and pollution prevention or establishing a revolving loan fund to finance energy efficiency investments at low interest rates for other markets, including public entities, residents or businesses. Financing products could be paired with utility rebates in order to further spur investment. Revolving loan funds have several benefits. These programs are sustainable and can have considerable market impact. Virginia currently has a goal to reduce energy consumption in public buildings 15% by 2017. Through the Virginia Energy Management Program (VEMP), DMME helps state agencies, institutions of higher education, and public bodies reduce utility consumption by working with energy savings performance contractors. In parallel with VEMP, Virginia recently launched the Clean Energy Development and Services (CEDS) program to provide grants and loans for energy efficiency, renewable energy, and alternative fuel projects in state and local agencies. In spite of these efforts, the state has only met about one-third of this energy savings target. We recommend that DMME use the set-aside to expand energy efficiency offerings for public buildings, through VEMP or deeper incentives as part of CEDS.	
54. Virginia Advisory Council on Environmental Justice (ACEJ)	Many members of the environmental justice (EJ) community have been skeptical or opposed to market-based solutions to carbon reduction. Many community members believe their voices have not been heard during program implementation in other states. Concerns with carbon trading include the lack of regulation of co-pollutants, hotspots, equity of allowance allocation, and lack of public engagement. Perhaps the most central concern from an EJ perspective is that many EJ organizations prefer guaranteed emissions reductions at the source of polluting facilities in EJ communities, an outcome that market-based solutions can't guarantee directly. DEQ can structure a program with complementary policies that produce outcomes that EJ	The commenter's concerns are acknowledged. In addition to controlling carbon pollution via this regulatory action, DEQ implements a robust permitting and compliance program to ensure that federal and state standards for controlling air pollution are met.

	groups prefer. We urge DEQ to keep this concern at the forefront, and explore ways to carbon reduction that would achieve guaranteed emissions reductions at the source.	
55. Virginia Advisory Council on Environmental Justice (ACEJ)	DEQ should formalize rules for meaningful engagement of EJ communities. The Clean Power Plan required states to demonstrate how they were meaningfully engaging low-income communities, tribal communities, and communities of color. DEQ should likewise set concrete criteria on how the state plans to engage EJ communities throughout the design and implementation of the regulation. DEQ should participate in a dialogue on allowance allocation and the identification of potential hotspots. DEQ should create a plan for sharing the results of the proximity and cumulative impact analysis to the public, including an education and outreach plan to communities that are convenient and understandable. These methods should be targeted to "meet people where they are" in order to maximize community involvement for specific communities. A toolkit was created by community advocates in coordination with Green for All to ensure meaningful community engagement to comply with the Clean Power Plan. DEQ should use this toolkit as a guide to design its own plan for community engagement during this process. ACEJ recommends the creation of a long-term plan designed to increase participation of EJ communities. DEQ should formalize a process to gather feedback from community members affected by climate change, including creating a sustained dialogue to discuss complementary policies that may be adopted to maximize emission reductions in EJ communities. ACEJ recommends that DEQ host community forums in locations that are experiencing threats from climate change, and explain how this rule is designed to strengthen the state's commitment to fighting climate change.	Community involvement is important to all DEQ programs, and DEQ has a robust community involvement program. Effective community involvement strengthens public confidence in DEQ, and encourages those who are most concerned with agency decisions to inform and help implement them. In addition to a formal Community Development Policy, DEQ is also taking the following steps as part of its strategic plan and commitment to build community involvement: - Provide opportunities for meaningful community involvement in all agency programs, and consistently look for new ways to enhance public input, and include development of education materials and training opportunities for the public. - Identify and implement steps that enable early public involvement and collaboration in significant environmental decisions. - Seek input reflecting different points of view and carefully consider this input when making decisions. - Work to ensure that decisionmaking activities are open and accessible to all interested individuals and organizations, including those with limited experience participating in environmental decision making. - Develop innovative ways to present information on the agency web site and

		elsewhere, and ensure that information is useful, understandable and easy to find. DEQ's EJ Coordinator has also been consulted for advice on communicating and working with vulnerable communities. The EJ Coordinator will provide this assistance on an ongoing basis as the rule is implemented. Routine RGGI program reviews will also provide the opportunity for any affected community to bring attention to any issues that may arise. Linking to RGGI will make Virginia a participant in RGGI's regularly scheduled program reviews. These comprehensive, periodic reviews consider program successes, impacts, and design elements. Stakeholder meetings are held throughout the program review process in order to encourage stakeholder engagement and the submission of comments from interested parties. As part of this process, the department will evaluate how the program is working from a Virginia standpoint as well as in the context of the other RGGI states. Any issues identified with respect to affected communities may be identified and resolved as part of this exercise. In order to clarify that this review process will take place, the proposal has been modified to add a new Article 10, Program Monitoring and Review.

		This provision specifies that in conjunction with the CO_2 Budget Trading Program program monitoring and review process, the department will evaluate impacts of the program specific to Virginia, including economic, energy and environmental impacts, and impacts on vulnerable and environmental justice and underserved communities. The department will also develop a plan to encourage increased participation by affected communities.
56. Virginia Advisory Council on Environmental Justice (ACEJ)	DEQ should complete a robust proximity and cumulative impact analysis to determine the environment and health impacts of co-pollutant emissions and pollution from sectors not subject to the carbon cap for EJ communities. Although capping carbon emissions from power facilities is the scope of the rule, we must study all major sources of carbon and other forms of pollution in Virginia when determining the full scope of environmental health effects in EJ communities. For instance, while reducing carbon from the electric sector has been a major focus of numerous advocates, the largest source of carbon pollution in Virginia is from the transportation sector. Other states in the region are launching a series of listening sessions to explore how to cut carbon from transportation while improving the equity and quality of service. Indeed, EPA has identified proximity to vehicle traffic as associated with increased exposure to toxic gases and particulate matter, which is hazardous to human health. A cumulative impact analysis from Kentucky revealed that "strong relationships between exposure related health problems and vulnerable demographics, such as poverty, educational level, and certain age groups." Similar analysis, in coordination with other state agencies and conducted with input of EJ stakeholders would help the state identify existing pollution hotspots and environmentally stressed communities so that the state can design a carbon reduction program to alleviate harms to those communities. DEQ should prioritize the perspectives and feedback of community members over industry. If hotspots are found, DEQ should create a remediation plan to reduce environmental hazards and lower pollution in environmentally stressed communities. DEQ should solicit the input of community members and other interested stakeholders for corrective remediation	Fossil fuel-fired units are subject to a host of regulatory and permitting requirements that specifically target and control emissions of criteria pollutants and toxics. Ultimately, the control of CO_2 will reduce global warming impacts and concomitant welfare impacts on disadvantaged communities. As discussed in the response to comment 55, the opportunity to elevate specific concerns about potential problem areas will be available during routine program reviews. Note that the board's ability to address transportation sector emissions is limited by statute. DEQ believes that the monitoring and review components of the RGGI program will enable any leakage of emissions to be identified and corrected. As demonstrated in RGGI's April 2018 market analysis, carbon intensity in RGGI states is decreasing.

	of past practices.	
57. Virginia Advisory Council on Environmental Justice (ACEJ)	DEQ proposes to allocate 5% of the allowances to DMME to assist the department in abatement and control of air pollution, presumably through investments in energy efficiency and solar. Ninety-five percent of the allowances are proposed to be allocated to the polluters, which is unacceptably high. If only 5% of the allowances are directed to DMME, it must maximize opportunities to assist families and communities who've been disproportionately harmed by existing energy policy. DEQ should specify that the DMME allocation is directed toward low-income communities. In the alternative, conduct an open decisionmaking process where communities have a say in how allowances are allocated. Energy efficiency and solar energy will advance Virginia's goal to combat climate change and reduce carbon pollution. However, the state would benefit by advancing clean energy in communities who need it most. Low-income and families of all races and ethnicities pay more for utilities, which means there may be cost savings to disadvantaged communities while reducing air pollution.	DEQ recognizes value of directing pollution control efforts toward low-income communities; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement the set-aside. DMME may, at the appropriate time and in accordance with its regulations and policies, implement an energy efficiency set-aside for low income communities as described by the commenter.
58. Virginia Advisory Council on Environmental Justice (ACEJ)	Wood and other types of biomass plants release more carbon per unit of energy than coal plants, in addition to localized criteria pollutants. These plants should be fully accountable to the carbon cap and should be included in the proximity and cumulative impact pollution analysis. RGGI caps carbon on power facilities 25 MW or greater, allowing power facilities with multiple combustion turbines that individually fall below the threshold but are collectively greater than 25 MW go unchecked. DEQ should regulate these types of units holistically, and consider ways to place limits on facilities below the 25 MW threshold. New York will begin covering sub-25 MW peaker plants, a step other RGGI states can voluntarily take. EJ groups have long opposed carbon offsets on principle to not allow facilities to continue or increase pollution by avoiding localized pollution reduction. Localized pollution reduction in EJ communities is the central concern of EJ advocates with cap-and-trade programs. ACEJ supports the recommendation of several EJ organizations in the RGGI region to eliminate the use of offsets as a compliance option.	See the response to comment 67 for a discussion of biomass. To our knowledge there are no sub-25 MW peaker plants, existing or planned, in Virginia. Regardless, current state regulation (9VAC5-20-70) prohibits circumvention of air quality requirements by constructing multiple facilities in a piecemeal fashion in order to avoid regulation. As discussed in the response to comment 26, DEQ is not, at this time, proposing to implement offsets.
59. Virginia Advisory Council on Environmental Justice (ACEJ)	DEQ should coordinate with other state agencies, localities, and community organizations to study the effects of the regulation in coal-dependent communities to ensure a fair and just transition from fossil fuels to clean energy. The coalfield counties in southwest Virginia have borne disproportionate economic and environmental burdens as coal has been extracted. Virginia coalfields are now left with pollution from mining and an economy struggling to recover. Relevant state agencies should conduct an economic analysis to identify sustainable investment and other job creation opportunities for coal communities.	The commenter's concerns about coal-dependent communities in southwest Virginia are well taken; see the response to comment 55 for further discussion of how communities will be addressed.

60. AdvanSix, Greif, ODEC, Virginia Manufacturers Association (VMA)	It has been the policy of the state to avoid the imposition of regulatory requirements "which are more restrictive than applicable federal requirements" unless a showing of necessity supports a more stringent Virginia rule (VA Code 10.1-1308 A). The Administrative Process Act establishes a procedure whereby the General Assembly reviews regulations that are more restrictive than applicable federal requirements (VA Code 2.2-4014) and has the opportunity to judge whether such regulations are necessary. The board should adhere to this long-standing approach and leave any such regulation to the appropriate time and approach determined for the nation by Congress and EPA.	The board may indeed promulgate regulations in the absence of a specific federal requirement to address a state-specific need. DEQ notified the appropriate legislative committees of this regulatory action in accordance with § 10.1-1308 in November 2017.
61. AdvanSix, Greif, ODEC, Virginia Manufacturers Association (VMA)	Cost-effectiveness is a fundamental premise for good regulation. When government burdens its citizens by regulation, the benefits should outweigh the burdens. The proposal fails this basic premise. The proposed regulation is not cost-effective and the cost burden far exceeds any purported benefits. In EO-57 and ED-11, then-Governor McAuliffe revealed the non-environmental motive for mandating a CO_2 cap-and-trade program in Virginia: to "grow the clean energy economy" and "make clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio." ED-11 notes an increase in "the number of solar jobs in Virginia" and the increase in "revenue for energy efficiency businesses in Virginia." While these are laudable goals, it is a misuse of governmental authority to use environmental regulation for non-environmental purposes. There are other, more appropriate authorities and programs to accomplish these economic goals. It appears that the environmental benefit envisioned from the regulation of CO_2 emissions is the mitigation of the risks to Virginians from climate change. The administrative record is devoid of scientific data or other information to support the conclusion that the proposal would have any perceptible effect on the severity of storms or flooding in Virginia. The preamble to the proposed regulation contains a chart of "Health Benefits of Incidental Reductions in SO_2 and NO_X." The rationale is that regulating emissions of CO_2 would have the "incidental" benefit of reducing emissions of SO_2 and NO_X. However, there are numerous other air regulatory authorities and programs addressing emissions of SO_2 and NO_X, including their own cap-and-trade programs. Thus, if additional regulation of SO_2 or NO_X is deemed necessary, there are other, more appropriate regulatory programs to directly address this necessity. Virginia does not have to resort to CO_2 regulation to indirectly address concerns with SO_2 or NO_X emissions. More specifically, the board cannot say the proposed regulation is needed to address emissions of SO_2 or NO_X . Incidental reductions in SO_2	Flexible, market-based emissions trading programs provide the most cost-effective means of reducing air pollution. The program sets an overall cap but otherwise does not dictate which sources must make reductions. Through emissions trading, the program delivers the lowest cost reductions possible. Virginia has years of experience and considerable success with this kind of program. In addition to the inherent flexibility provided by emissions trading, the program also provides for the allocation of allowances to the entities with a compliance obligation. Allowances have value, and that value will be realized in the consignment auction, with revenue returning to compliance entities. The revenue returned to compliance entities from the compliance auction will serve to offset and mitigate the costs of the program for compliance entities and consumers. The analysis in the record is clear on these points. While the program minimizes costs through

	and NO_X provide no rationale for imposing the proposed CO_2 emissions cap-and-trade program in Virginia. DPB's Economic Impact Analysis states: ". . . EPA and other federal agencies use estimates of the social cost of carbon (SC-CO_2) to value the climate impacts of regulatory rulemakings. The SC-CO_2 is a measure, in dollars, of the long-term damage done by a ton of CO_2 emissions in a given year. This dollar figure also represents the value of damages avoided for a reduction of a ton of CO_2 emissions in a given year (i.e. the benefit of a CO_2 reduction). It should be noted that the federal model estimates of the social cost of carbon are for the world overall. Thus it is not possible to quantify the Virginia-specific benefits." There is a reason why the value of damages avoided in Virginia is impossible to quantify. The effect, if any, of reducing CO_2 emissions from Virginia's electric power sector on the severity of storms or flooding in Virginia would be negligible at best. The regulation would provide no measurable environmental benefit to Virginia. Climate change and reduction of GHG emissions are global issues. Climate change is not a local phenomenon and to the extent man can craft a solution to climate change by reducing CO_2 emissions, that solution cannot be accomplished by disjointed state and local approaches. If any regulation of CO_2 in the U.S. is deemed necessary to address climate change, that regulation must be undertaken and applied uniformly throughout the country, not state by state or locality by locality. The costs of the regulation outweigh any purported benefits. In its Economic Impact Analysis, DPB notes that the proposal likely would increase electricity costs for Virginia's citizens and businesses by no more than 1.1% ($2015) by 2031. However, a recent study by the Cato Institute showed that electricity costs in the RGGI states rose by 4.6% between 2007 (pre-RGGI) and 2015. This increase was 64% higher than the increase in electricity costs in a sampling of 5 non-RGGI states. As the data from the RGGI states show, adoption of the proposed CO_2 emissions cap-and-trade program will add millions of dollars per year to the electric bills of the citizens and business of Virginia. Virginia has a robust manufacturing sector and is ranked as the fourth most competitive state in overall manufacturing competitiveness in the nation. Moreover, Virginia is ranked the most competitive southern state for manufacturing. However, this position would be jeopardized by increasing energy costs. The Cato Institute study found that from 2007-14 the economies of the 5 non-RGGI comparison states grew 2.5 times faster than the RGGI states. During the same period the RGGI states lost 35% of energy intensive businesses, whereas	emissions trading and mitigates costs through allowance value, it also produces real benefits for Virginians. The administrative record demonstrating the impacts of climate change and the benefits of encouraging clean energy in Virginia toward the protection and improvement of Virginia's environment is well-documented. The focus of the EO 57 Work Group was to evaluate options under the Governor's existing authority while simultaneously creating more clean energy jobs. (The legal authority to develop this program in the first place is well established; see the response to comment 76 for more detail.) The process consisted of monthly meetings with presentations from the public. Numerous presenters described the impacts of climate change to the Working Group, and presenters included Dominion Energy, the American Petroleum Institute, Covanta, WestRock, and other stakeholders involved in manufacturing and energy generation. The Work Group also received over 8,000 written comments during a 3-month public comment period. The basis for EO 11 and this regulatory development action are, therefore well-established. Note that other commenters describing detailed environmental and fiscal impacts to the state were also submitted during this proposed regulatory development stage; they

	the 5 non-RGGI comparison states only lost 4%. While the non-RGGI comparison states' overall goods production grew by over 15%, the RGGI states lost 13% of overall goods production. This decline is reflected in industrial electricity demand with the RGGI states falling 17% while non-RGGI comparison states only fell 3%. The greater decline in energy demand in the RGGI states cannot be attributed to greater energy efficiency in those states. In fact, the RGGI states improved by 9.6%, while the non-RGGI comparison states improved by 11.5%. Even as the economy was recovering from the 2008 recession, industry was leaving the RGGI states. If the program is enacted in Virginia, electricity costs for manufacturing facilities will undoubtedly increase, by as much as 4-5% by 2031. This increased cost of operation will diminish Virginia's competitive advantage. If Virginia participates in RGGI, we can expect the same fate for our industry that the RGGI states have experienced--industry will go where costs of energy are lower.	are summarized here and the full comments are part of the public record (see, for example, comments 108, 121 and 139). DPB's analysis was based on the best available information, including an analysis of potential changes in residential, commercial, and industrial customer electricity bills prepared for the department by the Analysis Group, an internationally recognized economic consulting firm. In addition, the Virginia Joint Legislative Audit and Review Commission (JLARC) in its Fiscal Impact Review of ED 11 (December 2017) found that the fiscal impact of the proposed regulation on state government should be minimal. The impact is estimated to be negative in 2020 when the regulation takes effect and be approximately $1.9 million (in 2017 dollars) in 2031, the last year for which information is available for developing an estimate. Nearly all of the impact is because of the impact to electricity costs for state agencies and public higher education institutions. Based on the results of these studies as well as various modeling exercises, DEQ maintains that impacts on electricity consumers will be minimal. In fact, the latest analysis of customer bills based on updated modeling shows that average bills will slightly decrease as a result of the rule. Non-carbon benefit

		information provided in the public notice comes from DPB's analysis and quotes EPA COBRA analysis. The latest COBRA analysis again shows significant economic co-benefits resulting from criteria pollutant reductions as a result of this rule. The primary purpose of the regulation is to control CO_2; however, it is accurate to note that there will indeed be other air quality benefits associated with the control of carbon pollution. This discussion is part of the comprehensive economic analysis required by state law that attempts to identify significant impacts--direct and indirect--of the regulation. No analysis of the costs and benefits of the proposal can accurately say that there will be no impacts on other pollutants. DEQ agrees that climate change is a global problem. However, in the absence of a federal program, the Commonwealth is well within its authority to address air pollution within its borders. Linking to RGGI is not a "go it alone" approach; it will enable Virginia to leverage its pollution reduction efforts with a well-established, proven effective interstate program. As discussed in RGGI's most recent market analysis, carbon intensity is decoupling from energy generation in the RGGI region. In addition to its own analyses DEQ has reviewed the results of the RGGI program and finds that costs have been

		contained and benefits have been realized. See, for example, the most recent recent report prepared by the Analysis Group, "The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States: Review of RGGI's Third Three-Year Compliance Period (2015-2017)." This analysis found that RGGI continues to to lower CO_2 emissions while benefiting local and regional economies and employment opportunities. The report estimates that RGGI states will realize $1.4 billion in net economic value from RGGI's implementation during the 2015-2017 period. According to the report, the program also will create more than 14,500 new job-years (the equivalent of one full-time job for the duration of one year) due to the program's implementation during the past three years. In addition, CO_2 emissions from power plants have dropped by more than 50% over the 9 years since RGGI began. DEQ realizes that the electric generation system in RGGI is different, and that Virginia's participation in RGGI will be via consignment rather than direct auction; however, all indications are that linking to RGGI will be beneficial for Virginia. The energy price projections resulting from the updated modeling are lower than the previous modeling exercise in 2017. Thus, the cost of the program will be less for

		consumers and regulated sources than previously estimated. Ignoring the costs of carbon pollution will endanger Virginia's competitive advantage, and linking to RGGI is a step toward addressing that risk. DEQ is well aware of the need to address air pollution in the fairest, most cost-effective means possible, which is why the program is flexible and allows emissions trading to seek out the lowest cost reductions possible. DEQ has also taken measures to ensure that the program goals are realistic and can be reasonably achieved; see, for example, the response to comment 37. In short, the program has been designed to minimize impacts on businesses and consumers while achieving DEQ's air pollution control mission to protect public health and welfare.
62. AdvanSix, Greif, ODEC, Virginia Manufacturers Association (VMA)	The regulation imposes a carbon tax and cedes this tax authority to RGGI. The regulation envisions a process whereby conditional allowances are allocated by DEQ to regulated sources. Those regulated sources are compelled to consign the conditional allowances to RGGI for auction. Regulated sources throughout Virginia and the RGGI states can bid on the allowances. RGGI states have taken the auction revenue and used it for a variety of purposes, one of which is not related at all to the goal of reducing CO_2 emissions: 8% of the revenue was used "for state budget reduction," just like any other tax revenue that goes into the state's coffers. The cap-and-trade program in Virginia is supposed to operate differently. Revenue generated by the auction of conditional allowances consigned by a regulated Virginia source is supposed to be returned to that source owner, less RGGI administrative fees. DEQ has indicated the revenue received by owners of regulated electric utilities will "flow to rate payers pursuant to SCC requirements." However, we have no idea that will actually happen or to what purposes the revenue would be put. The provisions governing the allocation and auction of CO_2 emission allowances, whether conducted by DEQ under the	The definition of "tax" is well established in state and federal law. The purpose of the regulation is to control and abate carbon air pollution, not to generate revenue. Rather than impose a tax, the regulation requires the issuance of allowances by the department to CO_2 budget units. An allowance is a limited authorization by the department under the trading program for CO_2 budget units to emit up to one ton of CO_2. Allowances are then traded within the confines of a consignment auction. No money is generated for or sent to the state.

	board's authority or RGGI, are designed to produce revenue to fund energy efficiency programs, resiliency infrastructure, and other government purposes. The overlay of the additional cost imposed by the auction of CO_2 emission allowances constitutes a tax. The magnitude of that tax will not be set by Virginia; it will be set by RGGI, a non-governmental entity. The General Assembly may delegate the power of taxation to any county, city, town, or regional government (Va. Const. art. VII, § 2). However, the General Assembly cannot delegate its taxing power to an unelected entity, whether the board, DEQ or RGGI. The Constitution and case law are quite clear on these matters. Although the Constitution does not explicitly prohibit the delegation of such decisional authority concerning the imposition of taxes, that delegation is prohibited by necessary implication, and the General Assembly may not delegate its taxing power to a non-elected body. Thus, the Virginia Constitution prohibits ceding tax power to the board, DEQ or RGGI.	
63. AdvanSix, Greif, ODEC, Virginia Manufacturers Association (VMA)	The program is unnecessary. Virginia's per capita energy use fell from a peak of 346 MBtu per person in 2005 to 292 MBtu in 2013 and 2014. Virginia's 2014 rate is lower than the national average of 309 MBtu and ranked Virginia 21st among U.S. states for energy consumption. The decrease in energy consumption translates into a decrease in CO_2. From 2000-15, Virginia's energy-related CO_2 fell by 16.3%; the RGGI states averaged a 17.1% decrease and the entire U.S. experienced a 10.3% drop. Virginia already generates a relatively low amount of GHGs from electrical power generation, transportation, heating/cooling, and industrial processes. Virginia's CO_2 emissions decreased from 15.9 tons per person in 2005 to 12.5 tons in 2014. This was substantially better than the national average of 17.0 tons per capita and ranked 13th best in the country. Virginia is reducing its carbon footprint at a rate better than the nation and comparable to the RGGI states even without a cap-and-trade program. Virginia's electric utilities are expanding the role of renewable energy in power generation. Dominion has solar facilities capable of producing approximately 744 MW of power either operational or under development. ODEC has approximately 300 MW of renewable energy generation capacity, and plans to add 70 MW of solar generation in the next 5 years. As technology costs decrease, solar electric generation is growing rapidly in Virginia. According to the Solar Energy Industries Association, Virginia's total solar capacity of 619.5 MW at the end of 2017 ranked 17th among the states. SEIA data indicate that Virginia's solar generation fleet grew by 381.3 MW in 2017. Virginia ranked 10th in the nation last year in adding solar capacity. Dominion's 2017 IRP calls	The program is needed. DEQ's modeling analysis suggests that carbon emissions from the electricity sector will increase without the program. The analysis is consistent with similar analyses conducted by the federal Energy Information Agency (EIA) showing emissions generally flat or modestly increasing in the coming years and decades. While emissions have decreased in some recent years, that trend is reversing and emissions are expected to continue to increase without the trading program. The commenter is correct that renewable energy development is expanding in Virginia, and it is expected that this trend will continue. DEQ has also recognized the value of these types of programs by establishing the 5% set-aside. New renewables and energy efficiency will make compliance with the trading

	for the addition of at least 3,200 MW additional solar capacity by 2032 and at least 5,280 MW additional solar capacity by the end of a 25-year study period concluding in 2042. Dominion is moving forward with a project consisting of two, 6-MW turbines that will become the mid-Atlantic's first offshore wind project in a federal lease area. Larger-scale deployment of turbines in an adjacent site could potentially produce up to 2,000 MW of electricity. SB966 (2018), states that construction or purchase by Virginia electric utilities of solar and wind-powered facilities capable of producing up to 5,000 MW of electricity at maximum output is "in the public interest." It is clear that Virginia's electric utilities are moving rapidly to greatly expand generation from renewable resources. Virginia is already among the nation's leading states in this regard. A costly CO_2 program is unnecessary to promote the continued rapid growth of renewable energy generation in the state.	program easier, but neither new renewables nor energy efficiency guarantee an emissions reduction from the sector. The program does.
64. AdvanSix, Greif, ODEC, Virginia Manufacturers Association (VMA)	Virginia's electric utilities have billions of dollars invested in assets that serve the public good and generate returns for investors. If the program fails to allocate allowances necessary for those facilities to generate electricity, that failure would deprive those entities of their ability to operate. In essence the government would be taking the value of those electric generating assets from Virginia's utilities without public need and compensation. Similarly, if sufficient allowances for Virginia's utilities to operate are allocated but then forced to be consigned to RGGI for potential purchase by someone else, the board would be taking valuable allowances away from these companies without public need and compensation. Such "takings" are prohibited by the U.S. and Virginia Constitutions. Virginia is a member of numerous interstate and regional compacts. An essential feature of these compacts is authorization by the U.S. Congress and confirmation by the General Assembly. Linking to RGGI by compelling the consignment of allowances to RGGI for general auction would constitute an unauthorized compact with the RGGI states. Attempting to do so would exceed the authority of the board. Emission allowances should be allocated without cost to EGUs that will be constrained by the emissions cap. Direct auction of the allowances with the revenue collected by the state would constitute a tax. A direct auction would greatly increase the cost of the program to Virginia citizens and businesses.	DEQ disagrees with the commenter's assertion that the allocation of allowances constitutes a taking of value. As described in 9VAC5-140-6050 C 9, a CO_2 allowance does not constitute a property right. The allocation of allowances in no way deprives electricity generators of their ability to operate. That would defeat the purpose of the emissions trading program. Allowances are allocated based on actual generation (versus static historical generation), thus providing facilities with greater flexibility. Linking to RGGI does not constitute entering a compact. RGGI is a cooperative venture, governed by consensus among member states to maximize collective emissions reductions capabilities. Linking to RGGI does not exceed any federal or state requirement, nor does it directly impose any legal

		requirements on Virginia or its regulated community. As discussed in the response to comment 76, the board has the legal authority to control carbon pollution. Linking to RGGI is the most cost effective and efficient means of accomplishing this goal.
65. AdvanSix, Greif Packaging, Virginia Manufacturers Association (VMA)	Fossil fuel-fired units that serve electrical generators smaller than 25 MWe and industrial facilities should not be included in the proposed program. ED 11 speaks in terms of "electric power facilities," and EO 57 speaks in terms of "power plants," "the electric sector," "electric companies," and "electric utilities." It is clear that the mandate from then-Governor McAuliffe was for the board to propose a CO_2 cap-and-trade program tied to RGGI that would apply to facilities whose primary, if not exclusive, purpose is the generation of electricity for sale to the public. Industrial facilities are not power plants owned by electric companies and operating in the electric sector, and are clearly outside the scope of EO 57 and ED 11. Many industrial facilities in Virginia do not have multiple locations with different energy generating capacities to provide flexibility in meeting a CO_2 emissions cap. They have one facility and cannot shift allocations between facilities and generating technologies. Virginia's electric utilities have multiple units and generating technologies which allow them to find the least expensive way to reduce CO_2 emissions. Utility power producers are in the business of building alternative power generation sources while manufacturers are not. It is easier for utility power producers to shift the mix of generation to renewable power. Electric utilities have economies of scale and may purchase larger and a greater number of alternative generation units. Manufacturers' power needs are generally much smaller. Electric utilities are better able to pass their costs on to their customers, while manufacturers do not have a captive customer base. They compete worldwide for business from customers who are acutely price sensitive. Large capital expenditures for alternative energy generation would increase the price of products and damage their market position. Electric utility revenues are not affected by these global market demands. Emissions from industrial sources comprise only 11.3% of Virginia's CO_2 emissions. Expanding cap-and-trade to the manufacturing sector would impose significant costs with only a small reduction in emissions. The regulation does not define "primary use." The dictionary sense of "primary" would allow a facility to	DEQ agrees with the commenter's characterization of the directive to control carbon emissions from fossil fuel-fired generators. The ED 57 Work Group specifically recommended that the Governor consider taking action via a regulatory process to establish a trading-ready carbon emissions reduction program for fossil fuel-fired electric generating facilities. In the RGGI Model Rule, facilities that provide less than 10% of their power output to the grid are exempted from compliance obligations. DEQ also evaluated dedicated electricity generating units serving industrial facilities in Virginia, and determined that those facilities would not qualify as CO_2 budget sources. These facilities are already subject to a stringent permitting process to control criteria and toxic pollutants, and are closely monitored in order to ensure that they are meeting state requirements for controlling those emissions. Exemption of this level of industrial producers is also consistent with the RGGI model rule. The proposal has been amended to remove the phrase "owned by an

	export just under 50% of the electricity and heat generated from fossil fuels on site and still qualify for the exemption. The reality is that no manufacturing facility comes close to exporting 50% of the energy generated on site. However, the regulation should provide manufacturing facilities a margin of flexibility to export energy when it is not all needed on site. "Primary use" should mean that in order to qualify for the exemption, no more than one third of the power generated on site, in the form of electricity and heat, can be exported. This approach is based on the cogeneration exclusion in Virginia's CAIR rule. For example, 9VAC5-140-1040 B 1 a (2) excluded cogeneration units provided they did not supply more than one third of the unit's potential electrical output capacity to any utility power distribution system for sale.	individual facility." This change is being made in order to ensure that facilities are not penalized for employing more energy efficient and less polluting generating systems that may be operated by a third party on behalf of the primary facility. The proposal has also been modified to set a threshold for what constitutes "primary use of operation of the facility." These changes are necessary in order that the applicability provisions be consistent with RGGI's 2017 Model Rule. Note that ongoing program reviews will provide the opportunity to adjust the exemption if necessary. There may also be opportunities in separate future rulemakings to directly address the exemption should implementation issues be identified.
66. Virginia Advanced Energy Economy (AEE)	AEE supports a CO_2 budget trading program. The regulation will help to make Virginia's energy more secure, clean, and affordable, bolstering the state's economy while reducing emissions. We support the ability of the regulation to integrate into other carbon markets. Integration with other states and regions will help Virginia achieve greater efficiencies and further reduce emissions. Utilizing the State Tool for Electricity Emission Reductions (STEER), AEE analyzed possible compliance pathways. With a diverse portfolio of advanced energy resources, including renewables and energy efficiency, the state could reduce emissions by over 13.3 million tons between 2020-30 at little to no cost, far surpassing the proposed targets. We recommend a 2020 baseline at or below 33 million tons. Lowering the baseline may encourage system planners and grid operators to accelerate the deployment of advanced energy resources in preparation for the 2030 targets. Such accelerated deployment is beneficial to ratepayers, as it would take advantage of the federal production tax credit for wind and the investment tax credit for solar and other advanced energy technologies.	Support for the proposal is appreciated. DEQ recognizes the value of the renewable energy market and energy efficiency measures as important tools in reducing carbon pollution. The program will promote both renewables and energy efficiency by putting a price on carbon emissions. The program effectively encourages renewables and efficiency because they are carbon-free resources and do not have a compliance obligation, unlike carbon-emitting resources. DEQ also recognizes that CHP units are highly efficient, and do not encourage the development of fossil fuel-fired generation.

	These incentives lower the costs of renewable resources, savings that will be passed along to consumers. Given the cost-effectiveness of energy efficiency, the sooner it is deployed the greater the cumulative savings will be to ratepayers. Our modeling also indicates that with a portfolio of advanced energy technologies in conjunction with coal-to-gas switching, Virginia can beat its 2030 carbon reduction target by approximately 3.4 million tons. These results suggest that actual reductions will exceed targets. When emissions reductions outstrip targets it has the effect of lowering the price of a carbon credit. While keeping the price of credits in check is preferable, significantly depreciating them is not, as it depresses the market and introduces volatility. We support the CCR and the ECR as they ensure that carbon prices remain within a predictable range. However, we prefer predictable and robust prices established and maintained through the market, as opposed to out-of-market interventions. Such prices are essential to the effective financing of advanced energy projects. We recommend that the rate at which the cap decreases each year be 4% annually, and that the ECR and CCR be adjusted correspondingly. These changes will help ensure that targeted and achieved reductions move in closer alignment, and that market functions proceed smoothly. Under the proposal, all permits are allocated to generators (less the set-aside) based on a 3-year average of net generation. We approve of basing allocations on generation, as opposed to historic emissions, as well updating allocations over time. To encourage compliance, we recommend that the rule allocate allowances to all generating units equal to or greater than 25 MW regardless of technology. This will ensure that the allowance allocation remains technology neutral and encourage competition among emission reduction measures. CHP units that generate heat and power for an individual facility are exempt. Given the efficiency of such systems, and the corresponding emissions benefits, this exemption is reasonable. We recommend that "owned by an individual facility" be removed. This will ensure that CHP systems that serve an individual facility are exempt regardless of ownership status. In order to ensure that the "primary use" of the CHP system is indeed to serve the individual facility, the regulation should specify that a minimum of 85% of the useful energy output be used at the site. As proposed, a covered CHP system must account for emissions created in the production of electricity and useful thermal energy (UTE). However,	The program achieves its primary environmental objective through the cap, and not the allocation method. Note, however, that the updating output-based allocation methodology will reward units that produce more electricity with lower carbon emissions. In the past, DEQ has always allocated allowances to compliance entities and not to other entities, with the exception of set-asides to promote energy efficiency. This program takes a similar approach. The structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement that set-aside. DEQ believes the set-aside should be 5% in the early stages of the program, and this percentage is consistent with past DEQ programs. The set-aside may be revised at a later date as the state gains experience with the program and with the program DMME develops. DEQ agrees that the phrase "owned by an individual facility" should be removed. Under the RGGI Model Rule, facilities that provide less than 10% of their power output to the grid are exempt from compliance obligations; the proposal has been revised accordingly.

	absent a CHP system, such thermal energy would be generated through a conventional method that is not subject to the regulation, potentially discouraging the use of CHP while creating new emissions from non-covered sources. The UTE exemptions put forward by other states should be considered. AEE supports the 5% set aside for DMME. According to studies by EPRI, by 2030 energy efficiency programs have the potential to save Virginians over 23,000 GWh of generation, more than 17% of the state's load, each year. On Virginia's current trajectory, the state will achieve just 5% of that potential. This underperformance stems from underinvestment in energy efficiency and a misalignment of incentives. Until this misalignment is reformed we support allowing experienced parties the ability to implement programs in addition to the utilities. We recommend doubling the set-aside to 10% in order to provide a more robust financing stream. According to our modeling, energy efficiency has the potential to help Virginia meet its carbon mitigation targets while reducing rates, creating jobs, and stimulating new in-state investment. The challenge energy efficiency presents lies in the ability of system planners, regulators, and other stakeholders to effectively track, evaluate, measure, and verify the energy savings produced by an array of energy efficiency programs and measures. The National Energy Efficiency Registry (NEER) helps states track and verify energy efficiency savings and transform those savings into tradable instruments parties may then use for compliance. Regulators and stakeholders should use NEER to facilitate the administration and tracking of energy efficiency programs in Virginia. Employing consistent and well-established methods for evaluation, monitoring, and verification of savings will help Virginia effectively tap into this cost-effective resource. Voluntary purchasers of renewable energy do so in part based on carbon reduction benefits. In many states, the purchase of a REC includes the purchase of environmental attributes associated with the carbon reductions of that power. Unless the voluntary market is taken into account, a statewide carbon reduction requirement could undermine voluntary purchaser commitments because they will no longer represent a regulatory surplus. Several programs have avoided this through a voluntary purchaser set-aside. This can also be done by allocating allowances to resources that reduce emissions rather than only to emitting resources. This will allow advanced energy resources to fulfill any contracted-for obligations to transfer allowances to purchasers under existing power purchase agreements. Those purchasers can then choose to do what they wish	

	with the allowances. This gives purchasers the choice to retain these allowances if they wish to preserve the project's regulatory surplus.	
67. American Forest and Paper Association; American Wood Council; Forest Products Industry National Labor Management Committee; Virginia Agribusiness Council; WestRock	The following principle should be incorporated into the regulation: "Emissions from the combustion of any forest-derived biomass shall not be considered a GHG if: 1) timberland carbon stocks, based on U.S. Forest Service Forest Inventory and Analysis data for the U.S. South Region, are stable or increasing relative to the 2005 carbon stocks assessment for this region; or 2) the forest-derived biomass is from forest products manufacturing residuals, harvest residues, or waste-derived feedstocks, including used wood products." Subsection 1 is based on the fact that harvesting wood for energy does not contribute to net carbon emissions in cases where it is offset by wood growth and associated carbon sequestration. U.S. Forest Service data shows carbon stocks in trees on timberland across the southern U.S. have increased from 4.9 billion tons in 2005 to 5.6 billion tons in 2016. This shows biogenic CO_2 from biomass removed from the forest is more than offset by removals of CO_2 from the atmosphere by growing forests. Also, 2016 data from the U.S. Forest Service demonstrates that the growth/removal ratios for timberlands in Virginia is 2.29, meaning timberlands are growing more than twice as much wood as is being harvested. This positive net growth/removal ratio shows that Virginia forestry is more than sustainable. Finally, strong markets for wood preserve forests by providing an incentive not to convert the land to other uses. Subsection 2 is based on the fact that emissions from forest products manufacturing residuals, harvest residues, or waste-derived feedstocks would eventually enter the atmosphere even if they are not used for energy production. Simply landfilling these feedstocks can result in methane emissions, which have a much greater impact on global warming than CO_2. The use of biomass residuals each year avoids the emission of approximately 181 million tons of CO_2 indicating there are GHG reduction benefits in using forest products residuals for energy in the pulp, paper, packaging and wood products industry.	DEQ is well aware of the concerns associated with biomass, and discussed the pros and cons of including or excluding biomass units with the Regulatory Advisory Panel established to advise and assist in the development of the regulation. The group did not reach consensus on an approach for dealing with biomass; given that, and given the numerous, detailed comments received during the public comment period, DEQ recognizes that this is a polarizing subject. However, the ED 57 Work Group specifically recommended that the Governor consider taking action via a regulatory process to establish a trading-ready carbon emissions reduction program for fossil fuel-fired electric generating facilities. The RGGI Model Rule provides that a biomass-fired facility may be a CO_2 budget source if the use of fossil fuel combusted comprises, or is projected to comprise, more than 50% (commence operation pre-2005) or 5% (commence operation post-2005) of the annual heat input on a Btu basis during any year. DEQ evaluated the fuel mix of the 5 potentially affected biomass-fired facilities in Virginia, and determined that those facilities would not qualify as CO_2 budget sources. These biomass-fired facilities are already subject to a stringent

		permitting process to control criteria and toxic pollutants, and are closely monitored in order to ensure that they are meeting state requirements for controlling those emissions. Additionally, most RGGI states allow CO_2 budget units that co-fire eligible biomass to deduct CO_2 emissions attributable to the burning of eligible biomass from their compliance obligation in accordance with the RGGI model rule. Finally, periodic program reviews at the RGGI and state level will provide opportunities to adjust the exemption should implementation issues be identified. The proposed definition of "fossil fuel-fired" is inconsistent with the RGGI 2017 Model Rule, which sets a threshold of 5% of the annual heat input on a Btu basis during any year, and the regulation has been amended accordingly. This change is necessary in order to ensure that Virginia's regulation is a corresponding CO_2 Budget Trading Program regulation, such that Virginia can be considered a RGGI Participating State; the proposal has been amended accordingly.
68. American Forest and Paper Association; American Wood Council (AF&PA and AWC)	AF&PA and AWC do not support Virginia joining RGGI because it will raise electric power prices and consequently cause Virginia-based businesses to become less competitive. Biogenic CO_2 emissions from forest-derived bioenergy should be counted as making zero contribution to the build-up of GHGs in the atmosphere where timberland	The commenters' concerns are recognized. As discussed in greater detail in the response to comment 61, potential costs and benefits have been rigorously examined, and the program has been

	carbon stocks are stable or increasing. Through the natural carbon cycle, growing forests sequester carbon as trees are replanted and grow through their lifecycles, even as some trees are harvested. Recent data from the U.S. Forest Service indicate that timberlands in Virginia, the U.S. south, and the entire U.S. have positive net growth/removal ratios. Virginia's timberlands are growing more than twice as much wood as is harvested. The most significant pressure on forests is conversion to non-forest uses, such as development. By contrast, strong markets for wood help to preserve forests by providing an incentive to not to convert land to other uses and to invest in healthy forest management practices. A Journal of Forestry article concluded that "[t]he demand for wood keeps land in forest, provides incentives for expanding forests and improving forest productivity, and supports investments in sustainable forest management that can help offset the forest carbon impacts of increased demand." A U.S. Department of State report shows that strong demand for forest products will increase forest carbon stocks through ongoing landowner investment. Paper and wood products mills rely on residuals from the manufacturing process for steam and power for their operations or to sell electricity to the grid, and there is consensus that the use of residuals and biowastes for energy has significant GHG reduction benefits. A study published in the Journal of Industrial Ecology concluded that "[T]he use of biomass residues from forest products manufacturing, including black liquor, to produce energy in the U.S. forest products industry for 1 year avoids, over a 100-year period, 181 million tons of CO_2-equivalent emissions per year. Even ignoring the displacement of fossil fuels such as coal, the article finds that the avoided disposal of forest products manufacturing residues alone produces a GHG reduction benefit of approximately 5 million t CO_2-eq/yr." This is equivalent to removing one million cars from the road. The article states that ". . . if mill residues were not used for energy, most of these materials would be wastes that would be either incinerated, in which case the atmosphere would see the same biogenic CO_2 emissions as if the material had been burned for energy, or disposed in landfills." Disposal of residues in landfills creates methane, which has about 28 times greater global warming potential than CO_2. The article concludes, "consider[ing] all GHGs and fossil fuel substitution, the overall [GHG reduction] benefits of using manufacturing residuals for energy are large and become evident in short periods." Forest biomass, including manufacturing residuals, should be treated as carbon neutral whether or not it is co-fired with fossil fuel. The carbon profile of biomass is not altered simply because it is co-fired. This distinction	designed to provide the maximum benefit at the least possible cost. See the response to comment 67 for further discussion of how biomass will be treated under the program and the response to comment 65 for further discussion of industrial boilers.

	is not scientifically supportable given that the biomass portion of the fuel mix has the same characteristics regardless of whether it is co-fired with 9% fossil fuel, 10% fossil fuel, or 90% fossil fuel. It is the biomass portion of the fuel mix alone that should be evaluated for net carbon emissions. The regulation should not cover industrial boilers. ED 11 pertains exclusively to controlling CO_2 emissions from "electric power facilities." Likewise, EO 57 directed the Work Group to recommend methods to reduce CO_2 emissions from "electric power generation facilities." The Economic Impact Assessment, the charge given to the Regulatory Advisory Panel, the emissions and economic modeling conducted by DEQ and its consultants, and DEQ's information leading up to and supporting the proposal indicated that the regulation applied only to the electric power sector. Indeed, covering only utilities is consistent with the intent and scope of the existing RGGI program, and RGGI allowance prices are based on the marginal cost to reduce GHG emissions from the utility sector and do not reflect the capability of industrial sources to reduce emissions. Unlike the electric power sector, industrial facilities must compete in a highly competitive global marketplace and do not have the comparable ability to pass on increased compliance costs to customers. Accordingly, it would be arbitrary and capricious, a violation of due process, and fundamentally unfair for the final rule to include other emission sources, such as industrial boilers. We also urge that the state retain the issuance of free allowances rather than conduct auctions, which would drive up compliance costs and harm the households and businesses served by the power grid.	
69. Appalachian Power/American Electric Power (APCo/AEP)	It would not be in the best interest of the state to develop incremental carbon policies to intervene in an ongoing transformation of the electric sector. Given that the Virginia regulatory process is robust and that CO_2 emissions have trended significantly downward, additional restrictions on carbon emissions could put Virginia at a competitive disadvantage. Unlike the Clean Power Plan, which included all states, a Virginia-specific carbon strategy would distort economic decisions. Carbon restrictions that are more stringent than national standards could lead to existing generating facilities being closed or new facilities constructed elsewhere, leading to a loss of both employment opportunities and tax revenue. The regulation will also result in higher customer rates, which would place additional stress on the finances of households and business, and influence where businesses choose to locate. DEQ has not provided adequate analysis supporting that benefits of the regulation for Virginia citizens would outweigh the costs.	Support for the proposal is appreciated. As discussed in the response to comment 61, Virginia's carbon control strategy is not go-it-alone; the purpose of the regulation is to leverage Virginia's carbon reduction efforts by linking to a well-established and effective multi-state program. DEQ agrees that cap-and-trade programs are effective in controlling emissions. However, as discussed in the response to comment 64, DEQ has designed the program to implement a consignment auction rather than a direct

	APCo is encouraged by the fact that DEQ has proposed a cap and trade program as the regulatory structure. Cap and trade programs have long been documented as effectuating emission reductions at the lowest cost. APCo supports allowance banking and a CCR allowance should allowances costs exceed projections. This is a fair way to ensure that consumers and businesses are not unduly burdened. APCo does recommend that several aspects of the regulation be modified. First, DEQ has not provided an adequate rationale for use of a consignment auction. Cap and trade programs have been overwhelmingly successful with a direct allocation to affected sources. Second, the allocation mechanism for allowances on the basis of updating net generation output does not acknowledge the inherent differences in carbon emissions between units utilizing different fossil fuels. Units using fuels with a higher carbon content are unfairly disadvantaged by the allocation process, even as they are subject to a declining carbon cap. APCo recommends directly allocating allowances to affected generators on the basis of actual emissions.	auction. This will ensure that Virginia can link to RGGI while accommodating Virginia's unique utility regulatory regimen, and ensure a stable, transparent and fair program. See comments 108 and 136 for further discussion of the appropriateness of the consignment auction.
70. Appalachian Power/American Electric Power (APCo/AEP)	APCo does not support allocation of conditional allowances to DMME. There is no adequate rationale for this set-aside. Under a cap and trade program affected sources and other parties have the incentive to utilize the most cost effective way to comply with the program and/or associated costs. The proposed set-aside effectively represents a 5% tax on affected sources and ultimately consumers and there is no justification that the benefits of this "tax" will justify any benefits that may be provided.	The primary purpose of EO 11 is to control carbon emissions from fossil fuel-fired power plants; however, EO 11 has also identified the encouragement of clean energy as a program goal. A 5% set-aide is modest, and will enable the state to determine the effectiveness of this type of program; see the response to comment 51 for further detail. To characterize the set-aside as a tax is inaccurate as discussed in the response to comment 62.
71. Appalachian Power/American Electric Power (APCo/AEP)	Inclusion of new units will be a disincentive to siting new fossil generation within Virginia as these units would be subject to an incremental cost associated with complying with the regulatory program. As such, units could be more cost effectively built in adjoining states not covered by the Virginia program, thus depriving the state of jobs and tax revenue associated with new generation facilities.	Inclusion of new sources is consistent with the RGGI program. In order for carbon reduction efforts in Virginia to succeed over the long term, new fossil fuel sources in the state must be considered. DEQ is confident that leakage will be addressed by a variety of RGGI and Virginia mechanisms; see comments 91, 108, 136 and 144 for more detail.

72. Appalachian Power/American Electric Power (APCo/AEP)	APCo has concerns with the need to maintain a new Virginia-specific database for GHG emission reporting, operating and maintaining a new database and software program for allowance trading, and maintaining records associated with CO_2 emissions and accompanying reports. APCo already maintains systems for emissions reporting and record retention per federal requirements, which differ significantly from those Virginia has proposed. Better aligning the proposed reporting, trading and compliance programs with the federal systems already in place would reduce the administrative burden of the rule.	Because Virginia is linking to an existing trading program, it is not anticipated that any new Virginia-specific database will be needed. The Commonwealth is expected to use the RGGI COATS system to track allowances and emissions. The COATS system accepts emissions reporting consistent with federal requirements and is connected to EPA's emissions reporting system.
73. Appalachian Power/American Electric Power (APCo/AEP)	The higher starting cap of 34 million tons of CO_2 would mitigate the economic impact of the regulation. The higher cap would have imperceptible impact on the environmental effectiveness of the program with the benefit of lower resulting compliance costs.	The starting cap will be 28 million tons; see the response to comment 37 for more information.
74. Alliance for Industrial Efficiency	We commend DEQ for developing this regulation. Our members support market-based programs like RGGI because they account for the cost of carbon emissions while promoting economic growth. The regulation provides Virginia the opportunity to capture the economic benefits of transitioning to a low carbon economy. We applaud DEQ for recognizing the most economically efficient means for reducing CO_2 emissions in Virginia: incentives for energy efficiency. Finally, we commend DEQ for exempting certain industrial CHP units, which recognizes the emissions benefits offered by these systems. CHP systems produce heat and electricity from a single fuel source. Instead of generating power and letting the waste heat escape, CHP systems harness the thermal energy for heating, cooling, and other applications. Waste heat to power systems capture waste heat from industrial processes to make electricity, requiring no additional fuel and generating no further emissions. Not only does CHP have higher efficiencies than conventional power generation, it produces energy at the site of the end user, which eliminates line losses. CHP also provides benefits besides energy savings and resiliency and reliability benefits--it can continue to function in the event of a grid disruption. CHP should be a key element of the state's broader efforts to modernize its electric grid and make it more reliable. The General Assembly recognized the benefits of CHP in the 2018 omnibus energy bill which directs utilities to consider CHP as either a demand-side energy efficiency measure or a supply-side generation alternative.	Support for the proposal is appreciated. As discussed in the response to comment 51, DEQ believes the set-aside should be 5% in the early stages of the program; the set-aside may be revised at a later date as the state gains experience with the program and with the program DMME develops. In order to address CHPs with more clarity, the regulation has been amended to specify that the industrial exemption applies to fossil fuel CO_2 budget source located at a manufacturing facility that supplies less than or equal to 10% of its annual gross electrical generation to the electric grid, or supplies less than or equal to 15% of its annual total useful energy to an entity other than a manufacturing facility, provided that source had, prior to January 1, 2019, supplied

	The regulation requires that CHP units over 25 MW that do not qualify for the industrial exemption purchase CO_2 emissions allowances for all emissions, including those associated with useful thermal energy (UTE). In the absence of a CHP system, the host would get its thermal energy from conventional methods, such as standalone boilers, which are not subject to the regulation. To avoid this disincentive for CHP, the regulation should exclude CO_2 emissions associated with UTE from a CHP unit. Emissions associated with thermal energy should be deducted from a qualifying unit's total emissions allowances, as in Massachusetts' RGGI rule. The hallmark of a CHP system is that it produces heat and electricity from a single fuel source. Without a thermal exemption, the regulation undervalues the output of these systems. We commend DEQ for including an energy efficiency set aside, as such programs help consumers and businesses use less energy, reduce carbon emissions, and save money on energy bills. According to an Alliance for Industrial Efficiency analysis, if Virginia achieves a 1.5% annual energy savings target, the state can reduce annual CO_2 emissions by 2.6 million tons in 2030 and save businesses $4.1 billion in cumulative cost savings from avoided electricity purchases. Increasing the set-aside from 5% to 10% would create additional opportunities for energy efficiency programs and help capture more carbon reduction benefits. For example, EPA's guidance document on Establishing an Energy Efficiency and Renewable Energy Set-Aside in the NO_X Budget Trading Program recommends a set-aside of 5-10%. We recommend that DEQ clarify that energy efficiency includes CHP and would be eligible for set aside funds. Although DEQ has previously categorized CHP as a near-term energy solution to enhance energy efficiency, listing CHP incentives explicitly as eligible for set aside funds would ensure that potential project hosts are aware of the definition.	both non-electric thermal energy to a manufacturing facility and 15% or less of its annual total useful energy to an entity other than a manufacturing facility. The unit's permit must contain a condition with the appropriate restriction of either gross electrical generation or useful thermal energy.
75. Dwight Alpern	I support the proposed rule. I was the attorney-advisor for EPA's Clean Air Market Division and involved in developing regulations for allowance trading programs, including the Acid Rain Program and NO_X SIP Call. I suggest revisions to facilitate program operation and achievement of CO_2 reductions. 1. The proposal does not explain clearly how a holder of a public contract with DMME would set up and operate a conditional allowance account. The function of such an account would be similar to that of any general account established by other persons, i.e., holding and transfer of CO_2 allowances. Neither account's function would	Support for the proposal is appreciated. The commenter correctly notes that the proposed rule does not explain how a holder of a public contract with DMME would set up and operate a conditional allowance account. This process will be determined by DMME in accordance with DMME procedure. Because this process will

	include holding allowances for compliance. The simplest approach would be to revise the rule to clarify in 9VAC5-140-6020 C that accounts for handling conditional allowances are a type of CO_2 Allowance Tracking System account (in revised definitions of "CO_2 Allowance Tracking System" and "CO_2 Allowance Tracking System account") and that those accounts of holders of public contracts with DMME (but not of CO_2 budget sources) are general accounts (in a revised definition of "general account"). This would make applicable to the public contract holders' accounts the general-account provisions, e.g., for applying for an account and selecting and changing an authorized account representative, alternate, and electronic submission agent. Conforming revisions should be made to 9VAC5-140-6220 A, 9VAC5-140-6230 A, 9VAC5-140-6240, and 9VAC5-140-6250 A and B. For example, proposed 9VAC5-140-6230 A should be revised to read: Upon receipt of a complete account certificate of representation under 9VAC5-140-6110 or subsection B of this section, the department or its agent will establish a conditional allowance account and a compliance account for each CO_2 budget source or ~~and~~ a conditional allowance ~~compliance~~ account for a holder of a public contract with DMME for which the account certificate of representation was submitted. 2. The proposal requires Virginia CO_2 budget sources to hold "CO_2 allowances" for CO_2 emissions (9VAC5-140-6050 C 1 and 2 and 9VAC5-140-6260 B) but defines the term "allowance" (9VAC5-140-6020 C) by referring only to the Virginia CO_2 Budget Trading Program. That definition should be expanded to include CO_2 allowances issued by any other state participating in the RGGI program. If DEQ also decides to allow Virginia CO_2 budget sources to use for compliance offset allowances issued by any participating state, the same limitations on the use of offset allowances by other RGGI states' sources should apply to Virginia sources, i.e., limited use to cover emissions and no use for excess emission deductions. If offset allowances are to be usable, the following revisions are suggested: 9VAC5-140-6260 1. The CO_2 allowances, other than CO_2 offset allowances, are of allocation years that fall within a prior control period, the same control period, or the same interim control period for which the allowances will be deducted. ***3. For CO_2 offset allowances, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an interim control period may not exceed 3.3% of the CO_2 budget source's CO_2 emissions for that control period, or of 0.50 times the CO_2 budget	be governed by DMME, it is more appropriately addressed by DMME and not in this regulation. With respect to allowances usable for compliance, the definition of an allowance has been modified such that it covers any other state participating in the trading program.

	source's CO_2 emissions for an interim control period, as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) of this part and Article 8 (9VAC5-140-6330 et seq.) of this part. 4. The CO_2 allowances are not necessary for deductions for excess emissions for a prior control period under subsection D of this section. 9VAC5-140-6260 C 2. The department or its agent will deduct CO_2 allowances for a control period from the CO_2 budget source's compliance account, in the absence of an identification or in the case of a partial identification of available CO_2 allowances by serial number under subdivision 1 of this subsection, as follows: i. First, subject to the relevant compliance deduction limitations under subsections A and D of this section, CO_2 offset allowances. CO_2 offset allowances shall be deducted in chronological order (i.e., CO_2 offset allowances from earlier allocation years shall be deducted before CO_2 offset allowances from later allocation years). In the event that some, but not all, CO_2 offset allowances from a particular allocation year are to be deducted, CO_2 offset allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances. ii. Second, any ~~Any~~ CO_2 allowances, other than CO_2 offset allowances, that are available for deduction under subdivision 1 of this subsection. CO_2 allowances shall be deducted in chronological order (i.e., CO_2 allowances from earlier allocation years shall be deducted before CO_2 allowances from later allocation years). In the event that some, but not all, CO_2 allowances from a particular allocation year are to be deducted, CO_2 allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances. 9VAC5-140-6260 D 1. After making the deductions for compliance under subsection B of this section, the department or its agent will deduct from the CO_2 budget source's compliance account a number of CO_2 allowances equal to three times the number of the source's excess emissions. In the event that a source has insufficient CO_2 allowances to cover three times the number of the source's excess emissions, the source shall be required to immediately transfer sufficient allowances into its compliance account. No CO_2 offset allowances may be deducted to account for the source's excess emissions.	
76. Americans for Prosperity	The regulation requires electric generators to purchase allowances to emit CO_2 in the RGGI cap-and-trade program. These allowances are equivalent to permit or license fees. In addition, the regulation delegates 5% of the allowance proceeds to DMME for CO_2 reduction projects. The Constitution of Virginia establishes	To characterize the issuance of an allowance as a permit or license fee is inaccurate; see the response to comment 62. Facilities have always

	authority to raise and spend money to the General Assembly, not DEQ (Article IV, § 11 and Article X, § 7). The regulation adopts the RGGI Model Rule, model legislation which has been adopted by the legislatures of all participating RGGI states. The General Assembly clearly opposes adoption of a CO_2 cap and trade program without legislative approval. The Senate and House passed HB1270 resolving that no CO_2 cap and trade program be adopted without authorization. In addition, the Senate Agriculture, Conservation and Natural Resources Committee rejected SB696, which would establish cap-and-trade in Virginia and bring the state's regulations into compliance with the RGGI model rule. The proposed regulation will not withstand a legal challenge.	incurred costs as they have been required to meet legal mandates to control and reduce pollution. Under a cap-and-trade program, facilities have enhanced flexibility to manage these compliance costs based on their specific business needs. As discussed in comments 139 and 159, it is necessary and appropriate for the board to promulgate state-specific regulations controlling carbon pollution. The board's legal authority to issue regulations controlling air pollution is found in the Code of Virginia at §§ 10.1-1306 through 10.1-1308; the Office of the Attorney General of Virginia issued an official advisory opinion on May 12, 2017, which concluded that the board is legally authorized to regulate carbon pollution under these sections of the code. While the board has broad authority to control air pollution, it is also responsible for achieving this goal in the most effective and cost-effective means possible, and, in the case of carbon pollution, this goal is most readily achieved through implementation of a cap-and-trade program. Cap-and-trade programs are proven means of reducing air pollution (see, for example, the response to comment 48); they incentivize pollution reduction. Unlike a "command-and-control" approach that would simply impose specific pollution

		control requirements, the trading approach maximizes the ability of a facility to flexibly make favorable business decisions while meeting the primary goal of reducing air pollution. The board furthermore has the authority to maximize the efficiency and efficacy of a cap-and-trade program by linking the program with RGGI rather than attempting to establish a new and untried state-only system. There is nothing novel about Virginia's participation in a cap-and-trade program; indeed, the Commonwealth has participated in such programs since EPA established the Acid Rain Trading Program under Title IV of the 1990 amendments to the federal Clean Air Act. Currently, Virginia is operating under the latest iteration of EPA's trading program for the control of NO_X under CSAPR. Nor is there anything novel about the regulation of carbon pollution in Virginia. Virginia's greenhouse gas permitting regulation (9VAC5-85) has been in place since 2011.
77. Americans for Prosperity	The RGGI program has not worked to reduce CO_2 emissions. CO_2 emissions fell just as fast in states with similar energy policies except for RGGI as they did in RGGI states according to "A Review of the Regional Greenhouse Gas Initiative" (Cato Journal 2018). Lower natural gas prices and EPA regulation encouraged fuel switching from coal to natural gas between 2007-15. This resulted in a 16% reduction in coal-fired electric generation, and a corresponding increase in natural gas generation of about 10% in RGGI and non-RGGI states. The same report shows non-RGGI states added generation from wind, and solar power at over twice the rate as RGGI states (5.5% compared to 2.3%). Non-	The RGGI program has been very successful at reducing emissions in participating states. Current emissions are approximately 45% lower than where RGGI started. Commenters argue that RGGI did not bring about the reductions but offers no evidence to demonstrate that RGGI did not cause—or at least contribute—to

	RGGI states also saw a faster rate of improvement in energy intensity, a measure of energy efficiency (11.5% compared to 9.6%). RGGI, Inc. claims allowance revenue was invested in energy efficiency, and wind and solar power, but the actual comparison results show no significant impact of the investments. Compare non-RGGI Virginia to the combined results in neighboring RGGI states of Maryland and Delaware. All three are in the PJM Interconnection Regional Transmission Organization. The extra costs of RGGI allowances discouraged electric generation in Delaware and Maryland where electricity imports grew 42% since 2005, while Virginia imports decreased 34%. In other words, the RGGI states simply exported electric generation and emissions to other states. Adjusting for those exported emissions, emissions rates per person fell 38.6% in Virginia since 2005 compared to a combined 37.1% for Maryland and Delaware. Importing more power from other states is not the only form of emissions leakage. RGGI allowance costs added to already high regional electric bills. The combined pricing impact resulted in a 12% drop in goods production and a 34% drop in the production of energy intensive goods. Comparison states increased goods production by 20% and only lost 5% of energy intensive manufacturing. The extra costs of RGGI allowances have turned coal-fired plants from base load providers to intermittent suppliers by dramatically lowering operating hours. Expected increases in RGGI emission allowance cost will soon have the same impact on natural gas-fired power plants. Ramping power plants up and down has dropped efficiency 18.5% which results in more emissions, not less, and further raises electricity costs. 61% of Virginia power generation comes from coal and natural gas. A national target of 28% lower emissions from power plants by 2025, and 32% by 2032 from a 2005 base established in the Clean Power Plan will be met without taxes or fees on CO_2 emissions. Over the most recent 12 months power plant emissions have already fallen 27%. The U.S. leads the world in reducing emissions. Since 2005 the U.S. has reduced CO_2 emissions twice as fast as the rest of the developed world combined. Clearly RGGI has not had the expected impact of lowering CO_2 emissions. Benefits calculated in the Economic Impact Analysis assumed the regulation would lower CO_2 emissions along with reducing SO_X and NO_X as a byproduct. A decade of experience with RGGI has shown no added reduction in CO_2 or air pollutant emissions from the RGGI program; therefore there can be no monetized	the emissions reductions in the RGGI region. While the electricity system is complex and it is difficult to separate out specific causes, adjustments to the RGGI program over the years have reduced the RGGI cap, preventing emissions from increasing and locking in reductions. This stands in stark contrast to analyses of uncapped areas of the country where emissions are expected to remain flat or slightly increase into the future. In addition to these demonstrable emissions benefits, as discussed in the response to comment 61, the RGGI program has greatly benefited local and regional economies. DEQ continues to believe that the studies and analyses developed on its behalf as well as additional information provided by RGGI and other experts in the field demonstrate that linking to RGGI will benefit the Commonwealth by cost-effectively reducing carbon pollution and stimulating clean energy growth. See comment 136 for more information on how RGGI's market mechanisms work and how they will operate in Virginia. Note that CO_2 intensity is decreasing across the RGGI region in spite of increased generation. With regard to costs incurred as a result of the CCR, the consignment auction approach means that ratepayers only bear the cost of excess allowances needed to comply.

	benefits from the proposal. To calculate the costs of the regulation an estimate of tons of annual emissions through 2030 is needed, along with an estimate of how many allowances will be available (each allowance covers one ton of emissions), and an estimate of the future price of allowances. Fortunately, the proposal provides the last two items. The SCC files an annual "Status Report: Implementation of the Virginia Electric Utility Regulation Act." The state's two largest investor owned electric utilities Dominion Energy and Appalachian Power file annual Integrated Resource Plans (IRP) which forecast future demand, supply, and pricing. Based on these documents there are planned retirements between 2017-26 of 1731 MW of oil and coal-fired capacity, and 440 MW of natural gas capacity. Between 2017 and 2019 5413 MW of new natural gas-fired capacity has already been approved by the SCC. Natural gas emits about half the CO_2 for each MWh of power generated. The retirements could be considered as offsetting emissions from 4280 MW of new natural gas capacity. That leaves a net increase of 1132 MW of new natural gas capacity. If that new capacity operates 5000 hours a year it will generate about 2.5 million tons of added CO_2. New power plants should yield less expensive power and run more hours than the older replaced plants, meaning higher emissions. Some of the retiring power plants will continue to operate after the new plants start up meaning higher emissions. Appalachian Power and Dominion own out-of-state power plants, and could shift generation out of state, meaning lower Virginia emissions, but global emissions would remain the same. The RGGI states review the program every 3 years and have worked to raise the allowance price each time, so it is likely allowance prices will rise. All of these factors will be ignored in favor of a conservative emission forecast adding 2.5 million tons to the 36.6 million tons emitted in 2016, for a total of 39.1 million tons in 2020. The proposal commits 5% of allowances for sale by DMME with the allowance revenue to be spent on CO_2 reduction projects. The Economic Impact Analysis forecasts an allowance price very close to the proposed ECR trigger price which subtracts allowances offered in an auction if the price goes below the trigger price. Our analysis uses the ECR trigger price as the forecast price. An upper range would use the CCR trigger price which runs about twice the ECR trigger price. If the CCR trigger price is exceeded extra allowances are added to the auction. From 2013-15 the CCR acted as a price signal in the auctions. The forecasted cost assumes power companies chose	

	buy the emission allowances they need to comply to maintain electric grid reliability. The alternative is to write off premature closing of existing plants, while paying premium prices for new zero or low emission generation sources. This is likely as Dominion expects demand to grow 24% by 2030 and will need the capacity. The SCC allows utilities to pass on the cost of meeting environmental requirements and would likely allow the pass through of allowance costs. There is no penalty other than allowance cost if a state misses its RGGI target. The total Net Present Value cost through 2030 of the regulation is $674 million with no offsetting benefits. The cost would be twice as high if the CCR trigger price sends the expected price signal to the auctions, so the range of cost is $0.7-1.4 billion. In 2030, the program will add $182 million, or about $20 a year to residential electric bills. Industrial bills could rise by over $100,000 a year.	
78. Business Council for Sustainable Energy (BCSE)	A regulation to reduce and cap CO_2 through a multi-state trading program makes sense for Virginia. Capping carbon from generation facilities will incentivize the use of cleaner energy resources that promote economic development and job creation in the state. Trading within a larger group of states will allow for greater market efficiency and lower compliance costs. The state will need to use the full portfolio of clean energy technologies and services, including energy efficiency programs that reduce energy consumption, cleaner burning natural gas, and renewable energy resources. BCSE supports the updating output-based allocation structure. DEQ should encourage the use of set asides granted to DMME to support of the full suite of clean energy technologies, including both supply-side and demand-side energy efficiency measures. RGGI states have benefitted from investing the multiyear funding from auction proceeds in clean energy, and BCSE encourages DEQ to consider a larger set aside amount.	Support for the proposal is appreciated, particularly support for the updating output-based allocation structure. As discussed in the response to comment 51, DEQ recognizes the value of energy efficiency programs as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement the set-aside. DEQ believes the set-aside should be 5% in the early stages of the program; the set-aside may be revised at a later date as the state gains experience with the program and with the program DMME develops.
79. Biomass Power Association	Biomass accounts for a significant portion of Virginia's renewable fuels makeup. As of 2015, biomass represented the bulk of renewable power available in the state. We commend the board for pursuing the CO_2 trading program. Only through programs like these can we seriously address the threat of climate change. By supporting a rich combination of power sources, a state can advance goals in other areas like forest management, watershed management, economic development, and transportation.	Support for the proposal is appreciated. See the response to comment 67 for further discussion of biomass.

	The regulation would apply only to fossil fuel fired-facilities, exempting biomass power. We urge Virginia to maintain this position. Aside from supplying the state with a significant portion of its carbon neutral electricity generation, biomass is a critical part of the forestry supply chain. Biomass power facilities purchase the leftovers that remain following the harvest of a forest for higher-value wood fibers, adding value to the entire supply chain. The wood fibers used to generate biomass power are typically unusable for other wood products, and emit methane during decomposition. The Association commissioned a study to determine the extent of carbon savings that can be achieved by opting for biomass over natural gas. A report is available on our website. The study examined the carbon intensity of a 50 MW capacity biomass power facility with a 43 MW net output on the electric grid, comparing it to that of a typical combined cycle natural gas facility. The study found that the use of organic residues as fuel in a biomass power plant instead of natural gas in a combined cycle facility results in immediate carbon savings of 115%, with 98% carbon savings over 100 years. Like the majority of biomass power facilities in the U.S., the subject of the study uses organic residues to generate power supplied to the grid. The fuels used at this facility are residues left over from harvesting fiber for local lumber and paper mills. These low-value materials are generated whether they are used for power or left to decay. If not used by biomass power plants, the materials typically remain in the forest as slash piles. The avoidance of carbon and methane emissions by removing and using materials that decay results in a significant GHG reduction over time. While the decay of these materials releases small amounts of methane consistently over time, methane has a 21 times higher global warming impact on the climate than CO_2. Further, with federal incentives for carbon capture and sequestration, and rapid technological advances being made in this area, biomass with carbon capture can become one of the only viable techniques that allows for the removal of atmospheric carbon. While the technology is still developing, we are optimistic that our members will soon be able to contribute to reducing the impacts of climate change in an even more meaningful way. Biomass is an essential part of any carbon reduction program.	
80. Blue Ridge Environmental Defense League (BREDL), Food and	The excessively high RGGI cap and low allowance clearing prices, combined with other flaws in the program, prevent RGGI from being stringent enough to drive any meaningful reductions in CO_2. RGGI is a weak program that has allowed power plants to emit on a business-as-usual basis. For the first 5 years of the program, the industrywide cap was set over 50% higher	The commenter suggests that RGGI allowance prices have been too "low" to drive emissions reductions. As of July 2018, RGGI allowance prices have remained between $2-4 for

Water Watch, People Demanding Action, Preserve Floyd, Renewable Energy and Electric Vehicle Association	than actual emissions. This meant fossil fuel power plants did not need to do anything to meet the overly generous cap. The initial cap allowed power plants to bank a substantial amount of unused allowances, amounting to 140 million tons of CO_2. While the cap was adjusted to address these saved allowances, this allowance surplus could continue to grow significantly due to a cap that continues to be higher than actual emissions, low allowance clearing prices, the purchasing of all available allowances and other factors. This further limits the effectiveness of the program. The CCR further disincentivizes emissions reductions by operating as a cushion by releasing additional pollution allowances on top of the cap if prices get too high. The CCR was triggered in 2014 and 2015, allowing 5 million and 10 million additional allowances to be sold. All of these allowances were purchased, and because they were not borrowed from future years, they essentially increased the cap. RGGI prices, including the reserve price, continue to be too low or too volatile to result in any meaningful carbon reductions. Most, if not all, of the current carbon markets have failed to create "a stable, market-driven price of carbon," and often prices for GHG allowances "have been so low as to create little incentive to invest in GHG reduction," according to researchers at the University of California. Structural flaws in the RGGI program prevent the purported market-based incentives from working. Moreover, polluters prefer a larger supply of low-priced pollution allowances, creating a disincentive to actually embrace a pollution price point that might be effective. No market-based pollution trading scheme will ever result in market prices sufficient to encourage all polluters to reduce their emissions. RGGI has not accounted for increased emissions of methane from the growth of fracking and natural gas infrastructure. The climate proponents and petroleum industry that favor natural gas contend that since gas-fired plants emit less CO_2 than coal-fired plants, replacing coal power plants with gas power plants reduces climate emissions. However, methane emissions throughout the natural gas supply chain can nullify or even reverse any climate benefits from switching from coal-fired. RGGI's climate projections also ignore the reality that natural gas emits more CO_2 than coal. Declining CO_2 emissions from coal-fired power plants and coal-related methane emissions have been exceeded by increases in CO_2 from natural gas-fired power plants and methane leaks related to the gas used to fuel the power plants. RGGI drives demand for new gas-fired power which provide symbiotic profit opportunities for power companies that are capitalizing on low gas prices and	70% of the auctions to date, and allowance prices have never reached $8 per ton. At the same time, emissions in RGGI have been steadily declining at a pace that exceeds the rate of decline of the RGGI emissions cap. Given the complexity of the electricity markets, it is difficult to discern the precise cause of the RGGI emissions decline in a given year or years. One econometric analysis carried out by economists at Duke University concluded that the RGGI price has indeed been a principal reason for the emissions reductions seen in the RGGI region. This suggests that even at prices between $2-4 RGGI is driving emissions reductions contrary to the commenter's suggestion. Apart from the RGGI price signal, it is clear that adjustments to RGGI's cap from time to time have locked in the emissions reductions that have been realized in the RGGI electricity sector. The commenter suggests the RGGI cost-containment reserve (CCR) has a negative impact on emissions reductions. The CCR threshold is currently set at $10, meaning that allowance prices would have to reach $10 a ton in a given auction for the CCR to be triggered. The auction clearing price for the June 2018 RGGI allowance auction was approximately $4—far below the CCR threshold. As mentioned above, RGGI allowance prices have never exceeded $8 per ton.

	fracking companies that hope the new plants will soak up supplies and ultimately raise prices enough to encourage more drilling. The Department of Energy reported that more than 420 new gas-fired power plants were proposed for construction between 2017-21. The demand for gas-fired electricity generation increases the demand for fracking and natural gas infrastructure, which further expands methane emissions.	Low allowance prices mean lower overall program costs before taking into account the mitigating impact of allocated allowances to consumer benefit. RGGI has locked in meaningful emissions reductions on the order of 45-50% since 2009, while simultaneously keeping allowance prices low. In essence, the RGGI program has achieved its program goal: controlling carbon pollution in a cost-effective and efficient manner. As discussed elsewhere, CO_2 is a global and national problem. RGGI stands for the proposition that a group of states can have a positive impact on emissions without driving emissions allowances up over $8 to date. This effectively balances the need to reduce emissions with the need to keep program costs at a reasonable level. Detailed discussion of how the consignment auction and market mechanisms operate, as well as the benefits of this approach, is available at comments 108 and 136. Executive Directive 11 directs DEQ to "1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that: a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of

		market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits." (Emphasis added.) In other words, the proposed regulation under consideration is designed to meet the Governor's mandate to control CO_2 via participation in an emissions trading program. This emissions trading program is RGGI and, as the commenter states, RGGI does not address methane. DEQ agrees that the control of methane emissions is important; however, this specific regulatory action is not the means by which that will be accomplished. Note that methane is controlled elsewhere in the board's regulations as appropriate, and other measures may be adopted at a different time and in compliance with federal Clean Air Act and state law. As discussed elsewhere, emissions trading programs are authorized under the federal Clean Air Act and are a proven means of reducing air pollution (see, for example, comment 37). Joining RGGI will impose additional controls on each source of pollution beyond technology-based emissions controls imposed by federal and state permitting programs. Note that RGGI specifically

		addresses CO_2, not methane. More information on benefits realized by RGGI is discussed elsewhere; see, for example, comments 61 and 108.
81. BREDL et al.	Because biomass is typically considered renewable under state renewable standards, RGGI does not count CO_2 emissions from biomass processing and combustion. This underestimates the amount of carbon released from this energy source by a significant amount. There is a growing consensus that biomass cannot be considered carbon neutral. Processing, transporting and burning wood at biomass plants all produce GHG emissions, which can be greater than those from coal. Carbon sequestration from the growth of woody material takes decades to occur and is counteracted by the rapid clearcutting of forests to fuel wood-fired power plants. If biomass CO_2 emissions were counted in RGGI states, total RGGI CO_2 emissions could be on average 31% higher than what is currently projected over the next 10 years. This would also undercount the CO_2 emissions from Virginia's rapidly growing biomass industry. From 2011-16, electricity generation from biomass more than doubled in the state. In 2016, 2.60% of Virginia's power came from biomass, nearly 50 times Virginia's energy generation from wind, solar and geothermal energy combined. By not counting these emissions, RGGI would promote the growth of biomass, increase harmful pollution, and suppress the expansion of genuine renewables like solar.	As discussed elsewhere, the focus of this regulation is the control of CO_2 from fossil fuel-fired generators; see the response to comment 67 for additional information.
82. BREDL et al.	RGGI proponents argue that emissions have fallen under RGGI. While CO_2 emissions have declined during the time that RGGI has been in place, there is no indication that RGGI itself has driven these reductions. Those reductions were more likely attributable to the Great Recession than to the program, since RGGI went into effect in 2009 as the economic activity declined steeply. Emissions were already declining before RGGI went into effect; emissions fell faster before RGGI was implemented. Much of the alleged effectiveness of RGGI is attributable to a massive countrywide shift away from coal and oil to natural gas that was already underway when RGGI took effect in 2009. Overall, from 2005-15, coal and oil use decreased from 32% to 9% of electricity production in RGGI states, while natural gas--which has become significantly cheaper because of the risky fracking boom--increased from 25% to 42%. RGGI effectively promotes the expansion of fracking for natural gas at the expense of renewables. From 2009-16, RGGI states have added 4 times more gas-fired electricity generation than wind and solar generation. The percentage of electricity from natural gas-fired	As noted in the response to comment 80, it is difficult to determine the precise factors that lead to a specific result in complex electricity markets. One study carried out by economists at Duke University concluded the RGGI program was in fact a significant factor on the emissions reductions realized in the RGGI region. Other factors, such as low natural gas prices, also played a role. Without a doubt, the RGGI program has effectively locked in emissions reductions of approximately 45-50% since the program began through cap adjustments. Thus, RGGI has been very

	power plants rose by 11.2% from 2009-16 but only rose 2.4% from wind and solar. Natural gas-fired power plants have relied on fracking which benefits power companies but imperils communities. Oil and gas operations have become the second greatest global source of the methane. RGGI further encourages the shift to fracked gas because CO_2 is the chief GHG pollutant emitted from coal-burning power plants. If a power company shifted its energy mix from coal to natural gas, it would accumulate RGGI allowances. While shifting to natural gas results in much lower CO_2 emissions at the power plant, the increased reliance on natural gas significantly amplifies methane emissions. RGGI's failure to consider or cap methane as a GHG allows RGGI states to overestimate climate benefits. The GHG footprint of natural gas is worse than coal and oil because methane traps more heat in the atmosphere. Utilities that switch from coal to gas reduce CO_2 smokestack emissions but could be increasing CO_2 equivalent GHG emissions from methane leaks.	effective in realizing emissions reductions from power plants in the RGGI states. RGGI is a flexible, market-based program that imposes an allowance cost on burning fossil fuels, including natural gas. It therefore tends to discourage electricity generation from natural gas relative to lower carbon sources of electricity such as wind and solar that have no allowance cost. It is wrong to suggest that RGGI promotes natural gas use over renewables. Also note that not all of the energy shift under RGGI has been to natural gas; shifts to renewable energy and energy efficiency are occurring and on the increase in RGGI and Virginia. For example, implementation of the Grid Transformation and Security Act of 2018 will encourage renewables. The set-aside will also encourage the development of renewable and efficiency projects. See the response to comment 51 for further discussion.
83. BREDL et al.	Cap-and-trade programs have the potential to form pollution hotspots and harm vulnerable communities. These populations already face higher pollution exposures because of the disproportionate location of toxic facilities in their neighborhoods. Market-based environmental policies can exacerbate hotspots that remain outside the scope of trading schemes, and they worsen pre-existing health and socioeconomic disparities. RGGI supporters point to the program's ability to raise revenue for renewable energy and energy efficiency initiatives, as well as reduce energy bills for low-income households. However, many states have used this pollution payment scheme to balance state budgets. While governments need revenue, funding from pollution means that governments will be less inclined to eliminate carbon from industry as they become	DEQ is committed to addressing the environmental and health impacts of power plants in all communities, including those communities that have historically borne a disproportionate burden from local air pollution sources. The goal of the program is to reduce carbon emissions from power plants using a tool that has proved effective at reducing air pollution at the lowest possible cost. The

	dependent on the revenue. RGGI proponents assert that the program will save households millions of dollars in electricity rates. This has not been the case. RGGI states' residential consumers have seen their bills go up $1.1 billion since the program was implemented. At the same time, industrial users have seen a $1.9 billion decrease in their electricity bills.	emissions cap is designed to ensure that carbon emissions are reduced from a baseline, meaning that overall the environmental situation is improved from the baseline. Based on the modeling carried out for the proposal, not only would the program reduce carbon emissions, but it will also produce co-benefits in the form of reductions in other harmful pollutants that contribute to low-level ozone and particulate pollution. This is good for the health of Virginians. The commenters are concerned that because the program does not require emissions reductions at specific plants it may not reduce emissions at plants in specific neighborhoods. Individual power plants are subject to facility permits that hold those plants to specific emissions limits designed to protect public health. As discussed in comments 48 and 136, cap-and-trade programs are effective pollution control programs that reduce emissions beyond permitting controls. It is important to note that Virginia is a regulated state in which costs are carefully monitored and managed by the SCC. The program is not raising revenue; the consignment approach ensures that benefits return to the ratepayers, and no funds of any kind will be available for uses other than emissions reductions. The most recent economic analysis found, that from 2015-17, RGGI lowered

		CO_2 emissions while benefiting local and regional economies.
84. Birchwood Power Partners, L.P.	Birchwood Power operates a 240 MW coal-fired cogeneration facility in King George County. Birchwood is equipped with state-of-the-art pollution controls, including low NO_X burners, over-fired air, and selective catalytic reduction to reduce NO_X; use of high quality, low sulfur bituminous coal and a flue gas desulfurization system with a dry lime scrubber to control SO_2; and a high efficiency fabric filter baghouse to control particulate matter. Birchwood provides the advantages of fuel diversification, high energy efficiency, and low emissions, and is located in relatively close proximity to load. This combination makes Birchwood an important tool for balancing grid reliability and environmental protection. Birchwood is one of the few remaining coal-fired power plants in Virginia. In 2005, coal-fired power accounted for approximately 34.6 GWh or about 46% of in-state electricity generation. By 2012, coal-fired generation in Virginia was reduced to 13.6 GWh, about 20% of in-state generation. During the same period, generation from natural gas-fired combined cycle plants increased from 7.3 GWh, 10% of in-state generation, to approximately 23 GWh, 35% of in-state power generation. Further retirements of coal plants and construction of new gas plants are underway. The 2014 Virginia Energy Plan lists Birchwood as a coal-fired plant with projected long-term operations, and it is the only such plant that operates as an independent power producer (IPP). Coal-fired generation is important for maintaining fuel diversity and reliability. Birchwood is dispatched during extreme weather events and peak power demand periods. During Polar Vortex events in 2014 and 2015, natural gas that might have been available for power generation was consumed by residential and commercial customers for heating or, if available, became very costly. The Birchwood plant, with an on-site fuel stockpile, was dispatched at a high capacity factor and was 100% available for dispatch. Birchwood is particularly important to maintaining reliability as it is located close to the Washington D.C. and northern Virginia area and can provide fuel diversity in the face of gas shortages or price spikes. Birchwood's sale of energy is currently contracted to a third-party and is unable to pass the costs of the proposed regulation through to the market. Although Birchwood will be able to include these costs in its price of energy after its contract expires, the economics of coal-fired power plants have been severely impacted by the glut of natural gas, which has reduced energy margins and dispatch of the facilities. The regulation will	The commenter's concerns are appreciated. DEQ is assisting affected sources in managing compliance costs by issuing allowances. The amount of compliance cost covered by the allowances will depend on business decisions made by any individual facility.

	put further pressure on the viability of these critical assets. Birchwood urges DEQ to adopt an approach that preserves a diversified fleet of power plants using different fuels. Diversification of the types of electricity generation sources will help maintain grid reliability during situations where there are natural gas curtailments, periods when renewable energy is limited or not available, and other events impacting individual base load units in Virginia. Birchwood's allocation will be based upon the average generation of the years 2016, 2017, and 2018. During this period, Birchwood's dispatch was at a historical low that represents only approximately 25% of its potential generation, due to the low price of natural gas. As an IPP, Birchwood would be severely disadvantaged based upon the proposed allocations of emission allowances. Accordingly, selection of a different period would more accurately represent dispatch of Birchwood.	
85. Blue Ridge Power Agency (BRPA)	The commenting members (Towns of Bedford and Richlands; Cities of Danville, Martinsville, Radford, Salem; Virginia Polytechnic Institute and State University; Central Virginia Electric Cooperative) are concerned that the board may lack statutory authority to participate in RGGI. Legislatures in most RGGI states have passed authorizing legislation. These legislatures have determined that because RGGI is a reflection of state policies and will require citizens to bear a cost to achieve those policies, those elected by the citizens of those states should make the decision as to whether joining RGGI is justified. Virginia, on the other hand, is acting without the benefit of legislative direction. Governor McAuliffe directed the board to implement RGGI. Without any support other than saying that it is "well settled," Attorney General Mark Herring determined that GHGs fall within the definition of air pollution under Virginia law. To avoid the uncertainty of protracted litigation and to ensure support for the program, the board should defer action until the General Assembly approves participation and authorizes DEQ to administer carbon-reduction programs.	As discussed in the response to comment 76, it is necessary and appropriate for the board to promulgate state-specific regulations controlling carbon pollution. See also comments 139 and 159 for further discussion.
86. BRPA	The rule would not require generators to purchase emissions allowances from the state in an auction, thus avoiding a requirement that all revenue-raising measures must be approved by the General Assembly. Instead, generators would be freely allocated allowances, which they consign to the RGGI auction. Allowances purchased at the RGGI auction would no longer be conditional, i.e., generators would surrender these allowances to DEQ in order to cover their actual annual CO_2 emissions. For each conditional allowance consigned to auction, the generator would receive the clearing price of the auction. This process allows generators to consign all of their	To date all emissions trading programs implemented by Virginia have allocated emissions allowances to the compliance entities. This is consistent with the approach recommended repeatedly by EPA in the various federal model rules offered for implementation by states beginning with

	conditional allowances but only purchase what they actually need. Unneeded allowances would be sold, with the proceeds collected by the generator. The program does not address the treatment of these windfall proceeds and, importantly, contains no provision specifying how such windfalls would be returned to consumers. The impact of the program on monthly customer bills is not reliable, and the impacts are likely to be considerably higher. The regulation preamble suggests that the average monthly bill impact for residential, commercial, and industrial consumers through the year 2031 will be nominal--never more than 1.1%. These estimates are taken from an impact analysis prepared by a consultant that assumes that "95% of revenues that accrue to utilities from the sale of carbon allowances or credits are returned to ratepayers." No factual basis exists upon which to base an assumption that 95% of the revenues accrued would be returned to customers. As DEQ recognizes, the "revenue received by CO_2 Budget Sources owned by regulated electric utilities flow to rate payers pursuant to SCC) requirements." However, there is no legislative or other mandate to require the SCC to impose such a requirement on regulated utilities. The outcome of any proceeding at the SCC contemplating a proposal to direct the regulated utilities to return RGGI windfalls to customers is uncertain. Relying on the presumed outcome of an action that may or may not be taken by a different regulatory agency as the basis for cost estimates is speculative. The cost estimates developed by The Analysis Group fail to take into account that a significant share of the covered generators are not subject to SCC jurisdiction. Approximately one-third of the energy produced in Virginia in 2015 was generated by facilities owned by IPPs., which are not regulated by the SCC and would not be subject to any regulation that may be adopted later by the SCC. These facilities sell power into the regulated wholesale markets, and those sales are subject to the exclusive jurisdiction of FERC. The consultant's study assumes that "revenues from allowances to independent power producers [would be treated] in the same way as those allocated to utilities (i.e., revenues returned to ratepayers)"; however, no state mechanism exists to assure that the benefits of allocations to IPPs actually accrue to ratepayers. The program would allow these facilities to make windfall profits off of their allocated share of RGGI allowances, and permit those profits to lay beyond the jurisdictional reach of the state's rate regulator. Surely this approach is contrary to the program's intent. The board should explain why customer bill impacts should not be adjusted to remove revenues from allowances to unregulated entities, or	the NO_X Budget Program in the late 1990s. This program will similarly allocate allowances to compliance entities. The program does two things that address the concerns voiced by the commenter. First, compliance entities will consign their allocated allowances to auction, where the allowances will be sold. Unlike previous programs, this means that the value of the allowances will be transparently known to all observers of the auction. This, in turn, means that the utility commission will have a clear valuation of the allowances to use in carrying out their responsibilities. Second, the allocations are to be made on an updating, output basis. This means that the allocation will tend to reflect the facts in the field: the plants that run more will get more allowances and the plants that run less will get less. This should greatly reduce the chances of an overallocation to individual plants. The commenter notes that independent power producers are not subject to rate regulation by the commission. To the extent the power generated by independent power producers is purchased by regulated utilities, however, the costs of that power are indeed the subject of regulation. This would include any embedded allowance costs. The commission, therefore, may

	explain what regulatory mechanisms would assure those revenues are returned to customers. The RGGI model rule leaves how to allocate allowances to states. Under the proposal, allowances will be allocated to units based on the average of the 3 amounts of the unit's total net-electric output during the 3 most recent years for which data are available prior to the start of the control period. All covered units in Virginia, regardless of whether they are regulated by the SCC, will receive an allocation of allowances based on past operation and the right to potentially convert those allowances into profits. Note that no other state has chosen to allocate 95% of allowances to generators. The allocation of conditional allowances to generators based on historical usage is arbitrary, and likely to overcompensate generators and produce excess allowances because energy production at many of the covered units will continue to decline as zero-carbon resources compete with high-carbon emitters. These excess revenues will be sold at auction or banked by the generators, but those entities that have made investments in energy efficiency and carbon-reducing technologies are provided nothing. Further, the board has stated that the SCC will need to act to require that regulated utilities return auction revenues to customers. But until those rules are finalized there is no guarantee whether or how that will be done and there is a risk that the funds will become windfall profits to the recipients of allowances. It is also unclear as to how Virginia customers will receive any benefit from the profits earned by unregulated IPPs. An alternative to the allocation of allowances to units is to directly allocate allowances to load-serving entities (LSEs) in proportion to their customers' energy consumption. The value could be passed on to those customers by way of offsetting reduction to their bills, or the benefits of programs to invest in local alternative energy projects in their service territories. This approach would not foreclose the statewide set-asides of allowances to support energy efficiency programs. The commenting members therefore strongly urge the board to withdraw the regulation for the purpose of considering whether allocation of consignment allowances should be redirected from generating units to LSEs. The preamble does not explain how the program would impact the cost of wholesale power sold to Virginia entities, which it would assuredly do for BRPA's members. These impacts take effect at the wholesale markets regulated by FERC. With respect to power purchase contracts that include a formulaic type of cost-of-service rates, the cost incurred by the owners of covered generators of procuring RGGI allowances are	have some influence over whether the costs of allowances are in fact passed on to consumers when the compliance entities have received the allocations at no cost to them. In any event, the program will make such regulatory decisions much easier than previous emissions trading programs where allowance allocations were made without the benefit of a consignment auction or without updating. See, for example, comment 136. According to the bill impact analysis conducted on DEQ's behalf, costs are expected to be minimal.

	likely to be passed through in those cost-based rates. However, it is not clear whether revenues from the auction for consigned allowances would be credited through the formula rate process and returned to our members. This is to be decided by FERC, and could leave members and consumers with the obligation to bear the costs of RGGI without any offsetting revenues. Energy prices could increase as the cost of RGGI allowances are incorporated into the energy offers that are submitted into the PJM energy markets. Energy prices in the regional markets are determined by the offer of last-dispatched and highest-price resource, and because the auction is a single-price auction the generator's cost of RGGI allowances could have region-wide price impacts. Over time, the program would ratchet up the RGGI allowance price and ratchet down available quantity, so the cost of RGGI will become more apparent in wholesale market prices. BRPA members will see a more significant impact of RGGI on wholesale power costs. Participation in RGGI has the potential to affect congestion paid by our members. Wherever power is generated, whether in Virginia or another state, it must be moved financially from that location into the Blue Ridge. Regardless of the contract price, if the price of power at the point of generation in another state is low and the price of power in the Blue Ridge area is high, the purchaser must pay for the difference, and those costs can be substantial. We ask the board to reconsider the allocation of conditional allowances to generators. The Regulatory Advisory Panel was clear: cost to customers should be a primary consideration. In fact, the panel could not come to consensus on whether LSEs or generators should receive the auction credits. Assigning allowances to LSEs is the most direct way to assure that the benefits of RGGI accrue to intended beneficiaries--retail consumers in Virginia.	
87. Calpine	Calpine supports cap-and-trade programs that place a clear price on carbon emissions in a way that allows such a price to be reflected in wholesale power prices and that are designed to minimize market distortions, including broad coverage of new and existing power generation facilities that emit GHGs; effective and equitable methods for distributing emission allowances; minimization of leakage issues that result from differing requirements from one state to the next; and setting allowance budget caps at a level that will result in meaningful carbon reductions by incentivizing environmentally efficient dispatch of power generation facilities. For these reasons, Calpine supports the proposal, including allowing Virginia sources to use allowances that either originated in Virginia or any other RGGI state. Linkage with RGGI will allow for a broader, more flexible emissions market, helping to improve	Support for the proposal is appreciated, as is the commenter's discussion of the benefits of RGGI and its market mechanisms. As discussed in the response to comment 37, a cap of 28 million tons was selected.

	market competitiveness and trading efficiency while lowering carbon abatement costs for affected generators. Because Virginia's linkage with RGGI will significantly expand the size of the RGGI market, it is important to recognize the potential impact of the level of Virginia's base budget on the RGGI program and on allowance prices. A budget that is not based on reasonable assumptions regarding the generation mix in light of a cap-and-trade program in Virginia may result in significantly higher or lower compliance costs for the overall program. In RGGI's most recent auction, CO_2 allowances sold at a relatively weak clearing price of $3.79. This suggests that a too-high base budget could further weaken the carbon price signal. At this price, the societal value of the RGGI program is largely limited to income it generates for the participating states; it is too low to impact power system dispatch to any meaningful degree. Thus, Calpine recommends that Virginia set its initial base budget to no more than 34 million tons of CO_2. The proposed budgets account for recent trends in Virginia's electric generation sector, including planned retirements of fossil fuel generators and opportunities for clean energy and energy efficiency. The opportunity to trade with other RGGI states, and the inclusion of the CCR, help ensure that a base budget no higher than Virginia's proposed levels is reasonable and will ensure sufficient overall market liquidity. Recognizing the historically low allowance prices in the RGGI region, Calpine supports the proposal to include the ECR.	
88. Covanta	We fully support efforts to reduce GHG emissions through a market-based mechanism. We are proud to be part of efforts already underway to reduce GHG emissions in Virginia. Covanta operates EfW facilities in Fairfax County and Alexandria. These facilities are recognized internationally as a source of GHG emissions mitigation and low carbon energy generation. EPA has determined that EfW facilities reduce lifecycle GHG emissions by one ton of CO_2 equivalents (CO_2e) for every ton of MSW diverted from a landfill and processed. Based on Virginia data, every ton of MSW diverted to EfWs reduces GHG emissions by roughly 0.7 tons CO_2e. Covanta's Alexandria and Fairfax facilities annually reduce GHG emissions by over 900,000 tons of CO_2e a year relative to landfilling. Capping emissions through a trading-ready approach will incentivize the use of low-carbon energy sources that promote economic development and job creation. To achieve the most cost-effective program, we support a full portfolio of clean energy technologies and services, including wind, solar, energy efficiency, and EfW. We encourage DEQ and DMME to leverage the set-aside mechanism to further support renewable generation, both for existing facilities	Support for the proposal is appreciated. DEQ agrees that EfW facilities play an important role in the reduction of carbon pollution.

	that face ongoing operating costs as well as new capacity, inclusive of both greenfield development and additional generation achieved at existing facilities. We also support the proposal to allocate allowances on the basis of regularly updated electricity output, as opposed to historical emissions. This approach provides the greatest alignment between the carbon intensity of electrical generation and the market-based policy signal.	
89. Center for Resource Solutions (CRS)	The RGGI Model Rule includes a voluntary renewable energy market set-aside provision. Virginia would be able to draw on the experiences of 8 other RGGI states that have successfully implemented this provision. We strongly recommend that Virginia incorporate this or a similar provision in order to maintain and grow the environmental and economic benefits of voluntary, private investment in renewable energy. Under the rule, GHG reductions at regulated electricity generating facilities due to renewable energy generation will be automatically counted and reported by those facilities toward compliance, and since the rule determines and fixes the level of emissions from the sector, there is no net change to emissions at regulated sources due to renewable generation. In this scenario, voluntary renewable energy can have no impact on statewide or regional GHG emissions beyond what is already required; furthermore, it subsidizes compliance for regulated entities. As voluntary renewable energy reduces emissions counted toward compliance, voluntary purchases help reduce the cost of compliance, making it cheaper and easier for regulated emitting facilities to comply. This presents a different value proposition for voluntary and corporate buyers and investors in comparison to circumstances prior to implementation of the rule. Voluntary renewable energy is not used to meet governmental targets or mandates--it stands apart from and builds on compliance efforts. This separation enables the voluntary market to make an incremental difference or "regulatory surplus." Voluntary purchasers of renewable energy tend to value this incremental impact highly. Renewable energy generation that is counted toward regulatory compliance cannot be considered surplus to regulation. Regulatory surplus with respect to GHG regulation may be important for voluntary renewable energy demand. Since many of the companies and individuals purchasing in the voluntary market do so a commitment to address GHG, an effect on emissions beyond what is required by law may be a non-financial benefit. Where renewable energy sold into the market does not have an effect beyond compliance and only helps regulated entities comply, this changes the effectiveness of voluntary renewable energy as a climate change solution for companies and individuals.	As discussed in the response to comment 51, DEQ recognizes the value of a voluntary renewable energy market as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement that set-aside. DMME may, at the appropriate time and in accordance with its regulations and policies select a voluntary renewable energy market set-aside.

	As such, voluntary demand for renewable energy may decline if these benefits do not remain intact. Virginia's program can protect voluntary renewable energy benefits and demand by incorporating a provision that sets aside and periodically retires allowances for voluntary renewable energy, effectively lowering the emissions cap on its behalf. This mechanism would counteract the automatic counting of emissions reductions associated with voluntary renewable energy and recognize those emissions reductions as incremental to what would otherwise be achieved through GHG regulations. This helps preserve voluntary demand and private investment in renewable energy as drivers of emissions reductions, which can lower the cost of and reduce the need for GHG regulations. The RGGI Model Rule contains provisions for the number of tons that would be allocated to the voluntary renewable energy market set-aside account in a specific control period, including a sample formula with which the state could calculate the quantity of set-aside allowances that would be required. Regulatory surplus is critical to sustaining clear voluntary claims and has been helpful in the RGGI region in sustaining voluntary investment in renewable energy beyond what is required. A voluntary renewable set-aside preserves regulatory surplus for voluntary renewable energy by lowering the emissions cap and recognizing those emissions reductions as incremental to what would otherwise be achieved due to the cap. A set-aside can motivate private capital to produce voluntary renewable energy generation and emissions reductions in excess of state mandates. Alternatively, where voluntary demand for renewable energy is limited, so is the development of renewable energy and associated emissions reductions. By not including a set-aside for voluntary renewable energy in the regulation, Virginia may potentially leave privately-funded emissions reductions on the table, which it will later have to regulate to achieve. Green-e sets the standard for the voluntary market . To maintain the impact of the voluntary market and meet consumer expectations, Green-e requires a set-aside mechanism or allowance procurement and retirement for certified sales in regions covered by cap-and-trade regulation. Due to lack of a set-aside, Green-e would not be able to certify voluntary sales of renewable energy from within RGGI or Virginia to customers in Virginia, unless the customer pays the additional price to independently purchase and retire an allowance. Since customers are unlikely to pay this additional cost, we anticipate that there would be no Green-e market for Virginia renewable energy generation, or for RGGI	

	renewable energy generation that is sold into Virginia. Voluntary buyers in Virginia will have to get their certified renewable energy from outside of the RGGI region. In 2016, Green-e certified over 728,000 MWh in sales to over 30,000 retail customers located in Virginia. This shows strong demand for voluntary renewable energy in the state.	
90. Dominion Energy	We support a program that would allow for emissions trading and be trading-ready. The program should reduce carbon emissions not only in Virginia, but regionally. The program should encourage the growth of cleaner-emitting generation commensurate with the Grid Transformation and Security Act of 2018, which finds 5,500 MW of new solar and wind in Virginia in the public interest, as opposed to encouraging the increase in the dispatch of higher emitting generation in neighboring states. It must recognize the benefit of reducing purchased power from out of state and its impact on the environment, the Virginia economy and Virginia jobs. The program must establish a representative baseline that accounts for the emissions serving Virginia customer energy needs from which to determine and measure emissions reduction goals. This should account for emissions from in state generation sources as well as emissions from purchased power. The plan should evaluate and set emission goals and realistic implementation timelines that will provide needed time for the ramp-up of new renewables, energy efficiency programs, and infrastructure improvements in order to maintain the state's fuel diversity and goal to become more energy independent. The program should recognize the role of extending the operation of Virginia's existing fleet of carbon-free nuclear generation and the role of natural gas as the lowest cost, cleanest and most reliable form of dispatchable generation to complement the integration of renewables to the grid. It should also account for electrification of other sectors of the economy, such as transportation, and must not hinder the growth of electric vehicles. The program should be flexible, with multi-year emission averaging and other measures so that reductions can be achieved in the most cost-effective manner. The program should address electric system reliability and rate impacts.	Support for the proposal is appreciated. Specific issues identified by the commenter are discussed in further detail below.
91. Dominion Energy	Any program setting carbon emission targets for electric generating units must accommodate for the dynamics of power generated outside of and imported into Virginia. The baseline and targets must account for the fact that Virginia is a net importer of energy from more carbon-intensive out-of-state resources. The program must also incentivize the expansion of lower-emitting cleaner generation in the state, and reduce imports of electricity. Encouraging the expansion of natural gas-fired combined cycle and renewable energy resources will grow the economy and lower emissions by decreasing reliance on imported carbon-intensive power. Setting a	In theory, emissions "leakage" occurs when an emissions cap causes generation to shift from the area under an emissions cap to an area outside the cap, and that shift leads to increase in emissions. A number of factors make emissions leakage unlikely in the case of the trading program in Virginia.

	stringent cap on already cleaner generation in Virginia absent a similar level of reductions from neighboring states or a way to address leakage would increase the cost burden to Virginia generators. This would encourage lower cost electricity imports that are more carbon-intensive and not subject to a carbon cost adder, and result in limiting the dispatch natural gas combined cycle facilities in Virginia. In the PJM Interconnect, units are dispatched based on "replacement cost" of the variable components required to run the unit. The variable components include fuel and emission allowances, such as RGGI allowances. The replacement cost changes based on the market value of the type of fuel used in a unit and the market value of the allowance. Dominion does not choose when to operate its units, units are called upon by PJM. If Dominion units are above the target price for the day, other units, generally less controlled and more carbon intensive, will be called upon to meet load demand. Due to a carbon cost adder to the unit bid price when Virginia units bid into the electric market that other PJM resources would not have to account for, Virginia generators will be less competitive, resulting in increased imports. Coupled with the retirement or curtailment of fossil fuel-fired resources, this raises reliability concerns. These concerns are borne out by modeling analyses. In support of the company's 2018 IRP, ICF provided Dominion with forecasts for cases where Virginia joins/does not join RGGI. Virginia linking to RGGI does not reduce emissions regionally. The modeling results indicate that Virginia entering RGGI in 2020 does not result in overall carbon emission reductions in the EI or PJM regions by 2030. Emissions in the entire EI in 2030 are about 10 million tons higher than emissions in 2020 and about 3 million tons higher in the PJM region during the same period. The analysis shows that emissions reductions achieved in the RGGI region are offset by emissions increases in the non-RGGI portions of the EI region. Cumulatively, over 2020-30, emissions in the portion of the EI subject to RGGI are reduced by about 75 million tons, but increase by almost 90 million tons in the non-RGGI portion of the EI In the RGGI region, emission decreases over the period 2020-30 with Virginia linked to RGGI are driven by emission reductions in Virginia emissions in the non-Virginia portion of RGGI actually increase. The modeling results also show significant increases in net energy imports in Virginia, increasing from about 28% under the case with no carbon regulations in Virginia to 48% for the case with Virginia linked to RGGI. At the same time, the weighted average capacity factor for NGCC facilities in Virginia is projected to decrease by almost 50% between 2020 and 2030 under the RGGI	The electricity markets are in a period of significant change. Retirements of older plants and construction of new plants in new locations means changes in where power is generated. In addition, plants closer to the well heads tend to enjoy lower fuel costs—the primary operating cost for natural gas power plants. The cost of transmission, in contrast, favors plants that are closer to the load the plant serves. Thus, while differences in environmental costs have the potential to change the relative costs of plants in Virginia compared to plants outside Virginia, shifts in generation are determined by a whole host of other factors that are more significant than the low RGGI allowance price. Second, the owners of generation in Virginia are unlikely to face any competitive disadvantage relative to plants outside the state because the allowances are to be allocated to compliance entities under the program, and the amount of the allocations are to be determined on an updating output basis. To the extent a generator must use an allowance to generate power and also receives an allowance at no cost, the generator does not have an increased operating cost relative to plants outside Virginia. If there is no competitive disadvantage, there can be no shift in generation caused by the program.

	case. DEQ modeling of Virginia linking with RGGI showed similar increases in power imports under both policy scenarios evaluated relative to the case with no carbon regulations in Virginia. DEQ has proposed an updating output-based allowance allocation approach that it believes will incentivize utilization of NGCC resources as a means to counter leakage. However, while an updating output-based allocation approach may be more favorable to NGCC units relative to coal-fired units, it does not address leakage. Natural gas-fired units in Virginia will still be subject to a CO_2 cost adder that units outside of the region will not be subject to. The effect of RGGI-equivalent reduction requirements in Virginia is likely to limit the dispatch of highly efficient and lower emitting NGCC facilities in Virginia and encourage the dispatch of higher emitting resources and increased emissions in neighboring states outside of the RGGI region. Average carbon intensity in 2030 of electricity serving Virginia with the state not joining RGGI is projected to be 742 lb/MWh in 2030; the carbon intensity increases to 784 lb/MWh if Virginia joins RGGI. This is a 5.7% increase in carbon intensity of the electricity used by Virginia customers largely due to increased electricity imports into Virginia, which have a higher carbon intensity than in-state generation.	Third, vertically integrated utilities have the option of self-scheduling their generation in the competitive wholesale electricity markets. This means that even where generators outside the state have a lower operating cost that is the result of the program's allowance cost, utilities may choose to run anyway because it makes economic sense to do so. Utilities, therefore, have a tool to prevent the generation shifts that might otherwise constitute leakage. Fourth, updating output-based allocation is expected to encourage generation in the state, rather than discourage it. Because power plants receive allowances only when they operate, the program is set up to discourage generation shifts by rewarding in-state generation. According to an August 2017 study conducted by researchers at the Regional Economic Studies Institute and Resources for the Future, updating, output-based allocation can be an effective tool to counter incentives to shift generation to areas not covered by an emissions cap. Fifth, if a shift in generation does in fact occur there is some question whether the shift is likely to lead to an increase in emissions. Natural gas has become the dominant fuel in PJM and typically fuels the marginal unit. To the extent

		a shift occurs between a natural gas plant in Virginia to a natural gas plant outside Virginia, there may be no increase in emissions that occurs as a result of the shift, especially to the extent adjustments to the emissions cap are made over time to address any excess allocations under the trading program. For all of these reasons, DEQ believes that emissions leakage is unlikely to occur under the program (see responses to comments 108, 136 and 144). Also note that the implementation of the DMME set-aside will also encourage the reduction of in-state demand, thereby reducing carbon pollution and further preventing leakage. To the extent the possibility of leakage may theoretically exist, current evidence suggest that it has not happened under RGGI. RGGI issued the "CO_2 Emissions from Electric Generation and Imports in the Regional Greenhouse Gas Initiative: 2015 Monitoring Report." This report, the seventh in a series of annual monitoring reports, summarizes data from 2005-15 for electricity generation, net electricity imports, and related CO_2 emissions for the participating states. These monitoring reports were called for in the 2005 RGGI MOU in response to concerns about the potential for the RGGI trading program to cause emissions leakage. The

		observed trends in electricity demand, generation, and net imports show there has been a small change in CO_2 emissions from total non-RGGI electric generation serving load in the RGGI region during 2013-15 when compared to the base period, and the CO_2 emissions from this category for 2015 show there has been virtually no change when compared to the base period. In other words, the carbon intensity of additional generation is reduced, and emissions leakage has not actually occurred. Linking to RGGI will make Virginia a participant in RGGI's scheduled program reviews, and those program reviews can address any leakage problems should they arise with the program in the future. RGGI participating states perform comprehensive, periodic program reviews to consider program successes, impacts, and design elements. Stakeholder meetings are held throughout the program review process in order to encourage stakeholder engagement and the submission of comments from interested parties. As part of this process, DEQ will evaluate how the program is working from a Virginia standpoint as well as in the context of the other RGGI states. In addition to regular RGGI program reviews, the regulation will also be subject to state periodic

		review as required by § 2.2-4017 of the Virginia Administrative Process Act. The periodic review procedure includes a review by the Attorney General to ensure statutory authority for the regulation, and a determination by the Governor whether the regulation is necessary for the protection of public health, safety and welfare, and is clearly written and easily understandable. Regulations under periodic review are subject to public comment; this would be another venue to identify concerns about program implementation.
92. Dominion Energy	Based on ICF modeling, linking to RGGI is projected to cost Virginia customers about $530 million over 2020-30, significantly less than actually joining RGGI. The modeling indicates that Virginia linking to RGGI will lower allowance prices thereby lowering the cost of carbon compliance in other RGGI states, subsidized, in part, by Virginia electricity customers. Should Virginia link to RGGI, customers in RGGI states outside of Virginia will incur $876 million less in cost related to RGGI allowance purchases from 2020-30 than the RGGI states would incur without Virginia joining RGGI. Additional costs related to carbon reductions isolated to the state and stranded investments for forced closures will be borne by customers. With the majority of the PJM region not subject to carbon regulations, the energy market will favor non-Virginia generating units, making Virginia units less competitive. This will advantage licensed competitive service providers (CSPs) that cover load through power purchases from non-Virginia-based resources. Unless these costs are non-bypassable, larger energy customers that have the ability under retail choice to purchase energy from a licensed CSP may find that CSPs can provide more attractive pricing and can avoid the costs related to carbon reductions. To the extent larger customers migrate to CSPs, remaining customers will bear the cost for compliance with the state carbon program.	The commenter is correct that the modeling showed that linking Virginia's program to RGGI did modestly reduce the modeled allowance prices for the program overall. These lower costs are exactly what one might expect when making an emissions trading market bigger. Bigger markets open up greater opportunities for lower cost reductions and lower overall costs for consumers across the entire footprint, including in Virginia. The commenter provides no evidence to support its assumption that the PJM market will favor non-Virginia units over Virginia units in the presence of the program. In general, generating units place bids to supply power to the wholesale market and those bids depend on the generator's costs to generate power. Fuel cost is the biggest component of a bid to supply power, and fuel cost depends on the

		fuel market and a plant's efficiency, not on the program. The program will allocate allowances on the basis of output from a generating unit and allocations will be periodically updated. As a result, the program will provide additional value to a generating unit in Virginia that operates. This will tend to encourage Virginia units to operate, not discourage them compared to units outside the Commonwealth that do not earn this additional value. In addition, to the extent a unit incurs an incremental cost from the program, that cost is expected to be offset in whole or in part by the allowance value received through the allocation and the consignment auction. Essentially, the outcome is an effective program with a modest price tag
93. Dominion Energy	The 33 million ton cap case uses assumptions from Dominion's 2017 IRP; the 34 million ton cap is based on RGGI assumptions. IRPs depict a suggested portfolio expansion and tend to change on an annual basis. While IRPs may provide guidance in setting long-term goals, their purpose is not to establish regulatory requirements. Fundamentals-based models, such as the IPM model, are useful for evaluating the impacts of policy strategies but should not be used to set the program baseline. Rather, an emissions baseline should be established on historic emission levels including allowance for historic variations in emission levels due to year-to-year differences in weather and fuel prices. For example, for the initial RGGI cap determination in 2005, RGGI designers set the 2009 cap about 4% above the average emission levels observed between 2000-02. Historical data have also been used by EPA in establishing baseline levels for various trading programs including CSAPR and the NO_X SIP Call. 2016 emissions for Virginia units that would be covered under the Virginia proposal were about 35.3 million tons. An analysis of statewide emissions from electric generating units in Virginia over the last 20 years shows an average annual emission level of about 35 million	As discussed in the response to comment 37, a base cap of 28 million tons was chosen as the most representative and effective starting point for the program. This number is a reasonable starting point as evidenced by the modeling results, which tend to show reasonable cost impacts from the program using this base cap number. As discussed in numerous comments elsewhere, energy efficiency and renewable energy are increasing in Virginia, and the cap-and-trade program will contribute to this trend.

	tons with ±1 0% CO_2 emission volatility. Average emissions over 2014-16 were about 34.3 million tons. Applying a 10% margin to account for variability would yield a cap of over 37.5 million tons. Applying the same 4% margin used in setting the initial RGGI cap yields a baseline of about 35.7 tons. Accordingly, the 2020 baseline should be between 35.7-37.5 million tons to provide a margin to account for year-to-year fluctuations in weather and fuel price volatility. (This analysis does not include emissions from new generation projects.) The modeling performed for DEQ by ICF projects almost 1100 MW of additional coal-fired capacity retirements by 2020 in the Virginia assumptions case and over 1500 MW of coal capacity retirements by 2020 in the RGGI case. Unit retirements should not be used to set the baseline. Efforts to reduce emissions by way of unit retirements implemented in advance of the baseline date should be applicable toward compliance and not penalized by applying them toward a further reduction to the baseline level. The data record must include the emissions from all units covered under the program, including units at which CO_2 emissions are not measured by continuous emissions monitoring systems. Coupled with the ability to credit reductions that occur prior to 2020, this would be a more fair approach. The 2020 baseline and reduction targets thereafter should not be based on a presumption that energy efficiency potential based on policies in neighboring states can be achieved in Virginia. Dominion continually works to achieve operating efficiencies to obtain more output with fewer emissions. In addition, we offer a number of end-use energy savings programs to our customers. As reported in the 2017 IRP, these programs have already achieved a substantial amount of energy savings; however, some of these programs are due to expire. Implementation of future programs is subject to approval by the SCC, which is not within the company's control. Dominion has filed approximately 36 replacement and new programs for approval by the SCC, and to date about two-thirds of them have been approved. While there remains potential for energy savings from consumer-side energy efficiency programs, this expansion is subject to state law and regulation. The success of these programs is affected by the degree to which customers choose to participate. Regardless of the success of energy efficiency programs, utilities must be prepared to serve their native load. Accordingly, the emissions target should be based on reasonable expectations of achievable energy savings and the compliance timelines must provide adequate time for the development of energy efficiency programs deemed	

	necessary to achieve such objectives. The Virginia cap should not be more stringent than levels that would have been imposed under the CPP. Although the intent of the Governor's directive is to regulate carbon in the absence of federal action, it does not compel the state to establish emission targets equivalent to or below levels that would have been imposed under the CPP, which was approximately 27.8 million tons in 2030. The mass-based carbon emissions target EPA established under the CPP underestimated potential future growth to meet energy demand and was the most costly compliance alternative identified in the 2017 IRP. The limits required under the CPP envisioned a nationwide emissions trading program. Virginia should not impose more stringent emission reduction requirements to address a global environmental issue while the states we compete with economically have no emission reduction goals or requirements. RGGI re-assesses its program every 4 years based on historical performance. Since 2009, RGGI has conducted program reviews in 2012 and 2016-17. Both reviews resulted in a lowering of going-forward CO_2 emission caps for the RGGI region. The next assessment period is scheduled to occur in 2021, which is only one year after Virginia would begin its participation in RGGI. This means that Virginia cap identified through 2030 may be re-negotiated in 2021 with other member RGGI states and may be different than what is currently proposed. Virginia's entrance into RGGI creates just two years (2020 and 2021) of "certain" CO_2 limitations. Based on RGGI's two prior re-assessments, the CO_2 cap will likely be different than what is currently proposed, which increases uncertainty in electric utility planning.	
94. Dominion Energy	We support limiting compliance applicability only to fossil fuel-fired electric generating units greater than or equal to 25 MW. Small combustion turbines and boilers below this threshold should not be subject. This is consistent with many existing federal and state-level EGU-based emission reduction programs including EPA's Acid Rain Program, CSAPR, and MATS, and the RGGI model rule. Consistent with the CPP, we support exempting units that use biomass as their primary fuel. In 2013, Dominion converted 3, 51 MW coal-fired units to 100% biomass. Close proximity to an ample supply of waste wood biomass as well as EPA's carbon-neutral policy for permitting were key economic drivers for these projects. Given Dominion's investment in renewable biomass, it is important that biomass emissions remain exempt. Any departure from EPA's prior treatment of biomass as carbon neutral or action that eliminates the use of this fuel as a creditable compliance option could raise compliance costs.	See the response to comment 67 for a discussion of biomass applicability.

	This compliance exemption should also apply to fossil fuel-fired units that are co-fired with biomass, such as the Virginia City Hybrid Energy Center (VCHEC). Under the proposal, a fossil fuel-fired unit that co-fires with biomass would be obligated to hold allowances for all of its emissions. This is a disincentive for a coal-fired power plant to reduce its carbon emissions. VCHEC burns waste coal and co-fires with biomass. In 2008, the board directed DEQ to incorporate a timetable for biomass utilization in the facility's PSD permit. According to DEQ, the board chose this approach "in order to promote further reductions in sulfur dioxide emissions and show a reduction in carbon emissions. since biomass is considered a biogenic carbon-neutral material." Requiring VCHEC to now hold allowances under a state carbon program for emissions resulting from the burning biomass in compliance with an air permit provision established to address carbon is counterintuitive. Requiring fossil units that co-fire with biomass to hold allowances would also be inconsistent with RGGI which only regulates fossil fuel fired units and provides calculations to subtract CO_2 emissions from biomass from multi-fuel fired units. To regulate biogenic emissions would be a significant departure from the existing RGGI program. It would put Virginia's forest owners and biomass-related renewable energy investments at risk, while creating unnecessary complexity. To the extent that the regulation requires biomass units to hold allowances, the budget must be increased accordingly to assure that the emissions from these facilities are included in the baseline.	
95. Dominion Energy	Dominion supports the consignment auction approach but the proposal does not provide details of the auction process and how revenue will be handled and transferred. The rule mentions that such revenue transfers will be done "in accordance with procedures established by the department." Clarity is needed as to how the Virginia allowances, which are proposed to be allocated annually, will be merged with the RGGI auctions, which are conducted quarterly. Additional legislation is required for the board to designate use of revenue associated with a trading program. Absent such authority, DEQ could not directly conduct an allowance auction or collect revenue from an auction. The consignment auction approach could provide a mechanism for the rule to proceed. Accordingly, to the extent the regulation links to RGGI via auction, we support the consignment approach. Direct auctioning would increase the stringency and cost of the program by forcing generators to purchase allowances they otherwise would have been allocated. EGUs would have to pay twice to reduce emissions: first to reduce emissions from affected EGUs or to develop	DEQ agrees with the commenter that at this time the consignment auction is a cost-effective approach for the trading program. Use of the RGGI auction platform provides an already functioning system with detailed procedures that have proven effective. Details as to how the specifics of the auction will operate will be addressed in auction "instructions" which are developed separately from the regulation. DEQ will take the commenter's concerns into account when those instructions are developed. The consignment auction is designed to be cost neutral while enabling participation

	new low-emitting generation, and second to obtain allowances to cover their remaining emissions. Modeling scenarios performed by ICF with Virginia joining RGGI with the auction proceeds returned to the state projected costs to the customer that are three times higher than costs estimated under the consignment auction approach. We support the proposal to allocate most allowances to affected EGUs using either historic generation (output based) or emissions data. This approach is reasonable, consistent with many of EPA's other emissions trading programs, such as the ARP and the CSAPR, and will help to minimize compliance and customer costs. Allocating allowances directly to affected EGUs who have a clear financial interest in complying with the rule will create a more reliable, predictable, and manageable system. Direct allocations to non-affected entities could increase the stringency of the cap by forcing affected sources to acquire allowances they otherwise would have been allocated, and under the proposed consignment auction approach, would have the opportunity to recover cost through auction revenue returned to the generator. This would increase the cost of compliance for affected EGUs and therefore ratepayers. RGGI's quarterly auctions limit how many allowances a single entity can bid (25% of the initial offering of CO_2 allowances in the auction). If Virginia participates in the RGGI auction program, such a limitation might not make it possible for all the compliance entities in the program to rely strictly on the auction to acquire their necessary allowances and they may be forced to go to the secondary market to get sufficient allowances needed to comply. This bidding limitation has not been an issue to date in RGGI because there has not been a single entity requiring enough allowances to hit the 25% limit. Virginia should advocate that RGGI amend this rule by expanding the size of the bid limitation by anyone entity such that every entity has the possibility of relying on the auction for compliance.	in the RGGI auction and providing for implementation of the CCR, ECR, and auction reserve price. Generally, the purpose of a regulation is to establish the relationship between DEQ and an affected facility; i.e., the department sets requirements that the facility must meet, and the facility does so following the provisions of the regulation.
96. Dominion Energy	An updating frequency of less than 3 years (including annually) should not be considered. A unit that retires should not be required to give back allowances it has already been allocated. The allocation approach should provide a reasonable lag time between unit retirements and the discontinued allocation of allowances to those units, an approach EPA has allowed under trading programs such as CSAPR. The updating allocation methodology will effectively transition retired units out of the allocation cycle without requiring units to give back allowances. With respect to the baseline for determining a unit's pro-rata share of the state total budget, we suggest using the average of the 3 highest years over	A 3-year period was chosen as the most realistic compromise between too much and too little flexibility. It is designed to avoid year-to-year variations that result from external factors that may influence operation and have a serious impact on allocations. At the same time, the 3-year period prevents allocations from

	the previous 5-year period. This approach, which is consistent with other successful programs such as CSAPR, would provide additional flexibility to assure a baseline representative of a unit's normal operations and filter out years when a unit experienced atypical utilization. The rule must provide a mechanism for providing allocations to units that meet the definition of an existing unit but do not have 3 years of historical operational data. In cases where a unit does not have a full year of operational data over the 2016-18 time period, the allocation could be based on an estimate of projected annual operation with a requirement that the source give back any unused allowances for redistribution to existing sources.	being coming static.
97. Dominion Energy	Under the proposal, 5% of the statewide budget would be set aside and allocated to DMME. These allowances would be consigned for auction by the holder of a public contract with DMME to assist the department in the abatement and control of air pollution. However, the proposal provides no details as to how the revenues obtained from the sale of these allowances in the RGGI auction would be used. The allowances and proceeds allocated to DMME to administer the program are revenues of the state and cannot be paid to DMME but rather would have to go into the State Treasury. DMME would only be allowed to use funds appropriated by the General Assembly to cover administrative and other costs. Although not explicitly stated, DEQ has indicated its intent to at least in part direct the 5% set-aside to encourage energy efficiency projects. To the extent the set aside is directed toward incentivizing energy efficiency, both demand- and supply-side energy efficiency improvement programs, including voltage optimization and other transmission and distribution efficiency improvements, should be eligible. Eligibility should include programs that help reduce carbon emissions such as infrastructure for electric vehicles.	As discussed elsewhere, DMME will determine how the set-aside is implemented, whether through incentivizing energy efficiency, other transmission and distribution efficiency improvements, or something else. DEQ agrees that both demand- and supply-side energy efficiency improvement programs should be eligible.
98. Dominion Energy	DEQ must explain adjusting the Virginia emission cap on the basis of banked allowances amassed over 2018-20 by affected entities in other RGGI states that Virginia affected sources will not be holding since Virginia entities will not become subject to an emissions cap or required to hold allowances until 2020. RGGI states were not subject to such adjustments through the first two 3-year compliance periods. Banking should be unlimited. Provisions to adjust emissions caps or withhold allowances based on volume of banked allowances should be delayed to provide time for the Virginia carbon market to mature. Similarly, there is no justification for applying the ECR mechanism at the inception of the Virginia program. Virginia sources will not be carrying any banked allowances during the initial compliance period. Under the RGGI model rule, states have discretion whether to implement the ECR	DEQ has developed the rule with the intent of linking to RGGI, because linking to a larger, well-functioning, existing program is a reasonable, efficient way to reduce emissions from Virginia units at the lowest cost. In establishing the provisions of the program and analyzing its potential impacts, DEQ has taken into account the provisions in the rule, including the adjustment of the allowance budget over the course of the program, and

	mechanism; New Hampshire and Maine do not intend to implement this mechanism. Accordingly, DEQ should allow the Virginia market to mature before applying any mechanism that would artificially reduce the emission cap and increase compliance costs by driving up the allowance price. Another concern with adjustment mechanisms is that compliance entities will be compelled to purchase allowances from noncompliance entities to obtain enough allowances to comply with reducing caps. This will be further complicated by the ECR that will reduce the bank of allowances. It is likely that the cost of allowances will increase as noncompliant entities seek a return on their investments, which increases compliance costs. The adjustment provisions should not be incorporated into the Virginia program without further evaluation. Applying adjustments and restrictions to the unlimited use of allowance banking would complicate and limit the very emissions trading system that the RGGI states have praised for its success.	implementation of the ECR. Both of these features were included in the modeling and analysis conducted for the program and that analysis showed the program can be implemented yielding substantial benefits at a modest cost. The bank adjustment, CCR and ECR are all required elements for participating in the RGGI program. The ECR will only be triggered if the allowance prices are lower than expected and only to the extent the winning bids at a particular auction are lower than the ECR trigger price. The ECR mechanism is designed, therefore, to operate only in those circumstances where allowance prices are below the ECR trigger price.
99. Dominion Energy	The RGGI program has always allowed for a multi-year compliance true-up timeline. For the first 6 years of the program, affected entities were required to demonstrate compliance on a 3-year cycle. Beginning in 2015, the program was modified to a tiered 3-year compliance obligation. This compliance obligation will be maintained under the revised RGGI program and model rule that takes effect beginning in 2021. This allows for a smooth transition for RGGI compliance entities into the next phase of the RGGI program with a new 3-year compliance true-up (2021-23) following the last 3-year compliance true-up (2018-20) under the current phase. DEQ proposes to implement a similar tiered 3-year compliance approach. We generally support a multi-year compliance approach as it affords compliance entities flexibility in meeting compliance obligations. Note that the CPP also allowed for a 3-year compliance true-up. Aligning true-up requirements with compatible 3-year compliance cycles in RGGI makes sense.	Support for the proposal is appreciated.
100. Dominion Energy	With the Virginia program starting in 2020, the regulation would impose a one-year initial compliance timeline (to address 2020 emissions) before converting to a 3-year compliance cycle. DEQ explains that initial 2020 allocations and a one-year compliance true-up obligation is needed to align the Virginia program with RGGI's current 3-year compliance cycle. This single year	DEQ acknowledges the commenter's concern. The department was faced with a choice: either abbreviate the normal 3-year compliance period to 1 year in order to align the

	compliance requirement places a burden on Virginia generators that no other compliance entities in the RGGI program have. In order to address this issue, DEQ should defer the implementation of the Virginia carbon program until 2021. This would fully align the compliance obligations under the Virginia program with RGGI's current 3-year cycle and provide a smoother transition to linking with the RGGI allowance system.	program start with RGGI (2021), or delay implementation and enable sources to obtain a full 3-year compliance period. There are advantages and disadvantages to either approach. DEQ based its final decision on what would best meet the overall program goal of smoothly linking to RGGI. Starting the program on time and limiting facilities to a 1-year compliance period does impose an immediate burden on sources; however, this will benefit them in the long run by giving them a longer term compliance period as well as a smooth transition to the RGGI program. Adjusting as the commenter recommends would provide relief in the short term but put facilities on a steeper, more rapid compliance period overall.
101. Dominion Energy	We support adoption of the CCR which would provide a pool of additional allowances for sale in the consignment auction if the costs of allowances exceed a certain threshold. Such a mechanism is needed to address unexpected scenarios and to address potential adverse impacts on electric system reliability, and could also offer affected entities protection in terms of not being penalized for fewer emission reductions resulting from the unpredictable performance of renewable generation units.	DEQ agrees with the commenter that the CCR is a needed mechanism; see comment 136 for more detail as to how the CCR works.
102. Dominion Energy	The regulation should include offsets as allowed under the RGGI model rule, expanded to allow offsets that will encourage the reduction of emissions from electrification of other sectors of the economy, such as transportation. EVs and charger installations should be allowed to generate offsets. In 2016, more carbon emissions came from the transportation sector than the power sector. The regulation should allow reductions in emissions from sulfur hexafluoride (SF_6), one of the most potent GHGs. This offset category was eliminated from the RGGI model rule on the basis that, to date, there had been no SF_6 projects finalized in any RGGI state. One of the reasons for this has been may be the overall low RGGI allowance prices coupled with an abundant supply of RGGI allowances rendering administration costs undesirable. However, the more stringent RGGI cap and	As discussed in the response to comment 26, offsets are not being included in the regulation at this time. DEQ agrees that control of carbon pollution from the transportation sector is important, and may be addressed in another action.

	new mechanisms designed to minimize the allowance bank and drive the allowance price higher may now make these projects more viable.	
103. Dominion Energy	Table 140-5A in 9VAC5-140-6210 D 2 and Table 140-5B in 9VAC5-140-6210 E 2 should be corrected to reflect that the annual number of CCR and ECR allowances listed are in million tons.	The proposal has been corrected accordingly.
104. DuPont	DuPont acquired the cogeneration units adjacent to its Spruance Plant as the supply contract expired and the previous owner discontinued operation. DuPont has a long-term agreement with Veolia to operate and maintain the cogeneration units that supply the Spruance powerhouse on the manufacturing campus. Veolia plans to upgrade the utilities to be more efficient, and enhance performance and reliability, which will help DuPont reduce its costs and environmental footprint. The unit that Veolia will operate and maintain for DuPont is a combined heat and power (CHP) unit. DEQ exempts certain industrial CHP units under 9VAC5-140-6060 B. However, this exemption requires that the CHP unit be owned by the industrial end user rather than a third party. DuPont has engaged Veolia to utilize their specialized expertise to operate and maintain the industrial utility, while allowing DuPont to focus on manufacturing. Rather than regulating CHP ownership, DuPont suggests that DEQ remove the phrase "owned by an individual facility and" so that 9VAC5-140-6040 B reads: "Exempt from the requirements of this regulation is any fossil fuel power generating unit located at that individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility."	DEQ agrees that the phrase "owned by an individual facility" should be removed; see the response to comment 65. Under the RGGI Model Rule, facilities that provide less than 10% of their power output to the grid are exempt from compliance obligations and the proposal has been revised accordingly. The regulation has been further amended in order to address CHPs with more clarity; see the response to comment 74.
105. Environmental Defense Fund (EDF)	EDF strongly supports regulations to limit carbon pollution from Virginia's power sector because Virginia has profound public health and climate benefits at stake. An overwhelming majority of Virginians agree: 87% support Virginia continuing to reduce carbon emissions from power plants. The board has clear existing authority to regulate carbon emission through a statewide cap, trading program, a revenue-neutral consignment auction, and linking with RGGI. EDF supports Virginia linking to RGGI and aligning its proposed rule accordingly. An expanded regional carbon trading market in which Virginia links with the existing RGGI program has a number of benefits, including greater liquidity, streamlined administration, and additional opportunities for cost-effective compliance. The benefits of cost-effective CO_2 emission reductions from a well-designed CO_2 trading program are clear. For example, from 2012-14, RGGI added $1.3 billion in economic value in the region and led to the creation of more than 14,000 jobs. By finalizing a strong CO_2 trading program that links with RGGI, Virginia is poised to garner significant economic, public health, and environmental benefits as well.	Support for the proposal is appreciated.

	Virginia has tremendous opportunity to accelerate clean energy deployment and expand the role of renewables and energy efficiency in the state. Virginia has an estimated 89,000 MW of onshore and offshore wind capacity potential that could serve an electric load that outstrips the state's own needs. Virginia can also take advantage of tremendous solar capacity potential. Shifts in Virginia's power sector reflect national trends toward low carbon electricity. In Virginia, power sector CO_2 emissions declined by 24% from 2005-15. These reductions have been driven by falling costs of renewable energy, low natural gas prices, changing consumer preferences, and policies that incentivize clean energy deployment.	
106. EDF	Thirty million tons should constitute the upper bound for the starting budget in 2020, with strong evidence indicating an even lower budget. In addition, the budget should decline annually by a tonnage amount of at least 3% of the 2020 budget--which is in alignment with the existing RGGI program--and consider a more stringent rate of decline. Recognizing that the ability to accurately predict future emissions based on current data has limitations, EDF also recommends DEQ provide for a mechanism to adjust the base budget in 2020 or 2021 if actual emissions are lower than projected. The 2020 budget should be at or below emissions that would have occurred under a BAU scenario. This is crucial in order for the program to drive additional CO_2 reductions beyond BAU, as well as greater near-term emission reductions in the early years of the program, enabling more cost-effective reduction pathways and opening the door to achieving higher levels of mitigation over the long-term. A starting base budget can also be lower than expected emissions under BAU, since covered facilities will have time to plan ahead for compliance with the regulation--and in fact, have already had time to anticipate the general direction of the regulatory framework given the policy direction outlined in ED 11 and the ongoing rulemaking process. Cost-effective abatement opportunities in the power sector are readily available. Modeling suggests that Virginia power sector CO_2 emissions under BAU in 2020 could be as low as 24 million tons. In 2017, DEQ projected Virginia power sector emissions would be 33-34 million tons in 2020, using the Integrated Planning Model (IPM) and assumptions from Annual Energy Outlook (AEO) 2017, Dominion's 2017 IRP, and the RGGI 2016-2017 Program Review. The Natural Resources Defense Council (NRDC) in 2017 projected BAU emissions would be 32.8 million tons in 2020, using assumptions from AEO 2017. However, more recent NRDC modeling conducted in	The 2020 budget reflects the reference case used to determine the proposed base budget, and was at or below emissions that would have occurred under a BAU scenario. As discussed in the response to comment 37, a cap of 28 million tons has been selected. Because of the importance of aligning the Virginia program as closely to RGGI's as possible, the cap and rate of decline must align. This will ensure that the program operates as effectively and efficiently as possible.

	2018 used updated assumptions to project BAU emissions of 28 million tons in 2020. Meanwhile, The Rhodium Group projected BAU emissions well below DEQ's forecast, as low as 24-25 million tons in 2020, with cumulative emissions of 247-277 tons of CO_2 in 2020-30. These additional modeling efforts suggest DEQ's original projections of 2020 BAU emissions are likely to be overestimates. As new data become available, projections of 2020 BAU emissions could be expected to decline further. Recent announcements of fossil fuel deactivations, as well as new developments for renewable energy and energy efficiency, further indicate the power sector is becoming cleaner, and demonstrate a pace toward a lower-carbon electric sector in Virginia that is challenging for modeling efforts to fully capture. Clear trends toward a cleaner power sector in Virginia reflect an ongoing transformation toward a low-carbon future for the U.S. electric power sector. As of April 3, 2018, 1,721 MW of coal and natural gas generating capacity is now slated for deactivation by March 2019, according to PJM. In 2016, these units emitted 3.87 million tons of CO_2. In 2017, the units emitted 1.71 million tons. Meanwhile, recent developments suggest a promising future for zero-emitting solar and wind generation that could reduce Virginia emissions by displacing fossil fuel generation. As of April 2018, a total of 3,621 MW of solar capacity in the PJM interconnection queue is expected to enter into service by the end of 2019. The Virginia Solar Energy Development and Energy Storage Authority reported that as of November 2017, 2,703 MW of solar was under development in Virginia. In March 2018, new energy legislation in Virginia declared 5,000 MW of new solar capacity and 16 MW of offshore wind capacity to be "in the public interest." New energy legislation also paves the way for Virginia to deploy more cost-effective energy efficiency, which, by reducing demand for electricity, can contribute to avoiding CO_2 emissions. These trends combined with recent modeling indicates that 2020 BAU emissions are likely to be lower than initially estimated and could continue to decline between now and the beginning of the program. EDF recommends that DEQ set a base budget that starts no higher than 30 million tons in 2020, but encourages DEQ to consider evidence from recent modeling and power sector trends that supports the setting of a base budget that starts below this upper bound. A lower starting budget can also facilitate additional benefits that can result from a more environmentally protective program. A base budget that starts below 30 million tons would be consistent with a trajectory for Virginia to reach zero carbon emissions from the power sector by mid-century. A lower budget would also help	

	drive additional near-term emission reductions, unlocking the benefits of taking earlier actions to mitigate climate change. With annual average temperatures in the U.S. having increased by approximately 1.0°C in the last 115 years, the impacts of climate change are already apparent. Increased magnitudes of temperature rise are likely to further increase the prevalence of harmful climate changes worldwide, including severe weather events, extreme temperatures, extreme precipitation changes, and impacts to natural ecosystems and human necessities such as food security. Given cost-effective opportunities to reduce carbon emissions in the electric sector, and the lower overall emissions that can result from securing power sector decarbonization in advance of other sectors switching to electricity, it makes sense that the electric power sector should do more than its proportional share in reducing emissions, and follow a steeper trajectory earlier in time. In order to assess whether Virginia's emissions budget is consistent with this trajectory, DEQ can evaluate historical emissions data from 2016 and 2017. Using this data as one set of possible benchmarks, a straight-line decline from 2016 or 2017 emissions to zero by 2050 is consistent with 2020 emissions of 29-30 million tons or less, supporting a base budget that starts below 30 million tons in 2020. The Fourth National Climate Assessment finds, "Net cumulative CO_2 emissions in the industrial era will largely determine long-term, global mean temperature change. A robust feature of model climate change simulations is a nearly linear relationship between cumulative CO_2 emissions and global mean temperature increases. … Increasing the probability that any given temperature goal will be reached therefore implies tighter constraints on cumulative CO_2 emissions. Relatedly, for any given cumulative CO_2 budget, higher emissions in the near term imply the need for steeper reductions in the long term." Furthermore, a number of studies find that the timing of efforts to reduce CO_2 emissions can significantly impact the economic and environmental costs of action. Delayed action requires significantly accelerated mitigation efforts in later years to achieve the same cumulative emissions goals. Studies show that delaying mitigation efforts can increase the economic costs of necessarily more ambitious mitigation in the future. Delayed action also increases the risk of overshooting cumulative emission targets. Conversely, prioritizing emission reductions today can enable long-term mitigation to be more cost-effective and increase the likelihood of keeping temperature increases below target limits. By setting a lower 2020 starting budget, Virginia can facilitate long-term economic and environmental benefits of prioritizing early emission reductions and further limit cumulative CO_2 emissions from the power sector.	

	The RGGI states have determined a regional cap for 2021-30 that declines by 2.275 million tons per year after 2021--approximately 3% of the 2021 cap--resulting in a 30% reduction in the cap from 2020-30. Virginia should achieve at least a similar level of reductions as it contemplates linkage with RGGI. Furthermore, ED 11 directs DEQ to create a rule to reduce CO_2 from the power sector that provides for a "corresponding level of stringency" with CO_2 limits in other states. DEQ should also consider a steeper decline, considering the benefits of prioritizing near-term reductions and of maintaining consistency with a trajectory to zero emissions by midcentury, as discussed above. For example, a pathway to zero emissions by 2040 could imply a yearly decline equivalent to 5% of the 2020 budget, while a path to zero emissions by 2050 could imply a yearly decline equivalent to 3.3% of the 2020 budget. A steeper rate of decline at the program outset, even while retaining a lower rate of decline in later years, would also facilitate further limits on cumulative emission reductions and additional near-term reductions.	
107. EDF	EDF recommends a mechanism to adjust the emissions budget as new data and analysis emerge. An adjustment could be made to lower the emissions budget in order to achieve additional emission reductions if abatement opportunities are more readily achievable and cost-effective than forecasts show, as well as to optimize market function. DEQ could establish a mechanism to automatically adjust the budget if certain conditions are triggered, or provide for a manual adjustment early in the program. An automatic adjustment mechanism could use a pre-determined formula to tighten the emissions budget under certain conditions. DEQ could establish such a mechanism to adjust the base budget in early years of the program if actual emissions are lower than projected--not unlike how RGGI has adjusted its cap in the past to account for banked allowances. DEQ has a range of options for the timing of any such adjustment, and should consider factors such as the availability of new emissions data, ease of administration, and the timing of RGGI auctions, compliance periods, and the 2021 bank adjustment. Alternatively, DEQ could provide for a manual adjustment of the emissions budget when new data becomes available--for example, 2019 or 2020 actual emissions from the affected power sector units. Virginia has appropriately included the ECR and withholding of allowances in alignment with RGGI's Model Rule. DEQ should harmonize the minimum reserve price for the Virginia program with the minimum reserve price in RGGI. There is a continued need for emission reductions beyond 2030 to achieve climate goals and protect Virginians from the impacts of carbon pollution. DEQ should participate in RGGI program	As part of linking to RGGI, it will be essential for Virginia to participate in RGGI market controls--such as the CCR and ECR--and in periodic reviews to adjust the program as needed. There is no need for Virginia, at this point, to develop its own preemptive mechanisms. DEQ appreciates the need to respond quickly to unpredictable market fluctuations and other unknown issues; however, the best approach to do so is in concert with the other RGGI states. Should a definite state need arise, a Virginia-specific remedy may be implemented.

	reviews. Periodic program reviews are an important means to assess program success and make changes to strengthen the program. It is important for DEQ to provide as much long-term certainty around carbon regulation as possible--market certainty will contribute to a successful emissions market, and can also help ensure Virginia is at the table as a leader on climate policy in the future.	
108. EDF	EDF supports allocating allowances to covered sources with an updating output-based approach, and consignment of allowances to the RGGI auction. This design smooths integration with RGGI, facilitates transparency and market efficiencies, and mitigates leakage. Consignment auctions are a proven method to facilitate transparency and price discovery. Successful examples of consignment auctions include the federal Acid Rain SO_2 Trading Program and California's Cap-and-Trade Program. A consignment auction in Virginia should be able to integrate seamlessly with the RGGI auction and key design elements including the price floor and ECR. Consignment auctions can create further incentives to reduce electric sector carbon emissions through a carbon price signal reflected in electricity rates. Furthermore, measures can be taken to provide benefits to ratepayers alongside a carbon price signal. Analyses conducted by EDF and RFF in the context of the CPP found that an updating output-based approach can be an effective means of mitigating emissions leakage--wherein carbon emissions shift out-of-state or to sources not covered by the program through, e.g., shifting generation. Modeling conducted by RFF found that an updating approach to allocate 100% of allowances to a subset of eligible sources under the CPP (as opposed to a historic approach) could reduce leakage by up to 64% compared to a mechanism that allocated only 5% of allowances with an updating output-based approach. Similarly, EDF analysis found that allocating all or nearly all CO_2 allowances with an updating output-based approach could significantly reduce leakage. EDF encourages Virginia and other RGGI participating states to monitor and evaluate whether and to what extent emissions leakage might be occurring on an ongoing basis, and evaluate additional opportunities to effectively mitigate any leakage that may occur.	The commenter's remarks on how the updating output-based approach and consignment of allowances to the RGGI auction will address leakage are acknowledged. DEQ agrees that these mechanisms, along with robust program reviews for which RGGI explicitly monitors leakage, will discourage and limit emissions leakage. See the discussions under the response to comment 91.
109. EDF	Industrial power plants over 25 MW in size are a source of carbon pollution that DEQ proposes to exempt. Much of the literature on carbon market designs suggests that broader inclusion of sources can lead to more cost-effective and efficient outcomes. Industrial power plant sources may be included in future climate policies and Virginia can help provide regulatory certainty to these facilities by bringing them into the program and drive investments to reduce emissions now. In order to meet	See the response to comment 65 for a discussion of how industrial facilities will be handled. DEQ agrees that energy efficiency and renewable energy are important elements in a carbon reduction program, and will

	our climate goals, more emitters will need to reduce emissions. There are extensive, cost-effective opportunities for improving efficiency and increasing renewable energy use across industrial sources and DEQ should include these sources in the program.	likely continue to improve in Virginia for a variety of market- and pollution control-based reasons.
110. EDF	A strong trading program can provide important benefits for communities overburdened by pollution. Without affecting timely finalization of the rule, DEQ should conduct ongoing analysis and monitoring to ensure communities disproportionately impacted by air pollution benefit from efforts to abate carbon pollution. This analysis could include a geospatial EJ screen using demographic and environmental indicators to identify disadvantaged communities. DEQ should continue to work with affected communities and other stakeholders, such as the EJAC, to identify instances of adverse economic or pollution impacts on disadvantaged communities and take appropriate action to mitigate the effects. DEQ should also continue to engage meaningfully with EJ stakeholders and disadvantaged communities as the agency works to finalize this rule and implement the program. EDF commends DEQ for its efforts to date to hold public hearings across Virginia and invite deep engagement from diverse stakeholders, and encourage DEQ to continue this practice.	As discussed in the response to comment 55, the EO 73 EJAC Council will take the lead on directly addressing environmental justice issues. DEQ will continue its public outreach efforts in such a way as to maximize public participation from all Virginians.
111. Forest Products Industry National Labor Management Committee (LMC)	LMC opposes joining RGGI due to concerns it would increase electricity and natural gas prices for businesses and consumers. The following language should be included in the regulation: "Forest biomass, including forest products manufacturing residuals, should categorically be treated as carbon-neutral whether or not it is co-fired with fossil fuel." The carbon profile of biomass is not at all altered when co-fired with other fuels. The biomass portion of the fuel mix has the same characteristics no matter what fossil fuel it may be co-fired with. It is the characteristics of the biomass feedstock, not of the power generation process or facility, that support treatment of biomass as carbon neutral. Additionally, LMC strongly urges the regulation not be expanded beyond its focus on utilities to also apply to industrial boilers. ED 11 pertains exclusively to controlling CO_2 emissions from electric power facilities. The Economic Impact Assessment, the direction given to the Regulatory Advisory Panel, the emissions and economic modeling conducted by DEQ and its consultants, and DEQ's written and oral information supporting the proposal indicated that the regulation applied only to the electric power sector.	See the response to comments 65 and 67 for further information on rule applicability.
112. GRID Alternatives Mid-Atlantic	We understand the consignment is designed to be revenue neutral. However, DMME will have a contract with a third-party administrator that would sell allowances allocated to DMME and make the funding available for use in a variety of programs to help reduce CO_2 emissions. Accordingly, one of DMME's strategies is to accelerate the adoption of energy efficiency practices	DEQ recognizes the value of low-income solar programs as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the

	and expand the deployment of renewable energy. This funding could be utilized to create new economic opportunity in the state through solar energy. Solar provides long-term financial relief to families struggling with high and unpredictable energy costs, living wage employment opportunities in an industry adding jobs at a rate of 20% per year, and a source of clean, local energy sited in communities that have been disproportionately impacted by traditional power generation. Virginia solar jobs increased by 10% in 2017, and the state now has over 3500 solar workers. Virginia is poised to experience 1.5% solar jobs growth in 2018. Low-income ratepayers pay a disproportionate amount of their income on utility bills. These customers stand to benefit most from solar energy, and must be prioritized through targeted policies and programs. The proposal assumes that all revenues raised from the auction by utilities are returned to ratepayers. In the case of distribution utilities dependent on other wholesalers for power, such as rural electric cooperatives and municipal electric entities, those wholesale contracts could impose costs on those dependent purchasers with no mechanism--and nothing that DEQ could make a requirement--for the wholesaler's auction revenues to offset those costs or return those revenues to the underlying load that is responsible for paying those costs. There may be solutions to this issue; however, those solutions would be outside DEQ's purview, either involving an order from the SCC, a mandate to run auction revenues through a FERC formulary rate in a certain way, or legislation. Low-income consumers that use electricity should not pay for the costs of carbon regulation without also receiving the benefit of revenue, if any, from allowance auction proceeds. The proposal does not fully address this issue. GRID Mid-Atlantic has seen the benefits of low-income solar programs in markets across the country. We recommend the regulation directly benefit low-income ratepayers with a solar program funded by DMME's allowance funding. A low-income solar program would have the goals of significantly reducing the electrical energy burden of Virginia's low-income ratepayers and training the next generation of solar workers. This type of programming would complement DMME's strategic objective to expand the deployment of renewable energy and overall reduction of CO_2 emissions.	allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement that set-aside. DMME may, at the appropriate time and in accordance with its regulations and policies, implement a low-income solar program set-aside. As discussed in the response to 55, affected communities will be monitored on an ongoing basis to assure that no disproportionate impacts are experienced. Note that the trading program as well as how the costs of energy in Virginia are arrived at are open and transparent. There will also be numerous opportunities to identify and remedy any identified impacts.
113. International Emissions Trading Association (IETA)	IETA welcomes this opportunity to voice strong support for the proposal. More than 50% of the world's economy is subject to some form of carbon pricing, most of which is under cap and trade systems. This growing coverage includes major international trade partners and the entire RGGI collaborative. Virginia's proposed program allows the use of market-based mechanisms and trading of CO_2	Support for the proposal is appreciated, as is the commenter's discussion of RGGI's attributes.

	allowances. It provides an important link to RGGI's program, enabling Virginia market participants to have access to a bigger, more efficient market. 9VAC5-140 will allow Virginia to join the other RGGI states as a leader in cutting emissions that lead to climate change and air pollution, while providing opportunities for in-state clean economic growth and business development. The rule would also provide regulatory certainty to Virginia's electric generation sector, including a clear price signal and incentive for electricity generators to invest in innovative lower carbon technologies. IETA sees the program having 4 fundamental advantages: flexibility, cost-effectiveness, linkability, and building on the proven success of emissions trading systems globally--and most importantly--in the context of the RGGI cap and trade program. The program accesses regional allowance auctions and gives participants across the RGGI region the opportunity to participate in the Virginia market. This will provide a broad market for program revenue, price discovery, and market liquidity. Issuing allowances to generators based on their current GHG emissions and allowing them to sell excess allowances creates an incentive for generators to be innovative in their carbon investment and compliance strategies. Compliance flexibility afforded by the program will ensure that emission reductions are realized cost effectively. Cost-containment design elements, such as an auction reserve price and price ceiling, will guarantee that the carbon price does not go above or below acceptable ranges. This approach will reduce administrative burdens for government. Virginia will be able to take advantage of economies of scale to reduce compliance costs while meeting GHG reduction goals while maintaining Virginia's autonomy and ability to act in its best interest. Linkability will also allow Virginia to take advantage of systems such as COATS without the need to develop and operate new systems and infrastructure. IETA encourages Virginia to establish an offsets policy and framework that could take advantage of existing methodologies developed by RGGI and the Western Climate Initiative. Over nearly a decade, RGGI has resulted in significant environmental and socio-economic benefits, including emission reductions and more than $2.76 billion in net economic gains. Virginia's cap and trade program can demonstrate that economic growth and carbon reductions can work together. As a global organization, IETA is aware of the broad and powerful role that programs like cap and trade can play in efforts to address the climate challenge. Adoption of 9VAC5-140 is a critical step that Virginia must take in order to reduce emissions and air pollution. At a time when Washington D.C. is regressing on climate	

	action and leadership, Virginia's progress could not occur at a more important time	
114. Institute for Policy Integrity, New York University School of Law	When Virginia joins RGGI, the total emissions regulated by RGGI will rise by over 40%. Thus, the choice of Virginia's emissions cap will substantially affect the total number of allowances available at each auction and may affect the stringency of the RGGI cap. Changing the stringency of the RGGI cap will, in turn, affect future permit prices, affecting all participants in RGGI auctions. In particular, power plants in other states will be able to purchase permits at a lower price, leading to less abatement. Therefore, the achievement of environmental goals by RGGI will also be a function of Virginia's cap choice. A new state joining RGGI could either increase or decrease the stringency of the total emission cap. The RGGI price is currently below the socially optimal price for a ton of CO_2, and the price ceiling in RGGI is also below this level, so a less stringent cap would result in lower social welfare when compared to a tighter cap. If Virginia's cap is set relatively tight, leading to a lower total number of allowances than required to maintain RGGI's stringency, then RGGI permit prices will increase, possibly even hitting the price ceiling. This would not constitute an inefficiency from a social point of view. In 2020 the Social Cost of Carbon will be $49. Even if the generators were paying the full CCR trigger price, which in 2020 will be $10.77, the permit price would still be too low to fully internalize the externality caused by carbon emissions. By the same token, depressing the allowance price by decreasing the stringency of the cap would lower social welfare. If Virginia chooses to issue allowances for more emissions than its generators would emit under a business-as-usual scenario (the "counterfactual emission level"), this will loosen the emission cap for all of RGGI. Unless allowance prices are at the price floor, the price will go down, causing the aggregate emissions to increase compared to a scenario where Virginia does not join RGGI. A fall in the permit price will also decrease the revenue that the other states receive from RGGI auctions. The magnitude of those adjustments will depend on the magnitude of the changes in RGGI's cap. For emissions to decrease, the number of permits issued in Virginia must be set below the counterfactual emission level. To achieve that goal, a reliable prediction of the future emissions path is required. However, developments that can significantly affect Virginia's emission levels are uncertain, for example the rate of fossil fuel retirements and additions of renewables. DEQ should discuss their forecast of state CO_2 emissions to help assess whether the allocation will be too high or too low. Virginia proposes to set the base budget at 33 or 34	Support for the proposal is appreciated, as is the commenter's discussion of trading programs.

	million allowances (while putting an additional 3.3 to 3.4 million allowances into the CCR). This might be too generous, even when future declines in the budget are considered. For instance, comments submitted to RGGI by Arcadia Center, NRDC and Sierra Club suggest that 2020 baseline should be set in the range of 30-32 million tons. The choice of the initial budget needs a sound justification given its potential impact on total pollution and permit prices. The allowance price will decrease slightly even if Virginia sets the cap equal to or just below its counterfactual 2020 emissions. This effect operates through two channels. Cheap pollution abatement possibilities may exist for Virginia's electricity generators that have already been implemented in the other RGGI states. And, if the RGGI cap is more restrictive than the cap chosen by Virginia, the total effective cap will be less stringent than without Virginia joining the system. However, the price decline will not be accompanied by an increase in total emissions compared to the scenario without Virginia. Therefore, a falling permit price, by itself, will not be informative as to whether RGGI's expansion will decrease total CO_2 emissions. As RGGI prices are already close to the reserve price, if Virginia enters RGGI with a loose cap, this will increase the probability of the ECR becoming operative. As Maine and New Hampshire do not intend to implement the ECR and will thus not withhold allowances when the trigger price is reached, this will create redistributional effects between the states. Adding Virginia generators to RGGI will improve market efficiency for current RGGI states and will help Virginia cost-effectively meet its carbon pollution reduction goals. Because of the consignment auction mechanism being used to distribute conditional allowances and RGGI proceeds, the SCC should ensure that all participants in RGGI are on an equal playing field to maintain market efficiency. One concern with the consignment auction is that some power generators in Virginia might be able to keep the revenue disbursed by RGGI, while, ideally, the consignment process should be revenue neutral for all compliance units. Regulated power producers in Virginia will be required by the SCC to pass all revenue from RGGI auctions on to state electricity consumers. The SCC will be in charge of verifying that the consignment auction is indeed revenue neutral for those units. Vertically integrated utilities could potentially gain revenue from the auctions by substituting RGGI-derived revenue for other customer support payments. Only newly conceived customer support programs should be funded using RGGI revenue to ensure that the support is additional to any other support that the generator might have offered. The SCC will need to be	

	proactive in protecting Virginia consumers to prevent behavior by generators that results in windfall revenue. Windfall revenues would place the producer at a long-run competitive advantage relative to electricity generators that participate in RGGI but that do not receive revenue from the auctions. Because conditional permits will be allocated based on electricity generation rather than CO_2 emissions, clean generators could even see their profits increase if they manage to receive revenue from RGGI. This could happen for a generator that receives more conditional allowances than it needs to buy from RGGI to cover its own emissions, consequently receiving more revenue from RGGI than it spends at RGGI auctions. If non-regulated, private generators in Virginia subject to the proposed regulation do not have a revenue neutrality requirement, those generators will receive a revenue windfall in the form of proceeds from RGGI auctions. Some of the cleanest private resources might experience a profit windfall. As a consequence, this might create a competitive advantage for private generators over regulated resources. This could send incentives for new private power generation to locate in Virginia rather than RGGI states. Even if these generators receive revenue from the auction, joining RGGI will improve market function relative to the current status quo. Right now, emitting generators in Virginia are receiving an implicit subsidy, as they are not paying for the environmental damage caused by their emissions. Internalizing this externality will eliminate the perverse incentives for high emitting generators to locate themselves in Virginia relative to other RGGI states. The pass-through of the permit price from generators to customers will determine the extent to which generators themselves face the incentive to reduce carbon emissions. If the SCC allows generators to increase electricity rates in response to the costs of purchasing RGGI permits, then consumers will face an incentive to reduce electricity consumption and invest in energy efficiency. At the same time, higher energy prices may slow down the rate of electrification of the automotive and heating sectors. To the extent that the SCC wants the incentive for abatement of CO_2 to fall on the generators, it should limit the pass-through of permit prices to consumer electricity prices, either through limits on the approved rate increases by regulated generators or through rebates of RGGI proceeds to consumers. Similarly, if Virginia aims to increase electrification of other sectors of the economy, it should prevent pass-through of permit prices to consumer electricity prices. Electricity generators in Virginia will be incentivized to reduce CO_2 emissions whether or not the consignment auction is fully revenue neutral. A requirement to hold a permit for each ton of CO_2 emitted provides a marginal	

	incentive to reduce emissions. This marginal incentive to abate will be present regardless of whether generators receive lump-sum revenue from RGGI. The RGGI-derived revenue would affect the long-run profitability of the generators if it is not distributed to consumers, so over time higher or lower emitting generators may be more likely to enter or exit the market. However, the marginal incentives to abate will be realized as long as the requirement to hold a permit to emit is in place. Moreover, were Virginia not to place any price on carbon, it would impede efficient market operation by implicitly subsidizing fossil power generators in the state. Therefore, including Virginia in the RGGI trading program will help improve market function and promote a level playing field between generators. The way in which the revenue from the consignment auction is passed to consumers will also have implications for environmental outcomes and energy demand. If consignment auction revenue is passed to consumers on a volumetric basis, consumers will see a lower price for electricity, reducing the incentive to pursue energy efficiency but also preserving the incentive for electrification. The design of the regulation needs to balance those trade-offs. Finally, the consignment auction mechanism also creates different incentives among the generators inside Virginia. Because the permit allocations and updates are based on net electricity output, the cleanest fossil fuel plants will have an incentive to expand their generation compared to higher emitting generators. This incentive should make the Virginia fleet even cleaner, leading to quicker decreases in emissions. In sum, adding Virginia generators to RGGI will increase environmental quality and improve market efficiency.	
115. Lena Lewis	I strongly support implementing carbon cap and trade of power plants. I congratulate DEQ on writing strong carbon cap-and-trade policy that will move Virginia forward in protecting our citizens from the worst impacts of climate change. I support linking with RGGI, which has a proven track record of success in reducing carbon emissions while keeping state economies strong. The purpose of cap-and-trade is to cause people to make different decisions than they otherwise would without the cap. Exempting biomass will create an incentive to cut down more forests, and will create the incentive for more biomass plants to be built, or for plants to be converted from fossil fuel to exclusively biomass. This will increase the incentive to cut down forests in Virginia. In addition to removing CO_2 from the atmosphere, these mature forests provide many other ecosystem services, such as cleaner drinking water, reduced erosion, and oxygen production. Keep in mind	Support for the proposal is appreciated. See, for example, comment 67 for further discussion of biomass, and comment 65 for more information on the industrial exemption. A base cap of 28 million tons tons has been selected; see the response to comment 37 for additional information. As discussed elsewhere, the purpose of the regulation is to control carbon pollution emitted by fossil fuel-fired electric generating facilities.

	that carbon is just one element among many in our ecosystems. Carbon policy that exempts biomass risks increasing the destruction of biodiversity in forest ecosystems and reducing other benefits that they provide. Proponents of biomass say that it is carbon neutral because the energy source will absorb CO_2 as it grows back. A large body of scientific literature explains that the truth is not so straightforward. One essential question is the time frame needed in order for a harvested forest to grow back enough to absorb all of the carbon released from burning. This time frame depends on many variables, including age of trees, species, amount of fossil fuels required to harvest trees, temperature, and growth rate of species. We are on the verge of a tipping point with climate change. Harvesting forests for biomass fuel will increase carbon emissions in the near term. In the decades it will take for those forests to reabsorb that carbon, the added CO_2 in the atmosphere will contribute to accelerated release of carbon from melting permafrost in the tundra and reduced albedo in at the poles due to melting ice cover. Some public comments express concern that including biomass in the carbon cap will hurt the paper industry and tree farmers. The point of a market-based solution is to change behavior. If paper factory owners assess that carbon allowances no longer make it profitable to burn residuals, they are not required to burn their wood waste. Nor are they stuck in a situation of profit loss. Paper factory owners are free to innovate to find new ways to use residual wood waste. They may discover a new application that brings in more money than burning waste wood. Market-based solutions such as cap-and-trade promote innovation. Exemptions do not. The climate crisis calls for innovation across all sectors of society, and should not exempt the paper industry or the biomass industry. Though Virginia does not currently have large power plants that incinerate municipal or industrial waste to produce energy, a cap that does not include them will promote their development. Because MSW burned for energy is predominantly plastic that could otherwise be recycled, it is a potential source of carbon emissions and would promote the destruction of otherwise recyclable materials. Rather than wait for these plants to be built before regulating them, the regulation should state that plants burning MSW and industrial waste must retire carbon allowances to do so. The level of the initial cap is important because subsequent reductions are percentages, not set amounts. DEQ's proposed initial cap of 33-34 million	

	tons is based on the electricity utilities' flawed projections of energy demand. The point of the cap is to reduce carbon emissions, not to give utilities a new source of revenue through selling allowances. Such a high number of allowances will flood the market, reducing the clearing price of allowances in the RGGI market and reducing revenue for RGGI states. Furthermore, a cap of 33-34 million will not change Virginia's carbon emissions. The cap must put downward pressure on carbon emissions from the first year. Virginia's electricity consumption is growing very slowly. Expected electricity demand growth over the next 15 years is less than 1% a year. The DEQ scenario of 33-34 million tons assumes an annual growth rate of 1.9-3%. It does not take into account the amount of utility scale solar projects already in the construction pipeline, nor the increase in rooftop solar. Anticipated energy demand depends on which historical data is considered. When looking at 2012-16, one could conclude that energy demand is increasing. However, 2012 had a mild winter and cool summer. Energy demand from 2005-16 resulted in emissions of just under 32 million tons of CO_2. Therefore, the cap should be lower than 32 million in 2020 to account for increased solar and natural gas, and to put downward pressure on emissions from the first year. Even if a business-as-usual scenario predicts a decrease in carbon emissions, the purpose of a cap is to decrease carbon emissions by a greater amount than under business as usual. Therefore, I recommend a starting cap of 30 million tons.	
116. Malin Moench	My comments go to the relative harm that coal, natural gas, and biomass do to the climate and to human health from the toxins that they generate when they generate electric power. Incentives should double down on energy efficiency and on renewables that are truly clean. The Clean Power Plan provided for gas-shift emission rate credits for utilities that replace coal-fired production with gas turbine production. Virginia's plan should not include such credits. Producing and burning natural gas is as climate forcing as coal largely because the effect of fugitive methane is far bigger. About 3.8% of conventional natural gas production and about 12% of shale gas production is fugitive methane. After properly accounting for fugitive methane, and using a 20-year impact analysis, it may very well be that gas-shift penalties are needed, rather than gas shift credits. Biomass should not be eligible for renewable energy credits. Burning wood scraps for power is not climate neutral. Per Btu, it emits 10-35% more CO_2 than burning coal, depending on the moisture content of the fuel, combustion efficiency of the plant, and processing losses. Regrowth of clear-cut hardwood forests will not offset the higher CO_2 intensify of burning wood scraps until the year 2100. By then, under current CO_2 emission	The commenter's observations about biomass are appreciated. Although toxic and criteria pollutants from biomass are indeed a source of concern, they are not regulated by this particular program, nor is methane. These pollutants are more appropriately addressed in other areas of the board's regulations. See the response to comment 67 for more detail.

	trends, the world will have blown past critical tipping points in the carbon cycle. Burned biomass also exceeds coal in its emissions of toxins. Like coal emissions, wood smoke is an extreme public health hazard, containing over 200 toxic chemicals and particulate matter. The component of burned biomass that harms human health the most is fine particulate matter. Wood-fired power plants and coal-fired power plants are primarily neurotoxin and carcinogen factories from a physician's point of view, but on a Btu-equivalent basis, wood-fired is much worse. They should not get a free pass.	
117. National Alliance of Forest Owners (NAFO), Virginia Forestry Association (VFA)	Excluding biomass CO_2 emissions is good environmental policy and supported by scientific studies. There is an extensive record supporting a decision to differentiate biogenic CO_2 emissions from fossil fuel GHG emissions. Importantly, there is scientific consensus that, because it is part of the natural carbon cycle, the potential for impacts on atmospheric GHG levels from biogenic carbon is fundamentally different than fossil carbon. In the forests of Virginia, biogenic CO_2 emissions are more than balanced by carbon sequestered in growing forests. Studies show that combusting biomass for energy offers substantial GHG mitigation benefits when compared to fossil fuel. There is strong evidence that forests are currently being managed sustainably and will be for the foreseeable future. Thus, when forest carbon stocks are evaluated over appropriate time and spatial scales, there is ample support for the proposition that forests are capable of meeting increased demand without reducing overall forest carbon stocks. It is well-established that all wood products, including biomass combusted for energy, are part of the natural forest carbon cycle. CO_2 is sequestered in forests through photosynthesis and emitted through decomposition and combustion. As long as forest carbon stocks remain stable or increase over time, biomass energy and other forest product uses do not increase atmospheric GHG. In contrast, CO_2 emissions from fossil fuel combustion permanently increase atmospheric GHG concentrations because they release carbon that has been geologically stored for millennia. Sustainable management of forested lands provide distinct climate change mitigation benefits which reduce net GHG emissions over time: 1) durable forest products continue to store carbon for decades after harvest, 2) manufacturing forest products is much less carbon-intensive than alternative products such as concrete or steel, and 3) biomass used for energy can directly displace fossil fuel emissions over multiple harvest cycles. Many studies evaluating biomass energy have found significantly lower net GHG emissions when compared to fossil fuel. Recent studies have attempted to quantify in	See comment 67 for further discussion of biomass.

	absolute terms the GHG mitigation benefit of substituting biomass energy for fossil fuels. These studies also identify substantial reductions in GHG emissions, but do not directly answer the question whether biomass combustion for energy results in any net CO_2 emissions. However, these studies consistently conclude that active forest management focused on supplying forests products and biomass energy produces the greatest GHG mitigation benefits from forested lands. Stability or growth in forest carbon stocks is essential for establishing that biogenic CO_2 emissions do not increase atmospheric CO_2. If forests are converted to other land uses after harvest, the carbon cycle is broken. Thus, given urban development and other external pressures, it is essential to ensure that forest carbon stocks are not depleted as a result of biomass energy. However, projections by the U.S. Forest Service suggest that forest stability will continue for decades to come. Whether viewed nationally or regionally, studies consistently find that forest carbon stocks have remained stable or increased over the past 60 years despite increases in demand for forest products. Timberland in Virginia has a highly positive net growth/removal ratio, meaning that through sustainable management, our forests are growing more than twice as much wood as is harvested. Despite the stability in U.S. forest carbon stocks over time, some have expressed concern that increased demand for biomass energy will reduce the amount of carbon that would otherwise be stored in forests. However, these concerns are inconsistent with the market factors that influence forest management decisions. Studies have repeatedly found that forest owners will respond to increased demand for biomass energy (or any other forest product) by increasing production, and thereby increasing forest carbon stocks. In the case of biomass energy, such responses can include increased consumption of existing harvest residuals, increased productivity through management practices, and land use changes. Biomass energy relies on low-cost biomass feedstocks to remain competitive with other types of energy. Thus, biomass energy feedstocks are commonly composed of residues and other low-grade feedstocks. In contrast, high-grade trees are reserved for saw timber and similar products that command higher prices and generally result in products that store carbon for decades. Given the price differential between low-grade feedstocks and saw timber, it is unlikely that high-grade, mature trees would ever be harvested exclusively for energy production. While increased demand for biomass energy could increase prices to some degree, even optimistic projections would not raise feedstock prices to the point that landowners would manage forests for energy	

	instead of saw timber. NAFO and VFA support the proposal to exclude 90-100% biomass-fired facilities from the rule. The proposal is supported by scientific consensus that biogenic CO_2 should be regulated as being carbon neutral and is consistent with the RGGI Model Rule. We understand that at least one other commenter has raised the issue of how emissions from biomass are treated under the proposal. NAFO and VFA are sensitive to the issue of emissions of all kinds from biomass materials; however, these issues that are beyond the scope of the proposal. The proposal addresses CO_2 emissions from electric power generating units in Virginia, not other pollutants. Pollutants like benzene and formaldehyde are governed by other federal and state regulatory regimes already being administered in Virginia. The board should continue to focus the proposed regulation on CO_2 emissions and let existing laws and regulations govern non-CO_2 emissions from electric power generating units. We encourage the board to allow operators that co-fire biomass with fossil fuels to deduct the biogenic CO_2 emissions from the total CO_2 emissions the unit must cover with allowances. It is consistent with carbon-neutral environmental policy, and would bring Virginia in line with the RGGI Model Rule, as well as other RGGI states like New York. The Department of Forestry recognizes the sustainable development value and economic benefits of promoting use of biomass and biogenic fuel sources in Virginia, stating that the "benefit[s] of expanded utilization of biomass include: [p]rovid[ing] new markets for waste wood, manufacturing residues, and materials from forest management activities; … [r]educ[ing] material going to landfills, being dumped or open burned, such as woody debris and other wood waste; [r]educes site preparation costs for artificial regeneration; [r]educ[ing] pollution compared to using fossil fuels …." Congress also understands the environmental and sustainable development benefits of biomass-based fuel. In a display of bipartisan support, Congress passed the Consolidated Appropriations Act of 2018, where it directed the Department of Energy, the Department of Agriculture, and the Environmental Protection Agency to "establish clear and simple policies for the use of forest biomass as an energy solution, including policies that (A) reflect the carbon-neutrality of forest bioenergy and recognize biomass as a renewable energy source, provided the use of forest biomass for energy production does not cause conversion of forests to non-forest use; (B) encourage private investment throughout the forest	

	biomass supply chain … (C) encourage forest management to improve forest health; and (D) recognize State initiatives to produce and use forest biomass." Encouraging the biomass fuel market to grow in Virginia will continue to help the board achieve the purpose of the regulation: "to control CO_2 emissions in order to protect the public's health and welfare." As reported in The Economic Impact of Virginia's Agriculture and Forest Industries (2017), "Biomass energy production has emerged in recent years as a significant new market for surplus wood residues in Virginia. Federal clean and renewable energy programs and Virginia's voluntary Renewable Portfolio Standard offers incentives to the state's power companies to produce electricity from renewable resources. Woody biomass accounted for most of Virginia's renewable power generation in 2015 and approximately 5% of total power generation in the state. Since 2012, Virginia has added over 300 MW in electrical power generation capacity." Also, "Virginia hosts 10 wood pellet plants, most of which have been established in the last decade. Collectively, they processed over 1.4 million tons of wood, mill, and forest residues." NAFO and VFA can vouch that a broad range of robust markets for all Virginia wood and fiber are in the best interests of forest health and sustainability, the economic prosperity of the state, and the welfare of citizens of the state. Markets for low value wood that may not have other outlets are critical to woodland owners and to lumber manufacturers searching for purchasers of sawmill residues. Energy production from woody biomass aids in reducing the threat of wildfire and insect infestation, and can enhance wildlife diversity. It is vital to have markets for wood during the clean up of biomass debris resulting from natural disasters. By exempting biomass-only and near biomass-only facilities, the board has demonstrated that it agrees biogenic emissions are inherently different from fossil fuel carbon emissions. We urge the board to consistently apply these conclusions by allowing operators that co-fire biomass with other fuel sources to deduct their biogenic emissions when calculating compliance. This policy has already been developed in the RGGI Model Rule and in 6 of the 9 RGGI states. Virginia would be an outlier by disallowing biogenic CO_2 deductions. Since RGGI began, it has engaged working groups to develop Model Rules that can be reviewed, adapted, and implemented by states joining the system. Many stakeholders participate in these reviews and many states have chosen to adopt in full substantive provisions of the Model Rule. In every iteration of the Model Rule, RGGI has allowed operators that co-fire biomass with fossil fuels to deduct the emissions	

	attributable to biomass from the total amount of CO_2 emissions for compliance purposes. The RGGI Model Rule is not an abstract framework; most states that participate in RGGI have adopted it almost verbatim and implemented it with great success. The rule should allow operators co-firing biomass with fossil fuels to deduct biogenic emissions from annual CO_2 compliance accounting. It is consistent with the environmental and economic policies built into the regulation. NAFO and VFA encourage the board to add a definition of biomass. This will add clarity to the issue of biomass exemptions and allow the board to more easily review the exclusion of biogenic emission from CO_2 co-firing facilities. The legislature has already provided such a definition in VA Code § 10.1-1308.1.	
118. National Council for Air and Stream Improvement, Inc. (NCASI)	The rate at which global CO_2 emissions are increasing and the implications for global temperatures in the near- and long-term has led to calls for steep near-term reductions in emissions. IPCC indicates that, with respect to emissions of CO_2, it is cumulative emissions that will determine peak global temperature. IPCC notes that, "…taking into account the available information from multiple lines of evidence . . . the near linear relationship between cumulative CO_2 emissions and peak global mean temperature is well established in the literature and robust for cumulative total CO_2 emissions up to about 2000 petagrams of carbon. It is consistent with the relationship inferred from past cumulative CO_2 emissions and observed warming, is supported by process understanding of the carbon cycle and global energy balance, and emerges as a robust result from the entire hierarchy of models." IPCC indicates that, "A number of papers have found the global warming response to CO_2 emissions to be determined primarily by total cumulative emissions of CO_2 , irrespective of the timing of those emissions over a broad range of scenarios." One study cited by IPCC states that ". . . the relationship between cumulative emissions and peak warming is remarkably insensitive to the emission pathway (timing of emissions or peak emission rate). Hence policy targets based on limiting cumulative emissions of CO_2 are likely to be more robust to scientific uncertainty than emission-rate or concentration targets." It is only by reducing cumulative CO_2 emissions and thereby peak global temperature that ecological tipping points can be avoided. Near term increases in CO_2 that allow later reductions in cumulative CO_2 emissions are different from those that do not. In this context, it is not uncommon for increased use of forest bioenergy to result in near-term increases in atmospheric CO_2, compared to continued use of fossil fuels. However, as long as land remains in forest, increased use of forest bioenergy to displace fossil fuel accomplishes longer-term reductions	See comment 67 for further discussion of biomass.

	in cumulative CO_2 emissions. The time required for increased use of forest bioenergy to transition from net CO_2 emissions to net CO_2 reductions depends on a number of factors. In the case of certain residual materials, the transition is essentially immediate. In other cases, this transition requires more time. Increased use of forest bioenergy to displace fossil fuels is likely to result in net benefits to atmospheric CO_2 within a decade or two. After this transition is completed, the benefits of forest bioenergy continue to accrue. Even critics of forest bioenergy acknowledge the long-term benefits of displacing fossil fuel with forest bioenergy. A report prepared on behalf of the National Wildlife Federation and SELC, for instance, found that "…using southeastern forests for an expansion of electric power generation produced a significant long term atmospheric benefit, but at short term atmospheric cost." In the this study, a 35- to 50-year breakeven period was estimated, but this study did not account for reduced deforestation and increased afforestation associated with increased demand for wood, a well-documented phenomenon. Near-term increases in CO_2 emissions must be judged in the context of whether they are associated with reduced cumulative CO_2 emissions in the longer term. This is because of the insensitivity of global temperature to near-term CO_2 emissions, and the need to reduce cumulative CO_2 emissions to limit peak global temperature. These considerations are directly related to questions about biogenic CO_2 resulting from increased use of forest bioenergy. Increased use of forest bioenergy often results in higher near-term CO_2 emissions compared to continued use of fossil fuel but, as long as land remains in forest, cumulative CO_2 emissions are reduced in the longer term when fossil fuels are displaced by forest bioenergy. This phenomenon needs to be considered when contemplating potential regulation of biogenic CO_2 emissions from biomass energy production. The two cases in which emission profiles argue for differential treatment of biomass are 1) when the material used for fuel would have ended up being emitted to the atmosphere even if not used for energy production, and 2) when sustainable management of the biomass resource ensures that ongoing growth will remove equivalent quantities of CO_2 from the atmosphere. In the first case, the biomass emissions that would have occurred anyway will prevent fossil fuel emissions associated with producing the same amount of energy. In the second case, a sustainably managed resource grows biomass equal to or exceeding the amount of biomass harvested, ensuring that the resource is not a	

	net source of CO_2. In both cases, it is the characteristics of the biomass feedstock, not the characteristics of the power generation process or facility, that support treatment as carbon neutral. By exempting facilities using 90% or more biomass feedstock, the regulation implicitly acknowledges the environmental and atmospheric benefits of biomass compared to fossil fuels. The regulation takes an all or nothing approach: either all of a facility's emissions are exempt (if it uses 90% or more biomass fuel) or none of its emissions are exempt. This removes any incentive to use biomass as part of a fuel mixture in fossil-dominant plants. We have evaluated the carbon stock in trees on timberland across the U.S. South. Carbon stocks increased from 4.9 billion to 5.6 billion tons from 2005-16, an increase of 14.5% over a period with an average of 104 million tons of carbon removed annually during harvests. Even if all the biomass harvested from the forest during this time was immediately converted to CO_2 and emitted to the atmosphere (far from the actual situation), the fact that forest carbon stocks continue to increase is proof that biogenic CO_2 from biomass removed from the forest is more than offset by removals of CO_2 from the atmosphere by growing forests. In Virginia alone, tree carbon stocks on timberland rose from 503 million tons in 2005 to 589 million tons in 2016, a net increase of 17% while carbon removals from harvests were 7.4 million tons annually. In summary, when biomass from residuals or from sustainably managed forests replaces fossil fuels, there are climate change mitigation benefits. A large body of scientific evidence supports the environmental benefits of biomass energy, regardless of whether the biomass is combusted alone or as part of a biomass-fossil mix.	
119. Northern Virginia Electric Cooperative (NOVEC)	While NOVEC's power supply portfolio is predominantly natural gas-fired, NOVEC is keenly aware of its responsibility to provide renewable energy; as such, NOVEC's waste wood-fired biomass plant, landfill gas-fueled generation, and solar energy resources provide over 8% of NOVEC's system energy requirements. The definitions of "fossil fuel" and "fossil fuel-fired" are appropriate and should not be modified. Waste wood-fired, biomass-generating facilities should remain excluded. NOVEC owns and operates a 49.9 MW generating facility in Halifax County that is fueled exclusively by waste wood products that come predominantly from logging operations. This facility provides a winning solution to the management of wood waste products and the production and delivery of renewable energy to the	See comment 67 for further discussion of biomass.

	power grid. NOVEC's mission includes the provision of a low-cost, reliable, and environmentally sound energy supply. NOVEC built this facility in response to member requests for additional renewable energy in its resource mix. NOVEC located the facility in an area that was already active in logging woodlands to supply the construction, furniture, and paper industries. Doing so minimized the need to transport waste wood over long distances; a side benefit was an economic boost to local communities. NOVEC does not log for the plant's fuel. Instead, purchasers of high quality timber hire loggers to clear land and deliver the high quality round wood for lumber products. The remaining un-marketable wood, known as "slash," remains in the form of branches, limbs and stumps. The region that provides slash to NOVEC's facility produces more than 1 million tons of this waste product annually. Land owners typically want the slash removed, as leaving it in place reduces the amount of land available for growing the next generation of trees. Harvesting slash is superior to sending it to landfills, as the volume would fill up landfill capacity. While slash can be disposed of through uncontrolled burning, there is no control of SO_X, NO_X, particulates, or other emissions. The NOVEC biomass model is the best alternative to open burning or leaving slash in the forest. NOVEC purchases slash already chipped and delivered in truckloads. Small businesses create jobs associated with chipping activities and delivery of wood chips. The facility's air quality permit limits the amount of certain emissions that result from combustion of wood chips. The heat generated during uncontrolled burns is wasted. At the NOVEC facility the heat produced from the combustion is captured and converted to electric energy, reducing the amount of electricity needed from other power plants. Fly ash produced by the plant is used as a soil nutrient by nearby farmers. In summary, NOVEC's biomass power plant is a win for the environment, the local economy, and Virginia. As such, biomass should not be included in the definition of fossil fuels. NOVEC pays a forestry tax to the Department of Forestry that is used to fund the re-planting of trees throughout Virginia. The forestry tax can be viewed as a carbon tax that is already in place and paid by biomass plants. Young trees take in a higher amount of CO_2 compared to older trees for the same acreage. Combusting wood slash does not emit any carbon that is not already in the natural life cycle. Biomass plants in economically challenged areas provide jobs and investments as well as tax revenues for schools and other local government services. Unlike natural gas or coal, biomass fuel is produced close to the plants and the harvesting/chipping/delivery of slash is a	

	significant economic engine for the locality and region.	
120. Northern Virginia Electric Cooperative (NOVEC)	Resolution of the unresolved revenues allocation methodology should be directed to the SCC for development of an equitable distribution formula that includes all electric utility ratepayers across the state. Even though the Regulatory Advisory Panel was unable to reach a consensus on a distribution approach for the revenue, the RAP ranked the following allocation goals as the two most important: 1) protect electricity customers, and 2) promote cost-effectiveness. The rules in this area reference the December 4, 2017, presentation before the Joint Committee on Electric Utility Regulation; it stated that the "revenue received by CO_2 Budget Sources owned by regulated electric utilities flow to rate payers pursuant to SCC requirements." This statement failed to recognize that Virginia ratepayers served by utilities that do not own CO_2 Budget Sources but purchase power from the PJM wholesale power market (presumably the CO_2 Budget Source entities market for their power) would see their power prices increase as a result of these rules as currently envisioned but would be unable to mitigate the increases in power prices through an allocation of the auction revenue as would be available to a select group of Virginia ratepayers. Making this potential treatment of utilities and its customers that do not own CO_2 Budget Sources is arbitrary and capricious. Assigning the resolution of this matter to the SCC and tasking the SCC to finish the job of developing an equitable distribution formula that includes all ratepayers across the state can achieve both of the original objectives of the RAP.	DEQ appreciates the commenter's concerns, however, this issue is beyond the scope of the regulatory action and the authority to address it rests with the SCC.
121. Natural Resources Defense Council (NRDC)	Because of immediate and growing health and economic dangers, Virginia law clearly encompasses CO_2 in its definition of air pollution. Limiting and reducing carbon pollution would also achieve the board's charge to prevent harm to public health, safety and welfare. Because of the health and economic dangers that unmitigated carbon pollution poses to Virginia's human health, its economy, and property, we broadly support the proposed rule, using the same means already proven effective in 1 in 5 states in the country: a sensible, achievable limit on electric sector carbon pollution, with subsequent annual reductions. NRDC supports DEQ's proposal to ensure allowances comport with, and are fully tradable on, RGGI's pre-existing platform, due to its low administrative costs, third party market monitor reports, and robust cybersecurity. NRDC recommends that the rule set a 2020 baseline of 28.0 million tons. In order to determine the state's business-as-usual emissions and an appropriate annual reduction trajectory, DEQ should review reputable data and projections to establish a baseline that is not artificially high. To do so, DEQ should rely on up-to-date estimates of what Virginia's business-as-usual emissions	Support for the proposal is appreciated. The baseline has been set at 28 million tons, as discussed in the response to comment 37.

	will likely be in 2020. Similarly, DEQ should avoid industry-derived emissions projections that appear to be set unrealistically high, such as Dominion's 2017 IRP. DEQ's own proposal of either 33 or 34 million tons in 2020 is similarly flawed. An incorrectly high year-1 baseline budget would undermine the entirety of the program and jeopardize Virginia's ability to access the marked benefits of linking with the larger RGGI market. To set an appropriate baseline, DEQ should consider multiple up-to-date projections. The federal EIA's Annual Energy Outlook (AEO) from 2018 shows emissions decreasing in the Virginia-Carolina region by 27% between 2017-20. NRDC's IPM modeling, conducted by ICF, predicts similar emissions declines in Virginia between 2017-20. Preliminary results from NRDC's updated IPM modeling for Virginia (utilizing an updated 2018 data set) projects the state's power sector emissions to be 28.0 million tons in 2020. This more up-to-date modelling accurately reflects the reality of today's power sector in Virginia. Not only are additional coal retirements planned, but renewable energy installations are increasing, concurrent with recently lower or declining demand growth across the state in 2017. The factors of lower in-state electricity demand, persistently declining gas prices, and growing low-cost renewable energy resources mean the state's emissions will be well under 33 million tons in 2020. NRDC's IPM modeling supports the adoption of a 28 million ton baseline as a likely-to-occur starting point in 2020. A sufficiently ambitious program will drive significant economic and health benefits, including lower energy bills and rates, as well as improved public health resulting from cuts in co-pollutants like NO_X and SO_X.	
122. NRDC	DEQ must ensure the economic efficiency of the program by directing allowance value toward consumer benefit. Therefore, the proposal is correct to avoid imposing costs on Virginia families and businesses by awarding allowances directly to emitting generators for free. Doing so would allow the ultimate price of those allowances to be borne by Virginia families and businesses in the form of higher wholesale electricity costs, while providing a windfall profit to generators. NRDC therefore supports the consignment auction, as that mechanism provides an opportunity to recapture revenue that would otherwise be a windfall to generators. Indeed, these carbon allowances are inherently a public good, and thus their value must be captured and utilized on behalf of all Virginians. However, DEQ should amend the rule at 9VAC5-140-6215 to allocate allowances directly to distribution companies, based on pro rata share of load served, to ensure that allowance revenue goes directly to customer benefits. In order to ensure market efficiency and a transparent, undistorted allowance price that levels the playing field for all	The consignment auction is designed to be cost neutral, and RGGI employs various market control mechanisms to ensure a balanced and consistent flow of prices. In addition, Virginia is a regulated state; thus, it is the responsibility of the SCC to maximize economic efficiency for Virginia citizens. As discussed elsewhere, implementation and performance of the program will be continual, with RGGI program reviews and Virginia APA rule reviews providing opportunity for public comment should issues with program

	generators, achieve maximum economic efficiency for Virginia citizens through allowance allocation, and align with the Grid Transformation and Security Act of 2018, a standing Emissions Trading Stakeholder Advisory Group should also be established to monitor implementation and performance of the final rule.	implementation be identified.
123. NRDC	Many forms of biomass fuel are used or under consideration in Virginia, including landfill gas recovery, agricultural plant residues and animal wastes, forest harvest residues, energy crops, whole trees, and industrial waste. Many of these feedstocks can generate carbon benefits compared with fossil fuels, while others can have significant negative carbon impacts. We focus on "forest-derived" biomass, specifically, categories of forest-derived feedstocks used to produce electricity: 1) whole trees and other large diameter wood that would otherwise be used in merchantable end uses; 2) harvest residues that would otherwise be discarded or left to decay; and 3) industrial and mill waste produced at a forest products processing facility that would otherwise be burned. We support the proposal to require co-fired facilities to hold allowances for the CO_2 they emit, whether those emissions be from forest-derived biomass or fossil fuels. We urge Virginia to issue a final rule that covers the net carbon emissions from all utility sector biomass power facilities larger than 25 MW. Specifically, Virginia must account for the net emissions from forest-derived biomass combustion from power sector facilities greater than 25 MW, including both dedicated biomass-burning units and those that cofire with forest-derived biomass, and cover these facilities under the cap. We recommend that Virginia regulate net emissions from forest-derived biomass as follows: 1) CO_2 emissions from onsite waste that would otherwise be burned in an industrial setting without energy recovery will require zero allowances for each ton of carbon emitted; 2) CO_2 emissions from forest-derived residues that would otherwise decay will require approximately 0.69 allowances for each ton of carbon emitted; 3) CO_2 emissions from whole trees and large diameter materials that would otherwise have a merchantable end-use, including pulp, paper, fiberboard, engineered wood or lumber will require one allowance for each ton of carbon emitted. Virginia should also require EGUs to furnish to DEQ an estimate of the proportion of their total forest-derived feedstocks annually that fall into these categories. Finally, Virginia must reject sustainable forestry as a proxy for carbon impacts of forest-derived biomass. "Sustainability," however defined, is not a measure of carbon impacts.	See the response to comment 67 for a discussion of biomass.
124. NRDC	DEQ should design an economically efficient program with minimal market distortions, maximizing consumer	By linking to RGGI, Virginia will be linked to and

	benefits through efficiency investments by allocating allowances to distribution companies, and driving significant levels of in-state renewable energy development. Leakage can be minimized through the cost-effective development of untapped, clean resources like solar and energy efficiency. To ensure the program does not inadvertently lead to increased fossil-based electricity imports, DEQ should establish an annual program review process to assess whether interstate power flows are shifting as a result of the carbon price. A modest price on carbon is but one of many variables that can influence interstate power flows; any such analysis would need to account for those in a comprehensive manner. The RGGI states have already built in such emissions monitoring and reporting that assesses leakage, and we urge Virginia to do so as well.	involved in basic RGGI processes such as the routine program reviews and monitoring for potential leakage; however, recognizing the potential for any possible leakage to have an impact on disproportionately affected populations, a provision providing for review of impacts on such communities has been added. See the responses to comments 55 and 91 for further information.
125. NRDC	Climate change is inherently an environmental justice issue, as coastal communities and low-income communities ultimately bear the worst brunt of its impact. Therefore, the program should make significant cuts to CO_2 and ensure the consumer and energy efficiency benefits flow to the low-income citizens most impacted not just by climate change, but energy costs as well. Additionally, because CO_2 is not harmful in locally-higher concentrations, and there do not appear to be specific Virginia plants in proximity to at-risk communities whose capacity factors will increase under a carbon program, a carbon market in Virginia appears unlikely to create hot spots of pollution in frontline communities. And as the cap for carbon emissions is lowered, it can also create additional benefits of further reducing associated co-pollutants that cause health problems in communities close to their source. To ensure this is the case, the regular program review should also incorporate an annual environmental justice review. As RGGI demonstrates, it is good practice to build in regular program reviews to ensure the framework is working effectively. As Virginia adopts and implements its program, it may need to be adjusted over time, to ensure it is functioning efficiently and is driving significant and additional carbon pollution reductions. Program reviews can ensure that the cap is set and updated at the correct level to drive carbon emissions reductions beyond BAU, while maximizing the development of a clean energy economy. Virginia's program should undergo internal review on a regular basis, including stakeholder and public input as RGGI has done. The first review should occur in 2020, to review 2019 emissions and ensure the 2020 budget reflects the reality of Virginia's power sector emissions. As Virginia pursues linking with RGGI, it should integrate itself directly into that program's review processes.	As discussed in the responses to comments 55 and 91, Virginia will participate in RGGI program reviews, and a Virginia-specific program review will be conducted to ensure that EJ communities are monitored.
126. National Wildlife	We applaud Virginia's plan to confront the growing threat of climate change by creating a carbon market that can	Support for the proposal is appreciated, and the

Federation and the Virginia Conservation Network	link with RGGI. According to the National Climate Assessment, with 3 feet of sea level rise between 162 to 877 miles of roads could be inundated. Further, the gradual subsidence of coastal land in Virginia is magnifying the impacts of sea-level rise in the region. The rising seas threaten the coastal tourism industry in Virginia, a critical component of the state's economy. For examples, tourism contributed $1.4 billion to the economy of Virginia Beach in 2015, which resulted in $256 million in salaries and more than 12,900 jobs. Virginia's beaches and coastal waters also support 5 of the 7 sea turtle species found worldwide. Every year between 5,000-10,000 sea turtles swim into the Chesapeake Bay. Most of these turtles are the threatened species, which depend on the bay for food and safety. The loggerhead sea turtle depends on the bay's sandy beaches and dunes for nesting habitat. As the sea level rises and extreme weather events occur more frequently, these nesting habitats are being washed away. Likewise, the bay is also experiencing the impacts of rising sea levels and warmer water. Warming temperatures and increased runoff from flooding are making the bay and its tributaries susceptible to harmful algal blooms--a threat to people and wildlife. These changes alter the abundance and migration patterns of wildlife in the bay, leading to declines in waterfowl and commercially important shellfish. Virginia is home to the U.S.'s largest clam aquaculture industry, with an average annual economic impact of $60 million; the seafood industry in Maryland and Virginia support almost 34,000 jobs. RGGI is a highly successful cooperative effort to harness market forces to cap, price, and curb harmful carbon emissions that are contributing to the climate change threats facing Virginia. RGGI states account for one-sixth of the U.S. population and one-fifth of the nation's GDP. Since the program began, RGGI states have experienced a net gain in economic growth, increased jobs, long-run electricity cost reductions, and decreased emissions. By establishing a program to trade carbon that will link with RGGI, Virginia can enjoy the benefits of a carbon trading system while adding momentum to the effort to mitigate climate change by ensuring that, with California's carbon pricing system and New Jersey rejoining RGGI, 1 in 3 Americans will live in states with carbon pricing policy designed to drive down carbon pollution. Tackling carbon emissions is important for avoiding dangerous levels of warming that will have high costs for Virginia. Though there has been a downward national trend in emissions from the power sector in recent years, carbon pollution from Virginia's power plants has risen from 23 million tons in 2012 to 34 million tons in 2016	commenter's observations on the threat of climate change are recognized.

	and is expected to rise to 37 million tons in 2019. Linking to RGGI will reverse this trend for Virginia, propelling it to become a world leader in clean energy development, protecting the state's treasured natural resources and wildlife while creating new jobs and boosting the state's economy. While RGGI is considered to be an excellent example of a multistate program that encourages innovation and collaboration, there are still areas in which it can be improved. As an independent state linking with the RGGI carbon market, Virginia would have a unique opportunity to strengthen and advance the program. By doing so, Virginia has the potential to cement itself as a gold standard for carbon pricing.	
127. National Wildlife Federation, Virginia Conservation Network	Virginia could provide a model to improve RGGI's approach to biomass. While some biomass practices can reduce carbon emissions compared to other fuels, other practices increase near-term emissions and degrade wildlife habitat. One model for carbon accounting is the Net Emissions Impact, which applies multipliers for each unit of carbon from different biomass feedstocks. We urge Virginia to consider the nuances of biomass and weigh the potential for negative repercussions. The demand for low-value wood for pellets is driving a shift in the southeast from natural forests to pine plantations--a significant downgrade in habitat value. Unrestricted harvests leave high conservation value species and ecosystems vulnerable to biomass harvests, particularly wetland forests like bottomland hardwoods. Research has found that biomass from southeastern forests takes 35-50 years before it performs better than fossil fuels. This is far too long to mitigate the impacts of climate change, and not in line with he governor's executive order to reduce carbon pollution. We encourage measures to protect wildlife and habitat while pursuing measures to address climate. The state can reinforce the RPS limit on non-waste feedstocks by applying it to its carbon market as well. The state should preclude biomass sourced from high conservation value areas, and limit growth in the biomass market to truly sustainable feedstocks. Virginia must establish best practices for biomass production that lead to benefits for both wildlife and climate.	As discussed in the response to comment 67, and discussed in great detail elsewhere, there are pros and cons associated with using biomass as fuel. DEQ agrees that some biomass practices can reduce carbon emissions, and should include measures to protect wildlife and habitat.
128. Old Dominion Electric Cooperative (ODEC), Virginia, Maryland and Delaware Association of Electric Cooperatives	ODEC and the Association have significant concerns regarding the impact of this regulation on the electric bills of its ultimate consumers. Even a modest increase in bills in the territories served by ODEC and member cooperatives will be problematic, and larger increases in costs will turn electricity into a luxury item. The Cooperatives' service territories are predominantly rural and residential. The majority of rural areas in Virginia have seen both a declining population and sluggish to negative economic growth. The Cooperatives' service territories have high numbers of low- and middle-income families, families and seniors on fixed incomes, and	DEQ agrees with the commenter that costs to consumers are an important consideration, and has worked to develop a rule that minimizes costs while maximizing benefits associated with reducing carbon pollution. Implementing a cost neutral consignment auction is expected to minimize cost

	families suffering from unemployment and underemployment. The Cooperatives' service territories do not have significant non-residential loads--the service territories are over 80% residential. From 2011-15, many of Virginia's rural counties experienced negative job growth. Current Department of Labor Statistics show that many of the rural counties in Virginia have significantly higher unemployment rates than the urban and suburban areas of the state. Historically, most Cooperatives have per capita annual incomes that fall 22% below the statewide average. For Cooperatives that are more rural, that percentage is 260%, and for three of the most rural Cooperatives, the percentage is 30% or more below the statewide average. Historically, 13% of Cooperative member-owners are over 65 years of age, and unemployment in Cooperative territories is generally 1-4.5 percentage points above statewide unemployment rates. Based upon the 2010 Census, median household income in rural areas is less than half that of the suburban counties. Concerns over increased costs to consumers are not simply based on future projections. EIA Power Monthly indicates that there is already price pressure indicated on electric rates in RGGI participating states. Every state that participates in RGGI had average retail rates higher than the national average and 4 out of 5 of the states with the highest average retail rates in the U.S. participate in RGGI. The Cooperatives have only their ratepayers from which to recover costs; there are no separate stockholders. Furthermore, electric distribution cooperatives receive their generated electricity by contract. These contracts directly pass on the costs of any regulatory or environmental compliance to the distribution cooperatives, which then recover that cost from their consumers through a cost recovery mechanism in electric rates. Smaller cooperatives, including those wholly dependent on investor-owned utilities for their electricity, could be hit especially hard, as the costs of the regulation could be passed directly to those cooperatives and their consumers, with no mechanism for those suppliers to pass through proceeds from any sales of allowances back to the distribution cooperatives or their consumers.	impacts to consumers. To the extent that power is purchased from a regulated entity in Virginia, costs will be controlled through the auction and subject to SCC oversight.
129. ODEC et al.	There is no modeling that can show the projected local benefits based upon the anticipated program reductions. The modeling for economic impact of this type of regulatory effort can be severely compromised based upon a variety of unknowable factors: market assumptions, regional power flows, projected resource mix, and demand considerations. In this case, there has been very little analysis done to support the anticipated and likely impacts on electric rates. The limited modeling that has been done could be significantly understating the impacts of the regulation, and by the time we see the	DEQ understands that impacts on electric rates are important, and several cost/benefit analyses were conducted; see response to comment 61 for more information. No significant impacts to consumers are anticipated.

	results, it will be too late to make adjustments. We recommend a more holistic analysis be performed encompassing total energy consumption. Potentially higher future electric costs may produce unintended consequences in the form of shifts in energy usage or choice of fuel. An example would be a homeowner having an efficient electric heat pump choosing to produce some of the heat for their home via natural gas, propane, oil, or woodstove. In addition to the potential for additional emissions from these other alternate energy sources, one would also see increased CO_2 emissions from the delivery/transportation of these sources.	
130. ODEC et al.	Regulating CO_2 at the state level is not as effective as a broader regional or national approach. Putting this additional burden on Virginia generation will encourage imports from other states, potentially requiring the construction of additional transmission infrastructure to maintain reliability. This is already occurring where the RGGI regulation in Maryland has contributed to the construction of new transmission lines to facilitate the import of power from adjoining non-RGGI states. PJM, as a regional transmission organization, allows for cost-effective exchange of electricity throughout its territory, which includes the majority of Virginia. Inconsistent state CO_2 policies within PJM create distortions in generation dispatch that can increase regional emissions. For example, the cost of CO_2 allowances from the RGGI program in one state can discourage a low-emitting in-state natural gas plant from operating, only to make way for imported coal power from a neighboring state because the out-of-state plants do not incur CO_2 cost. We recommend adding a provision for an analysis of trends in imports in Virginia once the program has been implemented. If there is a significant increase in imports, Virginia should be able to adjust the regulatory requirements for in-state generators to deter the import of out of state generation. The board should consider "safety valve" measures--for consumer protection from price increases, for reliability of the electricity system, and for imports from out-of-state. The additional burden of this program could result in premature retirement of coal facilities, such as the Clover Power Station. These plants were designed, built and permitted in compliance with federal and state regulations to meet long-term electricity needs. This regulation may reduce the remaining useful life of these assets which are still being paid for by our consumers. Virginia needs to develop a mechanism to compensate consumer-funded prematurely-retiring coal generation. One possible way would be to carve out allocations for retired consumer-funded generation for a significant number of years after their retirement. This would remove a barrier to the closure of consumer-funded coal generation by providing allocated allowance revenue to	Virginia's program is not at a purely state level; rather, Virginia is linking to a larger group of states in order to leverage its carbon control abilities to the maximum. As discussed elsewhere, leakage will be monitored for and addressed as needed; see, for example, the response to comment 91. If the cost of allowances become too high the CCR is triggered; see comment 136 for more information. DEQ agrees that existing coal plants were designed, built and permitted in compliance with federal and state regulations to meet long-term electricity needs. Most of Virginia's coal fleet is owned and operated by Dominion Energy, which has the ability to adjust its electric generating portfolio to meet its business needs while protecting its customers' interests. See the response to comment 67 for additional discussion of biomass.

	offset the stranded costs. Other mechanisms would likely require legislation to implement. Those renewable generation resources owned directly by Cooperatives should continue to be counted as renewable resources and excluded from the proposed regulation. This includes not only solar PV projects, but also the NOVEC wood waste biomass plant in Halifax County.	
131. ODEC et al.	While it is true that some form of consignment auction has been used for other allowance programs, it is a wholly new concept to "link" Virginia to RGGI. We do not believe that the mechanisms that will have to be put in place to track allowances, as well as the increased burden on DEQ, have been fully factored into the cost of the program. Additionally, administrative costs have not been fully analyzed. Given that Virginia is not joining RGGI, but "linking" to it, we are unsure how administration of the consignment would be paid for. DEQ has no mechanism to recover its own administrative costs. As a not-for-profit cooperative, ODEC is exempt from federal income taxes as long as it receives no more than 15% of its revenue from non-members. This rule applies to all of the electric distribution cooperatives in Virginia. Cooperatively-organized businesses are designed, from their foundation, to serve their members, who are also their customers. Therefore, ODEC has concerns about the potential accounting and tax impacts of receiving "revenue" in the form of proceeds from the RGGI auctions. This concern would apply to any cooperatively-organized entity receiving auction proceed revenues. To the extent that the regulation maintains the concept of a consignment auction, consideration should be given to this unintended consequence. A solution could be to allow cooperatives to offset any allowance requirement with an equal amount of allocated allowances without the requirement to auction the allowances.	The consignment auction is designed to be cost neutral. This approach has been carefully crafted to minimize costs. Program design elements such as the unlimited banking of allowances may mitigate this issue further.
132. ODEC et al.	Virginia has seen a downward trend in energy consumption and CO_2 emissions. Virginia's energy resource mix is evolving, with more investments in clean energy resources and renewables, regardless of CO_2 regulation. As reported in January 2018, Virginia has reduced its overall CO_2 emissions from all energy-related sources from 123.1 million tons in 2000 to 103.0 million tons in 2015. That 16.3% reduction ranks Virginia as the 16th highest reduction among all states and significantly higher than the national average reduction of 10.3%. This includes all energy related sources of CO_2 emissions including utility generation, transportation, industrial, commercial and residential sources. Even more impressive is the reduction in average CO_2 emissions per person where Virginia reduced its average emissions per person by 28.9%, ranking it the ninth highest reduction in the nation and significantly better than the national average reduction of 21.1%. The	The commenter correctly asserts that investments in clean energy resources and renewables are increasing. The 28 million ton cap, as discussed in the response to comment 37, was selected. The RGGI program already contains multiple "safety valves"; the program is continually monitored and adjusted in order to protect reliability and resilience. See also the response to comment 33 for a discussion of modeling and emissions.

	current trends support the initial budget being set at 34 million tons. While the trend has been declining over the years, there has been a great deal of recent investment in new clean combined cycle generation that would be subject to the program. Virginia should be allowed to enter the RGGI program with a budget that is fair to Virginia given the current generation resources. Even with the budget set at 34 million tons, with the new generation assets, the goal will still be challenging. Given that Virginia generators are just now entering the RGGI-linked program, the banking adjustments that have been calculated by RGGI and are being proposed to be applied to subsequent years, should not be applied to the Virginia budget. These banking adjustments are based on participants outside of Virginia banking more allowances than anticipated, and not the actions of any generators in Virginia. Such an adjustment should only be applied to existing RGGI participants. In addition, there should be a reliability and resiliency safety valve. Such a mechanism would recognize that overreliance on intermittent generation or a single fuel such as natural gas may negatively impact reliability and resilience. Analyses should be performed to assure that resiliency is maintained and that critical generation resources are not retired because of the regulation. In the case where retirement of critical resources is likely, adjustments to the allowance allocations should be contemplated.	
133. ODEC et al.	We generally support the provision establishing that 95% of the budget will be allocated to the generators. Particularly for the Cooperatives, revenues from the allocations will go directly to consumers. This is a critical means to reduce the net cost impact on electric consumers. Setting a price on CO_2 emissions as this program does is enough incentive for all sectors to seek ways to reduce emissions. Even when allocated allowances, utilities will still have an incentive to pursue low or non-emitting resources and energy efficiency measures. Not having allowances granted to such sources and forcing electric ratepayers to foot the bill for CO_2 emissions would be a significant cost impact and can be somewhat mitigated by allocated allowances to generators as proposed. Any utility with a wholesale power contract could be adversely affected by a system where their consumers pay for the costs of CO_2 emissions and receive nothing in return. This could be resolved by flowing auction revenues through applicable FERC ratemaking mechanisms using FERC Form 1 data.	Revenues will only be realized if there are excess allowances. It is beyond the scope of this regulation and the department's authority to direct auction revenues through FERC.
134. ODEC et al.	We recommend allocation based on emissions, not megawatts generated. Incumbent utilities have made significant investments under the existing regulatory compact to provide power economically and reliably to meet retail loads. There should be an appreciation for	See comment 136 for a discussion of allocations.

	the value associated with these investments in electric generating plants. The conditional allocations being allocated on an emissions basis will provide a glide path for the existing resources to continue to operate within their remaining useful life, rather than having significant stranded resources. Coal generators would still have an incentive to operate efficiently since the allowance price will set the value of each ton of CO_2 emitted irrespective of who is given the allowances.	
135. Partnership for Policy Integrity (PFPI), Appalachian Mountain Club, Center for Biological Diversity, Dogwood Alliance, Michelle's Earth Foundation	We analyzed Energy Information Administration (EIA) 2016 data on the fuels burned and energy generated from Virginia's power sector and calculated CO_2 emissions using EIA emissions factors for each fuel. To achieve effective carbon reductions, and to administer the program fairly, Virginia should cover all plants greater than 25 MW, including industrial facilities that generate heat and power, standalone bioenergy plants and waste-to-energy plants in the utility sector. This would reduce CO_2 emissions more effectively, remove incentives to re-fire fossil plants with biomass, and reduce air pollution at some of the most polluting plants in Virginia. Industrial power plants are a significant source of CO_2 in Virginia. As a whole, the industrial sector emitted 16% of power sector CO_2 in 2016. The proposal would exclude some of the biggest polluters in Virginia. For instance, the WestRock Covington plant would under the industrial exemption as a plant that generates on-site heat and power. This facility burns natural gas, bituminous coal, distillate fuel oil, residual fuel oil, black liquor, and wood, and was responsible for 7% of Virginia's power sector CO_2 emissions in 2016. The company brought a new 75 MW wood-fueled generator online in 2013, which led to a dramatic increase in wood consumption and emissions. The facility is a large source of conventional pollution, and has recently been penalized by EPA for excessive particulate matter emissions. Similarly, the WestRock West Point mill burns coal, black liquor, distillate fuel oil, natural gas, residual fuel oil, sludge waste, and wood solids. It was responsible for 3.3% of the state's CO_2 emissions but as an industrial burner would be exempt, as would be the International Paper Franklin mill, which emitted about 700,000 tons of CO_2 from black liquor and natural gas in 2016. Failure to cover dedicated biomass-fueled power plants will exempt a significant amount of CO_2 pollution from coverage, and, like the industrial exemption, give a free pass to some of the largest sources of air pollution. The 50 MW Halifax County plant is a standalone facility shown as burning less than 300,000 tons of wood in 2016 although its capacity is upward of 600,000 tons. The plant has recently been subject to consent decrees for air quality violations. Dominion operates the 83 MW Pittsylvania station, and recently converted 3 coal plants	See the response to comment 65 for a discussion of industrial facilities, and the response to comment 67 for a discussion of biomass. The regulation has been amended in order to address CHPs with more clarity; see the response to comment 74.

	to burn biomass at Altavista, Hopewell, and Southampton, for a total of about 153 MW. Their combined permitted emissions annually were 253.2 tpy $PM_{2.5}$, 114.6 tpy SO_2, 1,237 tpy NO_X, 2,748 tpy CO_2e, and 129.4 tpy VOC. Dominion also built the 585 MW Virginia City plant to burn up to 20% wood with 80% fossil fuels; this facility would need to purchase allowances for biomass-derived CO_2 under the plan. The plan also apparently exempts plants that generate electricity by burning municipal waste, a portion of which is considered biogenic. Combined, biomass burned in Virginia facilities emitted over 8 million tons of CO_2 in 2016; the non-biogenic portion of municipal waste emitted another 1 million tons. However, under the Virginia plan, only about 2.5% of this CO_2 would be regulated under the cap--the approximately 230,000 tons emitted by co-firing biomass at Virginia City. Covering biomass will dramatically increase the plan's effectiveness because it will regulate a large source of CO_2, and remove an incentive for fossil-fired plants to use biomass. Burning biomass undermines efforts to reduce emissions because biomass fuels inherently emit a large amount of CO_2 per unit energy. In 2016, the top 3 highest-emitting categories of solid fuel per unit energy were biomass. When fuels are burned in a power plant, the efficiency of conversion of fuel to energy affects the CO_2 emission rate on an output basis. Wood-burning power plants are inefficient, in part because wood tends to have a high moisture content. This further increases the GHG impact of bioenergy. We also support including emissions from co-fired biomass. The high moisture content of biomass co-fired with fossil fuels can decrease the efficiency of the facility overall, meaning that it emits more CO_2 per unit energy. In comments to DEQ, Dominion claimed the following: "In 2013, Dominion made significant investments to converted three 51 MW units that used coal to 100% biomass, encouraged by EPA's prior determination that biomass was carbon neutral for PSD permitting. Close proximity to an ample supply of waste wood biomass as well as EPA's carbon-neutral policy for permitting under the PSD effective at that time were key economic drivers for these projects. Given Dominion's significant investment in renewable wood waste and forest residuals biomass, it is important for our customers that biomass emissions be considered carbon neutral." This statement highlights how treating bioenergy as having zero emissions is an incentive for more tree-burning power plants. Beyond that, it contains several inaccuracies. Dominion did not convert three "51 MW units that used coal." The units were 63 MW and the boiler de-rating that occurred with the conversion to biomass downgraded the units to 51 MW. It is not true	

	that EPA had made a "prior determination that biomass was carbon neutral" when the Dominion plants were permitted. When EPA began regulating power plant CO_2 under PSD permitting in early 2011, biomass power plants were regulated alongside fossil fueled power plants--all the CO_2 was counted. In July 2011, EPA suspended regulation of CO_2 from bioenergy facilities under PSD for 3 years and convened a panel of its Science Advisory Board to advise the agency on how to regulate biogenic CO_2. EPA had not determined that bioenergy was carbon neutral--it admitted the topic required study, while suspending regulation. The suspension was challenged, and in 2013 EPA's regulatory deferral for biogenic CO_2 was vacated . The court identified nothing in the Clean Air Act that would allow EPA to exempt biogenic CO_2 from being counted when determining whether a facility meets the emissions thresholds that trigger PSD permitting. The permit for Dominion's first conversion (Altavista) is dated May 2012--prior to the ruling but concurrent with the court case. Dominion knew that EPA had not concluded that bioenergy was carbon neutral and knew there was a possibility that plants would be regulated in the future. Further confirming that Dominion knew the status of bioenergy GHG permitting was indeterminate, the company submitted comments to the Science Advisory Panel requesting that the panel make an a priori determination that biomass is carbon neutral. The issue was still in play in 2014, when EPA published an NSPS for GHG emissions. The NSPS both acknowledges the importance of feedstocks for net carbon impacts and conclusion of the panel that biomass cannot be considered carbon neutral. A 2013 article by a Dominion employee mentions several reasons for the coal plant conversions, stating "Benefits to the environment would include reductions in nitrogen oxides, sulfur dioxide, particulate matter and mercury"--but nowhere mentions a reduction in CO_2 emissions as a rationale. Perhaps this particular executive was aware of the skepticism that met Dominion's claims about bioenergy at the SCC when the company applied to convert the plants. In its application and 2011 testimony, Dominion made numerous claims regarding biopower. Dominion described that residues would decompose in 10-15 years, or 25 years for large logs, and that burning these residues should be considered carbon neutral. While this argument might be valid if Dominion's converted coal plants operated for a single year and then shut down, for facilities in continuous operation, the net cumulative atmospheric CO_2 loading over this period would be many millions of tons more than if the residues had simply decomposed.	

	Dominion and other bioenergy proponents also argue that as long as forest growth exceeds harvesting, that burning wood should be considered as having zero emissions. When forests are cut and burned for electricity or heat, the forest bank's deposits are smaller than they would have been if the trees had been left standing, and there is more CO_2 in the atmosphere. When the bioenergy industry claims that current forest growth should be considered as offsetting bioenergy emissions, the bioenergy industry is effectively arguing that the bank's deposits can be transferred from one customer's account to another to cover up for the fact that some customers have withdrawn their money. This violates the concept that mass must be conserved. As the IPCC states, "If bioenergy production is to generate a net reduction in emissions, it must do so by offsetting those emissions through increased net carbon uptake of biota and soils." The biomass industry argues that the IPCC treats bioenergy as carbon neutral. The IPCC GHG reporting protocols count carbon loss from bioenergy in the land-use sector, when trees are harvested, and thus to avoid double-counting, does not count it in the energy sector--not the same as treating it as having zero emissions. The false representation of this position has become so pervasive that the IPCC has stated, "The IPCC approach of not including bioenergy emissions in the Energy Sector total should not be interpreted as a conclusion about the sustainability or carbon neutrality of bioenergy." DEQ's decision to count biomass emissions from co-firing should be extended to cover emissions from utility sector and industrial sector bioenergy emissions. Adding these plants would require raising the cap but should not entail other difficulties; the plants would simply increase the number of units covered, and should not interfere with the program's ability to interface with RGGI. Policy precedents for counting biomass carbon exist elsewhere. Massachusetts ended renewable energy subsidies for utility-scale wood-burning power plants in 2012, and the District of Columbia enacted a similar law in 2015. Treatment of bioenergy as having zero emissions under the E.U.'s carbon trading program has led to explosive growth of the wood pellet industry in the U.S. southeast, including Virginia. Forests, including areas that represent some of the most carbon-rich and biodiverse ecosystems in the U.S., are being clear-cut for biomass fuel. DEQ has gone part of the way toward regulating bioenergy emissions by proposing that co-fired facilities be required to hold allowances for 100% of the CO_2 they emit, whether it be from biomass or fossil fuels. We appreciate that DEQ has not repeated the mistakes of the RGGI	

	program in allowing "eligible" biomass to be treated as having zero emissions when it is co-fired in electric plants and defining eligible biomass as sustainably harvested wood. "Sustainably harvested" is a largely undefined term and is not meaningful for carbon accounting. However, it is important for DEQ to cover all plants under the cap, including those that primarily or exclusively burn biomass. This might be facilitated by counting bioenergy net emissions under the carbon plan rather than stack emissions. Net emissions are a cumulative measure assessed over some time period, and represent the difference between stack emissions and emissions if the biomass underwent some alternative fate. Four categories of wood-derived biomass are defined by the alternative fate if the material is not burned in a power plant: trees that would continue growing or be harvested for another purpose; residues that would remain onsite to decompose or be burned; residues that would be incinerated; and residues that can be used for other purposes like mulch or particle board. This framework matches in part Dominion's argument about forestry residues that "Unless re-purposed for other uses, such as energy production, this material is often left on-site after a harvesting operation is completed and will eventually be burned on-site or nearby, or will decompose, releasing carbon into the atmosphere and turned into organic matter on the forest floor and soil." Emissions from burning residues for energy are significantly greater than those from decomposition over decades, and thus net emissions should be regulated. The NEI at year 10 is 70%, meaning that 70% of the direct stack emissions represent a net increase of CO_2 over that time period. Applying this figure to carbon trading would mean that facilities burning forestry residues would be obligated to purchase 0.7 allowances for every ton of CO_2 they emitted. For facilities burning materials where the alternative fate was incineration, the net difference between direct emissions and alternative fate emissions is zero. Since many industrial facilities burn residues that may be incinerated if not burned for energy, this provides an exemption based on a scientific rationale rather than an arbitrary exemption. We support counting CO_2 emissions at the stack as the best way to account for CO_2 emissions from industrial, waste-to-energy, and biomass facilities. Counting stack emissions is a closer approximation of the net atmospheric impact than the assumption that emissions are zero, which is the outcome of not regulating wood-burning power plants. Stack emissions are an underestimate of the actual net carbon impact of cutting and burning whole trees that would have otherwise continued growing and removing CO_2 from the	

	atmosphere. As a secondary option, we support the NEI methodology because it is relatively simple, science-based, and would ensure that some emissions are counted even if companies claim to use residues and in fact use whole trees. It would also exempt facilities that burn materials where the alternative fate is genuinely incineration. Regulating these facilities is important because they can be large sources of CO_2, and need the same incentives as the rest of the power sector to reduce emissions. CHP plants contributed 22% of Virginia's power sector CO_2 in 2016, and electric-only plants emitted 78%. Most CHP plants are in the industrial sector; those not designated as industrial include Hopewell Cogeneration; Spruance Genco, a coal-burner; and Dominion's Southampton biomass power station, which reported a total heat input of 25% greater than its heat input for electricity only. This plant received 4% of its heat input from distillate fuel oil in 2016. DEQ will need to find a way to accommodate cogeneration plants outside the industrial sector even if the industrial exemption is maintained. However, we recognize DEQ not wanting to overregulate CHP if it leads to reductions in fuel burning. To incentivize CHP, DEQ should cover CHP plants, but provide a reduction in allowance obligations based on generation of useful thermal energy. It is not advisable to simply exempt CHP plants. Some plants may claim to operate as CHP plants, but not generate a meaningful amount of useful thermal energy. Many industrial sector CHP plants burn a variety of dirty and inefficient fuels. Subjecting these plants to trading will ensure that they seek to minimize emissions and generate energy from zero-emissions technologies.	
136. Resources for the Future	The regulation will distribute most of its allowances to compliance entities without charge. However, the allowances have conditional value that cannot be realized and the allowances cannot be used for compliance until they have been submitted on consignment to auction for sale. The state proposes to link with RGGI and the consignment to auction would be integrated as part of the RGGI auction. The compliance auction is a good option for Virginia if the state decides that it cannot directly auction allowances. Under the compliance auction, Virginia compliance entities that were the original holders of the conditional allowances will receive the auction value of their consigned allowances, once sold, in proportion to their original allowance shares. Those entities can purchase the allowances they need for compliance in the auction or in the secondary market. Virginia's consignment auction is not unique. Previous experience with consignment in emissions markets include the SO_2 trading program established under the	The commenter's observations are appreciated. DEQ agrees that the updating output based allocation approach will effectively control CO_2 emissions while being cost-effective and transparent.

	1990 Clean Air Act. In that program the emissions allowances were initially distributed without charge to compliance entities, but those entities were required to submit a fraction of their allocation under consignment to an auction held by EPA. In retrospect, economists describe that consignment auction as an important element of the overall program's marked success. Currently, the Western Climate Initiative runs an auction that is very similar in its basic design to the RGGI auction. In that auction, allowances that have been initially distributed to investor-owned utilities in California must be consigned for sale in the auction, with the revenue returned to the utilities on a proportional basis. The California auction also has a price floor and a cost containment reserve, and the program has worked without a problem. The consignment approach should integrate seamlessly with the existing auction in which allowances are submitted for sale by the RGGI states. The auction outcome does not depend on whether the sold allowances are submitted by a state or if they are submitted by a compliance entity through consignment. From the perspective of other buyers and sellers including the other RGGI states, the auction works equally well in either case. Consigned allowances from compliance entities in Virginia will also work seamlessly with other features of the RGGI program. The consignment auction approach is a valuable feature because it enables the price floor, the ECR, and the CCR to function seamlessly with respect to the aggregate supply of allowances, including both the consigned and state-held allowances. The consigned allowances will be indistinguishable from state-held allowances in the auction, and these auction mechanisms will affect all the allowances in the same way. The same price floor and price points for the ECR and the CCR can apply to the consigned and state-held allowances in like fashion. The consignment approach is transparent, in that all observers can witness the original holders of the allowances, as well as the flow of revenues back to the original allowance holders. This transparency has value to Virginia regulators and it enables evaluation of market performance that is regularly conducted by the RGGI market monitor. Moreover, the consignment approach creates a program design that could seamlessly segue to a revenue raising auction if the state were to choose to move in that direction. The regulation describes a CO_2 allocation methodology to distribute allowances among compliance units based on their share of total electrical output across all units that are eligible to receive an allocation. This "updating	

	output based allocation" approach has been used in previous emissions trading programs including by some of the states in the NO_X Budget Program. This approach provides an ongoing incentive to reduce the emissions intensity of electricity generation. In this regard, it is far superior to an approach that would distribute the emissions allowances across compliance entities based on a static, historic measure of emissions or heat input. The proposal aligns incentives associated with the award of allowances with overall program goals and can be expected to improve program's cost effectiveness. An important motivation for using updating output based allocation is that it provides a production incentive, because the greater the production at a facility the greater the share of the emissions budget that would be awarded to that facility. Detailed simulation modeling at Resources for the Future has shown that this approach to allocation can mitigate potential leakage of electricity generation from the state. Because updating output based allocation provides an incentive to increase generation, it helps to mitigate leakage. Consequently, this choice of allocation method helps protect economic interests in the state while helping to achieve environmental goals. It also works well with the consignment auction. Under free allocation with a consignment auction, the Virginia compliance entities that were the original holders of the conditional allowances will receive the auction value of their consigned allowances, once sold, in proportion to their original allowance shares. Because most compliance entities are owned by companies regulated by the state, the value of the consigned allowances would contribute to meeting the revenue needs and thereby benefit electricity consumers. To strengthen this relationship between the source of revenues and their use, the state might require that some portion of the allowance value be invested in program-related efforts such as energy efficiency or renewable energy. In Virginia, the value of consigned allowances returns to regulated companies, and because of state regulatory oversight that value is expected to accrue to the benefit of rate payers. This outcome is somewhat similar to the practice in some other RGGI states such as Maryland, where a portion of allowance value has been returned on the electricity bill. In the future, if the program were to become substantially more stringent either as a regional program or as a model for a national program, the return to rate payers would be more substantial. However, if the value reduces the consumer's monthly electricity bill, then from the perspective on consumers, their cost of electricity would appear to not reflect the carbon price. In	

	turn, this would deny consumers the information they need to make decisions about energy-efficient investments in household appliances and in their regular electricity consumption. As a result, the regulation may have minimal effect on overall electricity demand. An alternative to returning the value of consigned allowances to the rate base and thereby reducing monthly consumer bills would be to return the value to electricity consumers on an equal and periodic (i.e., six month) per-customer-account basis. Consumers would see higher prices in most months, reflecting the value of allowances, thereby providing an incentive to conserve energy. Periodically, they would receive a dividend that preserves distributional goals and provides a program feature that is likely to be popular with recipients, which in turn builds constituent support for the program. The consignment auction preserves many of the benefits of a direct auction of allowances; however, a direct auction has further advantages. A revenue-raising auction would provide state agencies with financial resources to make investments in carbon mitigation, to address distributional goals, or to address the consequences of a changing climate. Public finance economists suggest that in the long-run, great value is associated with a tax swap, with revenues from the carbon price used to reduce other taxes in the state and thereby to help attract economic activity to the state. Another option would be to use revenues to provide dividends that directly compensate households as the common property owners of the atmosphere. The state of Virginia should consider an approach that would directly auction allowances to raise revenue to address these pressing needs to address the challenge of climate change. Two important elements of the RGGI program are provisions to contain emissions and costs when changes in electricity markets lead to outcomes that are unanticipated. The ECR constrains the quantity of allowances that would be sold in the auction when the auction price falls below a specific level. At an even lower price level, the price floor provides an absolute minimum price for the sale of allowances. As a complement, the CCR makes allowances available in addition to the intended cap if the auction price rises to a specific level. Together, these features make the supply schedule for emissions allowances responsive to the equilibrium price in the auction, which is a characteristic of commodity markets in general, but rare in environmental markets. Among other effects, this design helps to reduce price volatility in the allowance market. Empirically, the more important of these provisions is the ECR (and the price floor) because experience in	

	emissions markets around the world shows a consistent tendency for prices to fall below expected levels. The ECR automatically restricts the supply of allowances if the cost of emissions reductions falls, and the CCR automatically expands supply if the cost increases. This feature helps boost confidence in the allowance market and reinforces the goals of the trading program in a transparent way by reducing emissions automatically when it is unexpectedly inexpensive to do so. The RGGI auction has a bid limitation that limits the share of allowances that any one entity can purchase to 25% of all allowances that are sold. This bid limitation is a feature to guard against potential manipulation of the auction or the allowance market. When Virginia links to the RGGI program, the bid limitation in the auction might not make it possible for all the Virginia compliance entities to rely strictly on the auction to acquire their necessary allowances if they chose to do so. Virginia should work with RGGI to amend this rule by expanding the size of the bid limitation such that every entity has the possibility of relying on the auction for compliance. A change from 25% to 30% should be adequate. That change would be modest, and will not create a meaningful possibility for market manipulation, because still, no single entity would constitute a sufficient share of demand in the auction to exercise strategic behavior. Further, the largest compliance entities in Virginia operate under cost-of-service regulation, unlike many other firms in the RGGI market that are IPPs. A regulated company would not have the same potential incentive for possible manipulation as would competitive companies because advantageous rewards would be expected to flow to rate payers rather than shareholders; this may lessen the incentive for strategic behavior and mollify potential concern. Nonetheless, the RGGI market monitor should remain vigilant about market disruptions due to manipulation or strategic behavior; however, the concentration in the market held by the largest entity after Virginia begins to participate in RGGI is not sufficient to increase that concern and the expanded size of the market overall should reduce concern. Given that Virginia's regulatory design is very complementary to the RGGI program, the only substantial issue is the relative emissions budgets of Virginia and RGGI when Virginia enters the program. Virginia and the RGGI states will want to look for the right balance among costs incurred by all the states. One of the reasons why the states conduct modeling is to anticipate this type of issue and plan for eventualities. Virginia and RGGI's actions model this and address forecasted emissions is the right process to provide analysis that can support decisions that enable the reduction of emissions on a broad regional basis.	

	However, the assumptions in the modeling will directly influence the results and it appears that the scenarios that were modeled took a very cautious approach, meaning that they lead to forecasts for emissions that are greater than are likely to occur. On a national basis, the demand for electricity fell during the Great Recession but it has remained nearly level since then, reflecting a decreasing energy intensity of economic activity. In Virginia, demand has fallen and subsequently risen, where most of that rise has been associated with large data storage facilities. That increase is more than adequately represented in even the most modest forecast of demand growth by DEQ. A second factor is the emissions intensity of electricity generation in the state. Over recent years there has been a substantial growth in natural gas generation that has a lower emissions rate than coal. Much of the new natural gas has reduced imported power, but it has also reduced the use of coal for electricity generation in the state and that trend is expected to continue, and to result in the retirement of coal-fired capacity over the next few years. At the same time, a substantial growth in renewable energy resources is anticipated. Indeed, some of the companies associated with the recent growth in electricity demand for data storage are advocates of renewable energy and have pledges to their customers to link their consumption to expanded renewable generation. In summary, these secular changes appear to indicate that the state of Virginia is on a pathway that will see declining emissions soon. At present, Virginia is considering annual base budgets of either 33 or 34 million tons per year. The considerations I discuss point to the 33 million ton value for the base emissions budget; although a compelling case could be made that the budget could be lower still. Use of a consignment auction coupled with updating output based allocation for the initial distribution of emissions allowances is a strong design for the trading program. The value of allowances submitted to the consignment auction is expected to flow to the benefit of ratepayers, but as that value increases the state should consider separating the value from monthly electricity bills and return it to customers on an intermittent basis. There are additional benefits from directly auctioning allowances that could help the state address a variety of climate-related goals, and this should be considered also. An especially important feature of the RGGI program design is the ECR, which Virginia should support. There is a provision in the RGGI auction design that limits the bid quantity by a compliance entity; this provision could be inconvenient for RGGI and should be	

	considered further in collaboration with RGGI. Finally, the lower of the two emissions budgets is more appropriate given current trends in the industry in Virginia, and an even lower budget could be justified.	
137. Regional Greenhouse Gas Initiative (RGGI)	The RGGI states applaud Virginia's progress toward implementing a market-based program to reduce GHG emissions. In considering Virginia's potential participation in our existing RGGI market, the RGGI states recognize many benefits of an expanded trading market, including increased economic efficiency and mitigation of the possibility of emissions leakage. Participation in RGGI has helped our states create jobs, save money for consumers, and improve the public health, while reducing power sector emissions and transitioning to a cleaner energy system. If implemented successfully, expanded RGGI participation will serve to amplify these benefits. The RGGI states recognize the importance of ensuring that any new entrant into the RGGI market is fully compatible with our existing program. In studying Virginia's potential compatibility, we considered the alignment of key program elements, consistency in the use of regulatory language, and comparable stringency of the program as a whole. Expanding the RGGI trading market brings many benefits provided that compatible programs can be established. Making the changes outlined above to Virginia's regulation will help to ensure compatibility so that, as a regulatory matter, Virginia can be considered a RGGI Participating State. The RGGI states are excited by the prospect of Virginia's potential participation in the RGGI program, and applaud Virginia's plans for investment in complementary programs such as energy efficiency and clean and renewable energy. We see an opportunity for Virginia to realize a measure of climate leadership by adopting a lower starting allowance budget than the 33-34 million tons currently proposed. The RGGI states' comments have been informed by productive conversations with Virginia state staff and Agency Heads. States hope to continue the discussions in the future as Virginia makes further refinements to this proposed rule. The RGGI states are available to assist Virginia in addressing these comments as the state continues towards the development of a compatible program.	Support for the proposal is appreciated. As discussed in the response to comment 37, the initial base cap has been set at 28 million tons.
137-1. RGGI	The proposed rule states at 6020 C: *"Allowance" means an allowance up to one ton of CO_2 purchased from the consignment auction in accordance with Article 9 (9VAC5-140-6410 et seq.) of this part and may be deposited in the compliance account of a CO2 budget source.* The RGGI states suggest that this definition be replaced by the following, in order to be consistent with the definition of "CO_2 allowance" in the 2017 Model Rule. This change would help ensure the proper functioning of the RGGI allowance market, including for purposes of	The proposal has been revised accordingly.

	tracking of allowances to be used for regulatory compliance with the RGGI program: *"CO_2 allowance" means a limited authorization by the* [REGULATORY AGENCY] *or a participating state under the CO_2 Budget Trading Program to emit up to one ton of CO_2, subject to all applicable limitations contained in this Part."*	
137-2. RGGI	a. The proposal is silent regarding the potential use of CO_2 offset allowances. The RGGI states recommend that the Virginia rule specify that CO_2 offset allowances will be accepted for compliance, up to a maximum 3.3% of any entity's compliance obligation. The RGGI states intend to amend the 2017 Model Rule to clarify the limit on offset allowance use. The RGGI states recommend inclusion of the following regulatory language on offsets, in order to be consistent with the to-be-amended 2017 Model Rule: *For CO_2 offset allowances, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of* [Section XX] *for a control period, initial control period, or an interim control period may not exceed 3.3 percent of the CO_2 budget source's CO_2 emissions for that control period or initial control period, or may not exceed 3.3 percent of 0.50 times the CO_2 budget source's CO_2 emissions for an interim control period, as determined in accordance with* [Subparts XX]. b. A definition of "CO_2 Offset Allowance" will be necessary to support inclusion of the offset language offered above. The 2017 Model Rule defines "CO_2 offset allowance" as: "*CO_2 offset allowance. A CO_2 allowance that is awarded to the sponsor of a CO_2 emissions offset project pursuant to section XX-10.7 and is subject to the relevant compliance deduction limitations of section XX-6.5(a)(3).* c. Note that these recommendations pertain to the fungibility and acceptance of CO_2 offset allowances for compliance under the RGGI trading program. The RGGI states leave it to Virginia's discretion whether Virginia wishes to establish state-specific offset protocols, and to issue CO_2 offset allowances to qualifying projects within the state. The proposed rule does not provide for the issuance of CO_2 offset allowances.	a. The proposal has been revised accordingly. b. The proposal has been revised accordingly with some modification. c. As discussed in the response to comment 26, Virginia is exercising its discretion to not implement offsets at this time.
137-3. RGGI	The proposed rule states at 6020 C: *"CO_2 Budget Trading Program" means the Regional Greenhouse Gas Initiative (RGGI), a multi-state CO_2 air pollution control and emissions reduction program as a means of reducing emissions of CO_2 from CO_2 budget sources.* The RGGI states suggest that this definition be replaced by the following, in order to be consistent with the definition of "CO_2 Budget Trading Program" in the 2017 Model Rule. Because this defined term is part of the regulatory definition of "Participating State," this change would help ensure that Virginia is considered a RGGI Participating State and that Virginia-issued allowances are fully fungible across the RGGI program: *"CO_2 Budget Trading Program" means a multi-state CO_2 air pollution*	The definition of "CO_2 Budget Trading Program" has been revised accordingly with some modification. No change has been made to the definition of "participating state" because the need for corresponding regulations is addressed in the CO_2 Budget Trading Program definition.

	control and emissions reduction program established pursuant to this Part and corresponding regulations in other states as a means of reducing emissions of CO_2 from CO_2 budget sources.	
137-4. RGGI	The proposed rule states at 6020 C: "*Beginning in 2020 and each calendar year thereafter, the CCR trigger price shall be 1.025 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent. The CCR trigger price in calendar year 2021 shall be $13.00. Each calendar year thereafter, the CCR trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1A."* The RGGI states note that the 2017 Model Rule modifies the CCR trigger price trajectory after 2020. The 2017 Model Rule states that the RGGI CCR will be $13.00 in 2021 and increase by 7% per year in the years following. To be compatible, RGGI states suggest the following: *"The CCR trigger price in calendar year 2020 shall be $10.77. The CCR trigger price in calendar year 2021 shall be $13.00. Each calendar year thereafter, the CCR trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1A."* Virginia's proposed rule displays a list of CCR trigger prices in Table 140-1A. These prices differ from those shown in the RGGI 2017 Model Rule by one cent, for the prices starting in 2024 and ending in 2030. Likewise, Virginia's proposed rule displays a list of ECR trigger prices in Table 140-1B. These prices differ from those shown in the 2017 Model Rule by one cent, for the years 2026, 2029, and 2030. Revised tables are provided.	These corrections have been made.
137-5. RGGI	The proposed rule states at 6020 C: *"'Conditional allowance' means an allowance allocated by the department to CO2 budget sources and to DMME. Such conditional allowance shall be consigned by the entity to whom it is allocated to the consignment auction…after which the conditional allowance becomes an allowance to be used for compliance purposes."* The RGGI states suggest a change to the final clause of this section, to clarify the relationship between a conditional allowance and a CO_2 allowance: "*…after which the conditional allowance becomes a CO_2 allowance once it is sold to an auction participant."* A similar issue exists in 6430, p. 959, where the proposed rule states: *"At the completion of the consignment auction, a conditional allowance shall become an allowance used for compliance purposes."* The RGGI states suggest a change to this language, to clarify the relationship between a conditional allowance and a CO_2 allowance: "*At the completion of the consignment auction, a conditional allowance sold at auction shall become a CO_2 allowance."*	The proposal has been revised accordingly.
137-6. RGGI	The proposed rule states at 6020 C: *"'Minimum reserve price' means, in calendar year 2020, $2.00."* The	The proposal has been revised accordingly.

	minimum reserve price for RGGI auctions in 2020 will be $2.32. The RGGI states recommend correcting this number in order to be compatible with the 2017 Model Rule.	
137-7. RGGI	The proposed rule states at 6020 C: *" 'Receive' or 'receipt of' means, with regard to CO_2 allowances, the movement of CO_2 allowances by the department or its agent from one COATS account to another, for purposes of allocation, transfer, or deduction."* This definition should match the updated definition in the 2017 Model Rule: *" 'Receive' or 'receipt of' means, when referring to the* [REGULATORY AGENCY] *or its agent, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the* [REGULATORY AGENCY] *or its agent in the regular course of business."*	The proposal has been revised accordingly.
137-8. RGGI	The proposed rule states at 6020 C: *"'RGGI, Inc.' means the 501(c)(3) non-profit corporation created to support development and implementation of the Regional Greenhouse Gas Initiative (RGGI). Participating RGGI states use RGGI, Inc., as their agent to conduct the consignment auction, and operate and manage COATS."* The RGGI states recommend deleting the definition of RGGI, Inc., while retaining the general concept of an agent designated to conduct auctions and manage allowance tracking.	The proposal has been revised accordingly.
137-9. RGGI	The proposed rule states at 6020 C: *"'State' means the Commonwealth of Virginia. The term 'state' shall have its conventional meaning where such meaning is clear from the context."* In clarifying the "conventional meaning" of the word "State," the rule should also incorporate the broader 2017 Model Rule definition: "*A State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands."* Also, the RGGI states recommend that the broader term "State" not be used in the Virginia regulation where the more specific term "Participating State" would be more appropriate. Where the term "Participating State" is used in the 2017 Model Rule, this term should also be used in the Virginia regulation instead of "State." This would help avoid confusion and ensure compatibility.	The proposal has been revised to eliminate the definition of "state" altogether and rely instead on the definition of "participating state." "State" is a commonly understood term, and there is no need to define it in this regulation. "Participating state" is an important term of art, and is properly defined separately.
137-10. RGGI	The proposed rule states in 6200 A & B: "*A. The department may retire undistributed CO_2 allowances at the end of each control period. B. The department may retire unsold CO_2 allowances at the end of each control period."* Conditional allowances should not be allowed to be transferred, except to be sold at auction, retired, or withheld as part of an ECR trigger event. Accordingly, this phrase should reference undistributed and unsold "conditional allowances" instead of "CO_2 allowances":	The proposal has been revised accordingly.

	"Undistributed or unsold conditional allowances shall not be transferred, with the exception of a transfer to consign them to auction, retire them, or withhold them in the event of an ECR trigger event. The department may retire undistributed conditional allowances at the end of each control period. B. The department may retire unsold conditional allowances at the end of each control period." A similar issue exists in 6210 E, where the proposed rule states: "*The department will convert and transfer any CO2 allowances that have been withheld from any auction or auctions in the prior year into the Virginia ECR account…The department will withhold CO2 ECR allowances as follows."* "Conditional allowances" should replace "CO_2 allowances." Also note that "in the prior year" has been removed from the 2017 Model Rule, and should be removed here: *"The department will convert and transfer any conditional allowances that have been withheld from any auction or auctions into the Virginia ECR withholding account…The department will withhold CO_2 ECR allowances as follows."*	
137-11. RGGI	The proposed rule states in 6210 I: *"Timing requirements for CO_2 allowance allocations shall be as follows. 1. By May 1, 2019, the department will submit to RGGI, Inc., the CO_2 conditional allowance allocations, in a format prescribed by RGGI, Inc., and in accordance with 9VAC5-140-6215 A and B, for the initial control period (2020). 2. By May 1, 2020, and May 1 of every third year thereafter, the department will submit to RGGI, Inc., the CO_2 allowance allocations, in a format prescribed by RGGI, Inc., for the applicable control period, and in accordance with 9VAC5-140-6215 A and B."* The RGGI states suggest removing references to RGGI, Inc. and replacing them with "its agent." This section should also replace "CO_2 conditional allowance" and "CO_2 allowance" with "conditional allowance": "*Timing requirements for CO_2 allowance allocations shall be as follows. 1. By May 1, 2019, the department will submit to its agent the conditional allowance allocations, in a format prescribed, and in accordance with 9VAC5-140-6215 A and B, for the initial control period (2020). 2. By May 1, 2020, and May 1 of every third year thereafter, the department will submit to its agent, the conditional allowance allocations, in a format prescribed, for the applicable control period, and in accordance with 9VAC5-140-6215 A and B."*	The proposal has been revised accordingly with some additional modification to improve clarity.
137-12. RGGI	The proposed rule states in 6020 C: *"'Fossil fuel-fired' means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 10% of the annual heat input on a Btu basis during any year."* This definition is inconsistent with and less stringent than the 2017 Model Rule, which sets a threshold of 5% of the annual heat input on a Btu basis during any year. The applicability provisions of the	The proposal has been revised accordingly.

	Virginia rule should be consistent and at least as stringent as those of the 2017 Model Rule. This change is necessary in order to ensure that Virginia's regulation is a corresponding CO_2 Budget Trading Program regulation, such that Virginia can be considered a RGGI Participating State.	
137-13. RGGI	The proposed rule states in 6040 B, p. 938: *"Exempt from the requirements of this regulation is any fossil fuel power generating unit owned by an individual facility and located at that individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility."* This provision does not set a threshold for what constitutes "primary use of operation of the facility." In the 2017 Model Rule, facilities that provide less than 10% of their power output to the grid are exempted from compliance obligations. The RGGI states suggest that the Virginia rule consistently adopt this 10% threshold. The applicability provisions should be consistent and at least as stringent as those of the 2017 Model Rule. This is necessary in order to ensure that Virginia's regulation is a corresponding CO_2 Budget Trading Program regulation, such that Virginia can be considered a RGGI Participating State.	The proposal has been revised accordingly.
137-14. RGGI	The proposed rule states in 6210 D 1: *"The department will initially allocate…CO_2 CCR allowances for calendar year 2020."* RGGI states suggest that Virginia clarify how the CCR provisions will work.	The proposal has been modified to specify that CCR allowances will be allocated on a pro rata basis to CO_2 budget sources.
137-15. RGGI	The proposed rule states in 6260 A: *"CO_2 allowances that meet the following criteria are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an interim control period."* This section mentions requirements for both a "control period" and an "interim control period." However, the Virginia proposed rule includes a third type of control period, the "initial control period.” This "initial control period" includes only the year 2020, as a means of synchronizing with the RGGI states' compliance schedule. RGGI states suggest that the "initial control period" should also be mentioned here, to specify that compliance requirements apply in 2020: *"CO_2 allowances that meet the following criteria are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for an initial control period, a control period, or an interim control period."*	The proposal has been revised accordingly.
137-16. RGGI	The proposed rule states in 6430, p. 959: "*[C]onditional allowances shall be consigned by the CO2 budget source…or DMME to each auction on a quarterly pro rata basis in accordance with procedures specified by the department."* The RGGI states understand the "quarterly pro rata basis" to mean that generators must consign one quarter of their yearly total of conditional allowances at each auction, rather than distributing the	The proposal has been revised accordingly.

	consigned amount over the quarterly auctions at their own discretion. RGGI states suggest that this language be made more explicit in the Virginia rule: "*One quarter of the annual conditional allowance allocation shall be consigned by the CO_2 budget source…or the holder(s) of a public contract with DMME to each auction in accordance with procedures specified by the department."*	
138. Richard Ball	A baseline as high as 33 or 34 MMT of CO_2, as proposed, would be much too high and lead to much less reduction in Virginia CO_2 emissions by 2030 than is feasible and desirable. For example, the ICF/DEQ Policy scenarios show very low reductions in CO_2 emission reductions. Emissions have already been coming down since 2016 and most projections indicate that a trend in that direction is likely to continue in that direction even in the absence of the proposed regulation. I offer several lines of evidence for that, including calculations of actual 2017 emissions in Virginia for overall electric power emissions and emissions specifically from likely EGUs covered by the regulation. If the baseline is set in the range of 30-34 MMT of CO_2, the program might fail to achieve CO_2 reductions that are substantially greater than what would happen even in the absence of the ED 11 program. My conclusion is that it would be feasible to achieve reductions under a base cap of 28 MMT with an aggressive, but feasible solar or wind expansion program and phasing out a substantial amount of higher ED 11 CO_2 carbon sources along with considerable natural gas generation while maintaining a steady level of total Virginia generation. It also implies that it makes little sense to continue expanding natural gas generating sources since they are likely to be constrained in their generation. A steady level of generation would be consistent with an aggressive program of energy efficiency measures, which might be implemented as a result of new legislation enacted in the 2018 session of the General Assembly. RGGI expects Virginia to reduce its baseline cap, although they did not specify a particular value. In my analysis, I have borrowed results on the likely list of ED 11 EGUs that will be covered under ED 11 and the associated estimated generation, and CO_2 emissions from the comments submitted by the Virginia Chapter of the Sierra Club. Another conclusion is that the ICF modeling results published by DEQ in the autumn contained some out-of date assumptions due to subsequent events. I conclude that: the ICF results were furnished in autumn, 2017 before actual 2017 results for Virginia were known and before SB 966 was passed in the 2018 Session of the General Assembly, and before the announcement of retirement plans for a number of EGUs, so those factors	Support for the proposal and the commenter's observations on the base cap are appreciated. As discussed in the response to comment 37, the base cap has been set at 28 million tons.

	could not be reflected in the modeling. In particular, CO_2 emissions by 2020 EGU-covered units in 2017 was overestimated in the ICF modeling as 32 MMT CO_2 , compared with the Sierra Club's estimate of 29 million tons based on actual 2016 data. Those factors also may have led to overestimation of subsequent modeled results for 2020 through 2030. Hence I look at likely emission reductions for other baseline cap values than just 33 MMT under several different policy assumptions.	
139. Southern Environmental Law Center (SELC)	DEQ has broad legal authority to promulgate regulations to reduce CO_2 pollution through an emissions trading program. Specifically, the board is authorized to regulate air emissions, which includes CO_2. The Virginia Code authorizes the Air Board to "develop a comprehensive program for the . . . abatement and control of all sources of air pollution in the Commonwealth." This power includes the ability to "promulgate regulations . . . abating, controlling and prohibiting air pollution[.]" The law defines "air pollution" as "the presence in the outdoor atmosphere of one of more substances which are or may be harmful or injurious to human health, welfare or safety, to animal or plant life, or to property, or which unreasonably interfere with the enjoyment by the people of life or property." CO_2 clearly qualifies as a "pollutant" subject to board regulation. Indeed, it is well settled on a national level that CO_2 is a pollutant needing regulation. The Supreme Court held in Massachusetts v. EPA that GHG, including CO_2, are "without a doubt" pollutants under the Clean Air Act. Subsequently, EPA determined that GHG emissions endanger the public health and welfare. Virginia Code requires the board to "make . . . such investigations and inspection and do such other things as are reasonably necessary to carry out the provisions of this chapter . . . including the achievement and maintenance of such levels of air quality as will protect human health, welfare and safety[.]" At the state level, carbon pollution is a clear threat to Virginian's health, welfare and safety. Virginia's coast faces the highest level of sea level rise on the Atlantic Coast of the U.S. Sea level rise is also a threat to public and private property, including the Norfolk Naval Base and the Hampton Roads region, which is becoming increasingly vulnerable to flooding. A report issued by the Virginia Institute of Marine Science predicts sea level rise will increase in the Hampton Roads area by more than a foot between 2018-50. Moreover, in Virginia, climate change is exacerbating chronic respiratory diseases. Because of the clear danger carbon emissions pose to human health, welfare and safety, it is well within the board's broad legal authority to regulate these harmful pollutants. Linking to RGGI preserves Virginia's autonomy, while addressing the threat carbon emissions pose to the state in a cost-efficient manner.	Support for the proposal is appreciated. As discussed here and, for example, the response to comment 76, the board clearly has the authority to address demonstrated negative GHG effects in accordance with its mandate to protect public health and welfare.
140. SELC	Covering new and existing fossil fuel-fired units prevents	See the response to

	a market perversion where power generators could shift generation away from regulated plants to new, unregulated power plants, which would not produce a reduction in statewide carbon emissions. We are also glad to see that the regulation applies to all CO_2 emitted from co-firing units that include at least one fossil fuel-fired unit. However, the final regulation should include all electric power facilities that emit CO_2, regardless of fuel type. Specifically, the regulation should apply to any 25 MW unit that burns biomass. The science is clear that burning certain biomass, particularly forest-derived biomass, increases net atmospheric CO_2 for 35-100 years or more, compared to fossil fuels. Numerous studies have shown that burning chips or pellets made from standing trees puts more CO_2 in the atmosphere than continuing to burn coal in existing or new power plants. One report showed the use of whole trees from naturally regenerated forest in the U.S. for power production could result in four times the amount of carbon in the atmosphere versus burning coal over a 100-year timeframe. Thus, it is critical that the regulation cover all net carbon emissions. Straightforward carbon accounting protocols such as those advocated by the Partnership for Policy Integrity (PFPI) demonstrate that even under the best case scenario, emissions from wood-burning plants exceed those from fossil fuel-fired plants for periods of one to two decades and beyond. As a result it is most reasonable to include all biomass stack emissions under the cap. Should DEQ wish to provide some credit to generators who are burning true wastes or residues, PFPI has offered a calculator that can be used to find the net emissions over the regulatory time frame. This framework would appropriately weight emissions from industrial facilities burning black liquor as having nearly zero net emissions, as the framework assumes that black liquor would be burned for disposal even if energy recovery does not occur. It would also reflect the net impact of burning wood residues more accurately than the current effective assumption that emissions are zero, when biomass facilities are not covered under the cap. DEQ should amend the regulation to include "any unit combusting carbon-based fuels that serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe . . . and any sources that includes one or more such units shall be a CO_2 budget sources, subject to the requirements" of the regulation.	comment 67 for detailed discussion of how biomass will be treated.
141. SELC	SELC supports a 33 million ton base budget and 3% reductions annually thereafter, but encourages DEQ to consider actual emissions data from 2019 to determine whether the 2020 cap should be revised down. Contrary	As discussed in the response to comment 37, a cap of 28 million tons has been set.

	to concerns raised in comments to the NOIRA, compliance with Version 1 is in fact readily achievable. Dominion's 2017 IRP created a Plan Alternative for Clean Power Plan compliance which readily met the Virginia limit of 27,830,174 tons of CO_2 by 2030. Version 1 of the regulation requires 23.10 million ton cap by 2030. However statewide carbon emissions in 2017 were 31.2 million tons, which are lower than the Version 1 baseline of 33 million tons. Also note that SB966, passed by the General Assembly in 2018, proposes 5,000 MW of renewable, carbon-free generation and over $1 billion in energy efficiency investment between now and 2028. With this new landscape, we encourage further modeling to predict what 2018 and 2019 emissions are likely to be and recommend a starting baseline that is the lower of Version 1 or DEQ's updated forecast for actual 2019 carbon emissions. This allows DEQ to avoid setting a baseline cap that is higher than actual emissions in the first compliance year. A lower initial base budget and more stringent overall cap by 2030 also better achieves the goal of reducing CO_2 emissions, growing Virginia's clean energy economy, and protecting the public health and welfare. We support the decision to implement a 3.0% per year reduction in carbon emissions over 10 years beginning in 2020. This results in a base budget of 23.10 million tons by 2030. While this is a good initial reduction and sensible 10-year goal, SELC encourages a 10 year review provision. This 10-year review provision would ensure that Virginia continues to reduce its carbon emissions beyond the initial 10-year goal and determine emissions reduction goals beyond 2030.	The regulation has been amended to specify that the department will review the base budget and recommend appropriate adjustments in the base budget for 2031 and succeeding years, considering the best available science and all relevant information and policies available from any CO_2 multi-state trading program in which Virginia is participating. In the context of the RGGI program as a whole, it is important to remember that the program is subject to routine program review. As discussed elsewhere, the RGGI states routinely review and evaluate how current strategies are working, and look ahead to what changes are needed to the program to insure its ongoing effectiveness. RGGI's comprehensive program reviews will consider program successes, impacts, and design elements. As part of this process, DEQ will evaluate where Virginia needs to go with respect to budgets and allowances. In order to be transparent and effective, this must be effected through the program review process in concert with the other RGGI states.
142. SELC	SELC supports the 5% set aside to assist DMME in efforts to abate and control air pollution, although we encourage DEQ to evaluate whether a 10% set aside would produce more benefits than it would increase costs for covered entities. SB966's commitment to energy efficiency is a notable improvement on the role efficiency will play in Virginia's energy future, but there can always be better and more diverse initiatives to bring this lowest-cost resource to Virginia. Despite being the lowest-cost energy resource, energy efficiency measures	Support for the proposal is appreciated. As discussed in comments 51 and 83, a relatively small 5% set-aside is appropriate in the early stages of the program, although this amount may be revisited as a result of program review.

	are also among the most labor-intensive, which means that the effect of every dollar spent on efficient has greater economic ramifications that dollars spent on more traditional, supply-side energy resources. A recent study by Applied Economic Clinic of Virginia's possible energy efficiency future found that under a "medium efficiency" scenario, total annual electricity sales in Dominion's territory could actually decrease. As Virginia's in-state generation fleet becomes less carbon intensive as a product of SB966, a decrease in total energy sales only amplifies the possible reduction in statewide carbon emissions. The study also confirmed that a "medium efficiency" scenario could lower customer bills by up to 0.3% by 2028. The 5% (or possible 10%) set aside can play a key role in helping Virginians achieve lower carbon pollution and lower electricity bills.	
143. SELC	The proposal includes several important cost management mechanisms, similar to those provided for in the RGGI program. SELC supports the inclusion of these provisions as they are designed to provide enhanced market flexibility and stability, and have proven to be important in establishing a successful cap-and-trade program. Consistent with the RGGI program, the regulation allows covered entities to bank unlimited CO_2 allowances. SELC supports this provision, so long as it is clear banking can occur for allowances purchased at auction. Banking provides flexibility and has been shown to encourage sources to reduce their emissions sooner and below required levels. Banking ensures that all CO_2 reductions have a long-term economic value, and not merely short-term value for immediate compliance purposes. By using banking, participants are very adept at smoothing the supply of allowances over time--for example, banking allowances in early compliance periods in anticipation of increased allowance scarcity in later periods. Research on other cap-and-trade programs without banking indicates that such programs typically result in "just-in-time" emission reductions, rather than encouraging cost-effective, long-term emissions reductions. The budget adjustment for banked allowances is necessary due to the high volume of allowances banked during early compliance periods where the volume of RGGI allowances far exceeded actual emissions. Although the RGGI states significantly lowered the regional cap to more closely reflect actual emissions, participants had already banked large numbers of allowances. In 2014, for example, there were an estimated 140 million tons of banked allowances, significantly exceeding that year's emission cap of 91 million tons. Even with the significant cap reduction in 2014, emission reductions were unlikely to occur without further adjustment to account for the volume of banked allowances. These adjustments have been in place for	DEQ agrees that RGGI's cost management mechanisms will ensure that the emissions cap is maintained while managing prices and assuring a stable market.

	several compliance periods, with the third such adjustment period applying to allocation years 2021-25. Virginia sensibly includes this adjustment, which should further the goal of reducing CO_2 emissions in an economically efficient manner. SELC supports the CCR allocation, although improvements should be considered in the coming years to ensure that such reserves are only triggered during truly unexpected price spikes. In the event the allowance price exceeds a specified price ("trigger price"), the CCR mechanism introduces a limited quantity of additional allowances into the auction to increase the supply and thereby reduce the cost. After being implemented in 2014, the CCRs have already been triggered twice, which raised concerns that the containment mechanism is not functioning as intended. Instead of being reserved for truly extreme and unexpected market spikes, the CCR trigger prices may have been set too close to anticipated allowance prices, resulting in 15 million reserve allowances being added to the market. Some have argued that these additional allowances were unnecessary, given the large quantities of banked allowances. In 2017, after another design review, RGGI implemented several changes to the CCR mechanism, which should help prevent unnecessary allowances from being released into the market. For example, the trigger price was initially set at $4 in 2014 raising to $10 in 2017, and thereafter escalating by only 2.5% each year. Now the trigger price will be set a $13.00 in 2021 and increase by 7% every year. Additional changes to the CCR mechanism should be considered. Most importantly, the proposal, consistent with the RGGI program, provides that every year, additional allowances--up to 10% of the emissions cap--can be allocated and sold at auction in the event of a trigger. While this mechanism should help to contain cost, it also effectively increases the overall cap. Virginia, along with other participants in the RGGI auction process, should consider whether additional modifications could better balance carbon emission reduction with cost concerns. For example, it may be more effective to generate CCRs by borrowing allowances against future years or from allowances unsold at auction, rather than generating additional allowances. This sort of program-level borrowing would maintain the overall emissions cap across the initial 10 year program, while still protecting against short-term price spikes. SELC also supports the ECR. There is inherent price uncertainty in a market-based cap-and-trade program due to factors such as natural gas price volatility, variable electricity demand, uncertainties associated with nuclear projects, and evolving renewable energy programs. Where prices are significantly higher than	

	anticipated, the CCR is designed to increase supply and reduce cost. Prior to 2017 changes, however, there was not an analogous mechanism if prices were lower than anticipated. Instead, the RGGI program relied only on a reserve price--a minimum acceptable bid. In 2017, the RGGI program changed its model rule to incorporate an ECR, which Virginia has incorporated into the regulation. In the event allowance prices fall below established triggers, Virginia, like other RGGI states, will withhold up to 10% of its allowances from circulation. According to the RGGI model rule, the ECR trigger price is set at $6.00 in 2021 and will rise at 7% each year. This cost management mechanism should help further Virginia's overall policy goal of reducing carbon emissions in the event that emission reduction costs are lower than projected. Initial modeling of this mechanism indicates that it should further incentivize carbon emission reductions. In situations of low demand and low prices, i.e., situations where the emissions containment reserve is likely to be triggered, a cap-and-trade program is typically not driving emission reductions. Modeling of the emission containment reserve should better align incentives for individual actors in the region and make the auction price more responsive to supply.	
144. SELC	SELC supports the 3-year review, updating output-based allowance allocation method. This method of allocating allowances based on a rolling average of emissions over the past 3 years ensures that where generators do not use the full amount of allowances received over 3 years, these allowances can be retired or banked, and not hoarded by the generator. To the extent any parties express concern about leakage, we believe DEQ has adequately addressed that issue with its continually-updating output system. In any event, emissions leakage is not likely to become an issue. Some critics have argued leakage would occur in RGGI states, yet studies have found that these concerns have not materialized. Indeed, RGGI's most recent Monitoring Report found no evidence of significant leakage. Moreover, Dominion Energy's 2017 IRP demonstrated Clean Power Plan compliance was possible without significant increases in purchased power. While Plan CT is not an exact match to the proposed trading program, it demonstrates Dominion's ability to comply with a significant carbon emissions reduction program without resulting in emissions leakage. Thus, while leakage is unlikely to become an issue under the proposed system of emissions reduction, the allocation method used in the proposal should address concerns raised by those who fear leakage to be an issue with cap and trade systems.	DEQ agrees that the 3-year review, updating output-based allowance allocation method will best control allowance distribution while avoiding potential leakage.
145. SELC	The regulation should ensure the program is the most economically advantageous for customers and families. While we support banking of allowances, we only support banking of allowances that a unit has purchased in the market, not banking of allowances received at no	The commenter's concerns are appreciated. The definition of "conditional allowance" has been amended to specific that a

	cost from DEQ and not submitted to the RGGI auction. Article 9 must make clear that all generators are required to sell all allowances back into the consignment auction. Without a full-market participation requirement, a generator could hoard a large share of CO_2 allowances in order to influence prices or prevent competitors from obtaining allowances. To ensure this anti-competitive behavior does not occur, the regulation must ensure 100% of conditional allowances make it to the consignment auction. While the system appears designed in such a way, additional language could help clarify this important point. Generators initially receive conditional allowances for free, prior to selling into and buying back from the consignment auction. Systems with free allowances have commonly led to windfall profits for generators, to the detriment of customers. However, free allocation systems can be done in a way that prioritizes customers. The final regulation should include a review mechanism to prevent these windfalls for generators and ensure that customers benefit. One means to achieve this is through SCC review of how these windfall profits are used. Indeed there are a number of ways that customers could benefit from allowance profits, whether directly through rate credits, or indirectly through greater emissions reductions, investments in energy efficiency, or other reductions in compliance costs. SELC urges the board to collaborate with the SCC in its review of how generators use windfall profits in order to achieve the greatest level of carbon emissions reduction in the most economically advantageous way for customers. For instance, one possible windfall could occur where a generator sells more allowances in RGGI than it buys back for its own compliance, making it a net seller. In that scenario, the generator is revenue positive as a result of the trading program, but DEQ will have information regarding how many allowances that utility received, how many it surrendered in compliance, and what the various market prices were, which DEQ could make public and also provide to the SCC as it reviews utility earnings and expenses in upcoming triennial rate cases and annual fuel factor dockets. DEQ should also include some failsafe mechanism to ensure that the generator does not profit from the trading program at customer expense as a result of inadequate SCC oversight.	conditional allowance becomes a CO_2 allowance once it has been sold to an auction participant. The RGGI states suggested this change to clarify the relationship between a conditional allowance and a CO_2 allowance. DEQ agrees that collaboration with the SCC is an important element of ensuring that the carbon trading program operates properly in the context of SCC responsibilities
146. Virginia Chapter of the Sierra Club, Appalachian Voices; Virginia Interfaith Power and Light;	Virginia's proposal to develop a CO_2 trading program that links to the existing RGGI program is an appropriate mechanism to begin reducing CO_2 emissions in Virginia. Although improvements should be made, we support action to limit and reduce CO_2 emissions from power plants and to link to RGGI's larger market. The proposal's goal of reducing CO_2 by 30% from 2020-30, at an annual rate equal to 3% of the base year allowances, is modest and can readily be achieved as demonstrated	Support for the proposal is appreciated. DEQ agrees that linking to RGGI will benefit the Commonwealth by protecting public health and welfare in a fiscally responsible way.

Environment Virginia; Chesapeake Climate Action Network.	by planned actions that will reduce emissions and by actual experience in the RGGI states. Importantly, the proposal intends to achieve actual CO_2 reductions, not reductions in carbon intensity which can disguise emissions increases as decreases in the rate of emissions-per-MWH of generation. Dangerous climate change is driven by actual CO_2 emissions and atmospheric CO_2 levels, not the intensity of emissions. While Virginia could potentially implement CO_2 reduction requirements without tradable emissions allowances, linking Virginia's proposed plan to RGGI is a good choice. Through 2016, RGGI states had reduced CO_2 emissions from covered power plants by 40% from 2008. RGGI reduced CO_2 emissions at faster rates and with lower costs and greater benefits than predicted. Moreover, those emissions reductions were achieved while customer bills were reduced and while the economies of participating states grew. Reductions in air pollution in RGGI states have improved health outcomes. RGGI's program has been so successful that its member states recently agreed to build upon CO_2 reductions already achieved, so that covered sources reduce CO_2 by an additional 3% per year for 10 years between 2020-30, achieving an overall reduction of more than 65% compared to its initial 2009 cap. Joining this established CO_2 market will help Virginia reduce CO_2 smoothly and cost-effectively, and would avoid the potential pitfalls from implementing a Virginia-only market. The market for allowance trading will enable power plant operators to buy or sell allowances as appropriate to their individual circumstances, while aggregate CO_2 emissions decline. Since RGGI is both very successful and the only functioning CO_2 market in the eastern U.S., it would make no sense to go it alone. Under a consignment auction approach, the value of allowances will go to covered power generators, and utilities will be able to use the funds, subject to regulatory oversight, to reduce electricity rates and to support incremental investments in zero-carbon energy sources and energy efficiency. Such zero-carbon energy investments will further mitigate electric energy costs by reducing fuel purchase requirements. In its 2017 IRP proceeding, Dominion acknowledged that solar costs have fallen dramatically and that solar is now the cheapest form of energy. Both utility and non-utility generators should be required or encouraged to invest such funds in renewable energy and energy efficiency, or, at minimum, to pass consignment revenues through to retail customers. The allocations of conditional allowances can be reconsidered if consignment revenues are not used to advance the rule’s goals. The emission reductions contemplated by ED11 are	

	readily achievable. RGGI's market began full operation in 2009. By 2012-14, the average annual CO_2 emissions from the 2009 baseline had been reduced by 35.7%; and annual emissions in 2016 were 40% below those in 2008. Those reductions occurred in far less than 10 years, and RGGI reduced caps to reflect the more rapid progress. RGGI is now planning to reduce its CO_2 cap by an additional 3%/year from 2021-30, thereby achieving a 65% reduction from its initial 2009 allowance cap. Significantly, AEP recently announced its voluntary commitment to reduce its CO_2 emissions from power production by 60% from 2000 levels by 2030 and by 80% by 2050. Its planned CO_2 reductions will be achieved through increased reliance on wind and solar energy, retirements of coal-fired plants, natural gas, greater energy efficiency and grid modernization, and the reductions are to be achieved even as electric demands may increase with greater electrification of the economy. Although AEP's planned reductions fall short of what will ultimately be needed to adequately mitigate global warming, they nevertheless illustrate that willing electric utilities can substantially reduce CO_2 emissions, consistent with customer and shareholder interests. AEP explains that its new clean energy strategy is driven by investors, business risks and the known need to reduce CO_2 in order to limit the global average temperature rise to less than 2°C. In short, the proposal is modest, achievable and reflects the unquestionable need to shift to clean energy as soon as practicable.	
147. Virginia Chapter of the Sierra Club et al.	The mix of generation and emissions is changing rapidly and will change more by 2020. The proposed initial aggregate cap of 33-34 million tons for 2020 is too high and out of date. A too-high initial cap will distort RGGI's markets by artificially inflating the pool of allowances. It would fail to produce real reductions in CO_2 and could lead to higher emissions. The 2020 cap should be set below 30 million tons, subject to updating the 2020 level in a proceeding to be held in early 2019. Updating the 2020 baseline based on the latest available information would be fair to the public and all parties. At the same time, setting a cap below 30 million tons would reflect the most current information and would give better planning notice to owners of budget sources than overstated estimates of 33-34 million tons. However, if the baseline is set at 33-34 million tons, then the annual rate of reductions should be increased to 3.5% per year, which would still be slower than RGGI's average annual reduction over its first 10 years. Changes in the fuel mix are occurring now and more changes are expected. The 2020 baseline should take into account all planned fossil fuel retirements and deactivations between now and 2020. It should also recognize that approved new natural gas facilities will displace emissions from coal plants that remain open.	A base cap of 28 million tons has been selected; see the response to comment 37 for more information.

	Between 2016-17, natural gas use in Virginia's electric power sector rose, while coal-combustion fell and retail sales fell. From 2016-17, the capacity factors of two of Virginia's largest coal-fired plants dropped by over 40%, and the CO_2 emissions just from those plants dropped by 4,989,186 tons, from 11,783,154 in 2016 to 6,793,968 tons in 2017. Recent additions of natural gas-fired generation have occurred and more are expected; they will continue to push out dirtier coal-fired plants. Traditional coal plants emit roughly 2.75 times as much CO_2 per MWH than new combined cycle plants, so the trend is toward a much lower CO_2 baseline in 2020. We estimate that the addition of the Greensville plant could displace 7 million tons of CO_2 from coal plants even at a modest 70% capacity factor. Beyond 2017, a number of retirements are expected. In its 2017 IRP, Dominion discussed potential fossil fuel plant retirements. On January 16, 2018, Dominion announced a number of retirements by filing with PJM deactivation requests for 9 fossil fuel units. Collectively, these units have a combined nameplate capacity of over 1,700 MW and emitted around 2.4 million tons of CO_2 in 2016, or 7% of the state's reported power emissions. In addition, Dominion announced the planned retirement of Yorktown 1 & 2. The Spruance and Edgecombe Genco plants have also notified PJM of their intent to retire in 2019 and 2020. Combined, this merchant capacity reflects another 300 MW of capacity and 1 million tons of annual CO_2 emissions. These announced retirements (which would account for 3.4 million tons of CO_2) and any other planned retirements or cold storage of units should be incorporated into calculation of the 2020 baseline. We looked at data for units that operated in 2016-17 and are not scheduled for retirement, and found that 2017 CO_2 emissions from covered fossil-fuel units that will still be operating in 2020 were approximately 29 million tons and the trend was downward, particularly for coal-fired units. The 2020 baseline should incorporate planned renewable energy developments through 2020. Energy from utility scale solar and wind is cheaper than from fossil fuels, and many customers are willing to provide the capital for small-scale solar. The estimates should reflect the improved prospects for renewables, which were boosted by recent legislation as well as by the low cost of solar and wind generation. According to the 2017 Virginia Solar Energy Development and Energy Storage Authority Annual Report, there are presently 219 MW of solar installed and an additional 2,703 MW under development. The PJM queue identifies 8 solar projects with a combined nameplate capacity of 717 MW with projected in-service dates between 2018-20 that would interconnect in Virginia. It is likely that additional solar	

	will be added through 2020 as a result of third-party investments or arrangements with utilities, such as the agreement between Dominion and Amazon to install solar. Recent legislation calls for approximately 5.5 GW of solar generation by 2028. These developments must be accounted for in developing the baseline. Since Dominion serves an integrated system in Virginia and North Carolina, the 2020 cap should also take into account solar connected to Dominion's system in North Carolina which will tend to reduce Dominion's need to generate energy in Virginia. Dominion has emphasized the growing electric demand for data centers. However, such loads are specifically asking for renewable energy. Those loads will add more to zero-carbon generation than to fossil fuel generation. A group of data companies submitted a September 2017 letter to the SCC in Dominion's IRP docket. They asked regulators to take energy resource preferences into account when deciding on future energy infrastructure projects to meet energy load growth from data centers. Citing economic, environmental and market needs, they explained why they wanted more renewable energy and why the IRP under-deploys renewable energy. Thus, demands for solar energy will limit future CO_2 increases even if load grows. This should be considered in setting a baseline below 30 million tons. Electric loads have flattened in recent years. Virginia's retail electricity usage declined between 2016-17. To the extent DEQ's analysis of the 2020 cap relies on Dominion's load forecasts, it should step back. Dominion's forecasts of load growth have been consistently overstated. Virginia's baseline should also account for the state's untapped energy efficiency potential and reflect savings that can be achieved by 2020 and beyond. Electricity generators should not get a higher CO_2 cap for 2020 because Virginia's utilities failed to meet the goal for efficiency-driven demand reductions of 10% compared to 2006 demand. Virginia should not reward its utilities with a higher baseline for CO_2 emissions, which would elevate emissions caps for at least a decade, based upon an indifferent approach to efficiency.	
148. Virginia Chapter of the Sierra Club et al.	We strongly support the proposed definition of "fossil fuel-fired" which would cover most co-firing of biomass and fossil fuels. However, the requirement to purchase CO_2 allowances should be extended to cover all biomass generation meeting the otherwise applicable size requirements. The requirement to purchase allowances should extend to new and existing biomass-fueled units, particularly those that burn wood-based biomass, which is the least likely to result in CO_2 recapture within a time frame helpful to avoiding the looming climate crisis.	The commenters' concerns about biomass are recognized; see the response to comment 67 for more information.

	The premise for exempting generators that burn biomass is that the emitted CO_2 will eventually be recaptured by regrowth of the feedstock and that is sufficient to mitigate the climate damages from current CO_2 emissions. Those assumptions are faulty in several respects. Biomass burns less efficiently than coal or natural gas so more biomass must be burned to produce each MWH of electricity, resulting in CO_2 emissions that are substantially higher than from coal and natural gas. Co-pollutants from biomass combustion are large and harmful to human health. Gradual deterioration of wood residues occurs over many years, but the net CO_2 emissions impacts from burning even residues remain large. Adverse climate and health impacts from burning biomass will not be offset by resequestration of CO_2 in the future, even assuming that the biomass is replaced with comparable forests. Exempting biomass from carbon prices would undercut beneficial investments in zero-carbon alternatives, which mitigate climate harms in the near- and long-term. There is no support for the assumption that forests will be regrown in a sustainable way or in sufficient quantities to recapture that CO_2. Furthermore, past investments in large biomass facilities do not deserve special treatment any more than past investments in fossil fuel-fired facilities. The public and climate are harmed by CO_2 emissions in both cases. The climate crisis will never be resolved if previously built emitters are granted exemptions. In any event, value of allowance auction revenues can be passed through to customers to mitigate cost impacts.	
149. Virginia Chapter of the Sierra Club et al.	The rule should be amended to require continued annual reductions of the CO_2 cap beyond 2030, at the same annual quantities as from 2021-30, until the rule is modified. This could be achieved by altering 9VAC5-140-6190 C to state: "For 2031 and each succeeding calendar year, the Virginia CO_2 Budget Trading Program base budget will be reduced by the same annual quantity as the reduction between 2029 and 2030." Continuing to reduce CO_2 at the same annual rate would mean a reduction of approximately 1 MM tons/year, which would achieve a 90+% reduction by 2050. The key is to clearly indicate that reductions will continue until climate stabilization is achieved. If a specific post-2030 target is desired then the rule could provide that yearly reductions of the annual cap will continue, for example, either until the emissions cap on covered sources has been reduced by 90% from the 2020 base budget or until the emissions cap on covered sources has been reduced by the same percentage as has been achieved by RGGI member states relative to their pre-auction emissions. Since RGGI's announced 2030 reduction target is more than 65% below its 2009 cap the latter measure would continue reductions until at least that percentage of emissions reduction is achieved in Virginia--or until greater reductions are achieved if RGGI extends its	The proposal has been amended to clarify that CO_2 reductions will indeed continue to be required after 2030; see the response to comment 141.

	annual reductions beyond 2030. This would assure that Virginia eventually catches up with a level of reductions that RGGI has shown are achievable. At minimum, it is necessary to clarify that the emissions trajectory post-2030 will be at least as stringent as that agreed to by the RGGI states in subsequent program reviews for the post-2030 years. Absent emission reductions that continue to at minimum match the stringent of the RGGI program beyond 2030, Virginia would be unable to continue to link its program with the RGGI states and reap the benefits of the larger carbon market.	
150. Virginia Chapter of the Sierra Club et al.	Climate change disproportionately harms the poor and other disadvantaged communities. Residents near and downwind of fossil-fuel power plants suffer disproportionate health impacts from co-pollutants such as particulates, SO_2, ozone, and mercury, and are disproportionately low-income or minority. Generating electricity with biomass also produces high levels of harmful air pollution. In contrast, solar, wind and efficiency do not produce any carbon pollution or co-pollutants. Over half a million people in Virginia live within three miles of a power plant that was to be covered by the Clean Power Plan. Of these, 52% are minority and 34% are low-income, while Virginia has a total minority population of 35% and low-income population of 26%. According to the U.S. Office of Minority Health, black people are three times more likely to die from asthma-related causes than white people. Capping and steadily reducing aggregate CO_2 emissions and co-pollutants will generally improve health outcomes in Virginia and benefit all communities, including disadvantaged communities. This positive benefit from reducing CO_2 has been documented in RGGI states, which have experienced improvements in health outcomes since RGGI's carbon limits took effect. RGGI states have also seen dramatic reductions in SO_2. It is possible that trading could allow some fossil fuel plants to use allowances to continue or increase polluting operations. As a result, localized harms may occur even if the rule produces overall progress. It is therefore critical that DEQ commit to conduct EJ and emissions studies; to continuously monitor and report concentrations of CO_2 and non-CO_2-pollutants to ensure that disproportionate concentrations do not harm particular communities or regions; to investigate detected concentrations as well as any complaints of disproportionate local impacts and to pursue appropriate remedial actions. We urge DEQ to consider amending the rule to prohibit plants fired with coal, biomass or heavy oil from acquiring allowances to increase their annual emissions over historic levels without first obtaining a permit.	DEQ agrees that disadvantaged communities must be specifically addressed in the context of wider EJ programs at the state level and has amended the proposal accordingly; see the response to comment 55.
151. Virginia Chapter of the	The proposal to cover existing units serving a generator of 25 MWe or larger is generally consistent with RGGI's	The applicability limit is indeed designed to be

Sierra Club et al.	existing rule. However, the rule should be amended to state that the 25 MWe threshold only needs to be crossed once to trigger coverage by the rule. This is important so that coverage cannot be avoided through manipulation of a unit's size or configuration. 9VAC5-140-6040 A should be modified to state that the rule covers units serving all generators having a nameplate capacity of 25 MWe or more "at any time on or after" a fixed date. To be consistent with RGGI's model rule, it would be reasonable to adopt January 1, 2005 as the on-or-after date. Alternatively, the on-or-after date could be shortly prior to the first notice that a plant might be covered by CO_2 regulations. The rule should be modified to require new units serving generators with a nameplate capacity less than 25 MWe to obtain emissions allowances. We suggest the threshold for new generators be set at 15 MWe or less. This is needed in order to send CO_2 regulatory and price signals to a broader pool of new generators and to prevent gaming that would undermine the regulation's CO_2 reduction goals and that would be unfair to existing generators. Within the RGGI region, there are recent proposals for multiple generation fossil fuel-fired units each just below the 25 MWe compliance threshold. Since economic efficiencies and operating efficiencies would ordinarily support larger units, the sizing appears to be driven by a desire to emit CO_2 without limits, thereby undercutting public health and the goals of the regulation. Since it is essential to reduce future emissions, there is no reason to encourage new generation that emits CO_2. With coverage of new units, the rule would better protect the public from CO_2 and co-pollutants, remove an incentive for building less efficient fossil fuel generators, and protect the integrity of allowance markets. Since developers would have notice of the allowance requirement for new generation, no unfairness would result from imposing a lower size threshold for such generation. Units placed in service after January 1, 2019 would fairly be considered new.	consistent with the RGGI Model Rule. Current state regulation (9VAC5-20-70) prohibits circumvention of air quality requirements by constructing multiple facilities in a piecemeal fashion in order to avoid regulation. DEQ believes that the declining emissions cap will encourage the development of renewable energy and energy efficiency, not the construction of multiple smaller facilities which, as the commenter points out, are less efficient.
152. Virginia Chapter of the Sierra Club et al.	Allocations of conditional allowances is a pragmatic choice designed to implement tradable emissions allowances. However, recipients of economically-valuable conditional allowances should be encouraged to use that value to promote the carbon-reduction purposes of the rule, not to produce windfalls. The proposal presumes that utilities will utilize revenues received from the consignment-and-auction process for the benefit of customers, either through incremental investments in energy efficiency or zero-carbon generation or applying the revenues to reduce retail rates. While this seems to be a reasonable assumption in light of SCC regulation of utilities, it is not a guarantee. DEQ should monitor how the auction revenues are utilized and consider adjusting the method for allocating allowances if the revenues are	The commenter correctly asserts that the SCC regulates and monitors utilities in order to assure that customers are protected. It is unclear how additional reporting requirements would ensure that these goals are effected.

	not used to advance the purposes of the rule. Recipients of allowances should be required to report annually how the auction revenue funds were used, including whether they were passed through to retail customers, used to reduce CO_2 emissions, used for other corporate purposes, or retained as earnings. Generators in other RGGI states do not expect funding from the auctions, and Virginia companies should not get auction revenues unless they promote the purposes of the rule.	
153. Virginia Chapter of the Sierra Club et al.	We support consigning a portion of the conditional allowances to holders of public contracts with DMME for the abatement and control of CO_2. RGGI member states use a much larger share of their auction revenues for such purposes by supporting measures to increase energy efficiency or zero-carbon renewable energy within their borders. It is reasonable for Virginia to do so with at least part of the revenues from the consignment auction process. Nevertheless, 5% is a small starting point. Consideration should be given to reallocating conditional allowances from non-utility generators or utilities to public contractors for implementing energy efficiency and renewable energy, particularly if the covered generators do not invest their auction revenues to expand zero-carbon energy solutions in Virginia.	As discussed in comments 51 and 53, a 5% set-aside is a reasonable figure in the early stages of the program.
154. Virginia Chapter of the Sierra Club et al.	Dominion's Mt. Storm is a large coal-fired electric generating facility located in West Virginia that is included in Virginia retail rates and is dispatched through PJM. DEQ should consider inviting Dominion to include Mt. Storm as a CO_2 budget source subject to the program, provided that the arrangement does not violate any West Virginia CO_2 rule and is acceptable to RGGI. The plant is old and a substantial source of CO_2 and other pollutants. We are not aware of any barrier to Dominion's agreeing to subject this plant to Virginia's CO_2 program, which would affect PJM's economic dispatch of the plant, but not require any plant modifications or state permits. Dominion and its customers could benefit from phasing down Mt. Storm's operations and shifting CO_2 allowances to newer, cleaner facilities located in Virginia.	Unless and until West Virginia links to the RGGI program, it is unlikely that they would expect for Mt. Storm to submit to RGGI requirements.
155. Virginia Chapter of the Sierra Club et al.	The proposal wisely does not provide for creating offset allowances. Offset allowances would require large investments of Virginia's administrative resources to analyze, approve and enforce proposals. Nearly 30% of the RGGI Model Rule text is devoted to standards and procedures for evaluating, approving, and enforcing offset projects. That is not a burden that Virginia should take on, particularly since it may require physical and economic processes beyond those DEQ normally oversees. Further, the value of offsets is dubious. Even if they reduce CO_2 somewhere, offset schemes may not provide ancillary benefits from reducing power plant emissions of CO_2, including benefits from reducing co-pollutants. Indeed, offset projects may increase the danger that local pollution will increase as a result of	DEQ agrees with the commenter that implementing offsets is not desirable at this time; see the response to comment 26.

	purported CO_2 reductions at remote locations as has happened under California's program.	
156. Tenaska Virginia Partners, L.P.	DEQ projects annual CO_2 emissions from covered facilities to be 36.8 million tons in 2019. Under the 34 million ton alternative, a 7.6% reduction would be required in the first year of the program. If the more stringent 33 million base budget were used, a 10.3% reduction would be required. These are 2.5-3.5 times the proposed 3% annual cap decline in subsequent years. Tenaska strongly suggests DEQ consider a higher base budget, such as 35 million tons, in the event the 2019 emission projection is proven accurate. At the very minimum, 34 million tons should be used. Tenaska strongly favors the "generation updating" approach, whereby covered facilities are allocated allowances according to their respective historical annual net generation as compared to the total aggregate generation from covered facilities, averaged over the immediate 3 calendar years, updated annually (i.e., on a rolling 3-year average). Tenaska believes this approach best meets the intent of the regulation, in that it incentivizes more efficient units that emit less CO_2 per unit of power produced. Note that Regulatory Advisory Panel (RAP) participants favored this option. As presented during RAP meetings, Tenaska's Virginia Generating Station in Fluvanna County currently operates under a long-term contract or "tolling agreement" with a third party, whereby the third party procures the fuel and purchases the generated electricity. The term of the agreement is 20 years and expires in May 2024. Under the terms of the agreement, Tenaska believes it has the ability to pass through to its customer costs for things such as emissions allowances, whether they be for the Acid Rain Program, CSAPR, or any future carbon trading scheme. However, Tenaska's customer has taken the position that Tenaska does not have such a pass through right. These costs are projected to be $2.30/MWh in 2020 and $3.78/MWh in 2031, representing an increase of 14.6-18.9% over the projected wholesale power price. To the extent Tenaska is required to purchase allowances and is unable to pass through those costs to its customer, it will be disadvantaged compared to other generators that can either recoup those costs or that have no costs due to their location in another PJM state without a carbon pricing scheme (e.g., Pennsylvania and West Virginia). Several RGGI states and every major proposed federal CO_2 cap and trade legislation has recognized this predicament and provided various forms of relief, such as creating an allowance set-aside for free allocations or offering allowances at a reduced price. Tenaska requests DEQ also recognize this and either create a	See response to comment 37 for a discussion of how the final base cap was determined. DEQ is assisting affected sources in meeting compliance costs by issuing allowances. The amount of compliance costs covered by the allowances will depend on business decisions made by any individual facility. If a facility stays within the budget, it will not incur costs.

	set-aside sufficient to cover net allowance obligations for LTC holders or simply exempt LTC holders for the life of the applicable contracts. The set-aside would be less disruptive to the program as it would alleviate units entering and exiting.	
157. Tenaska Virginia Partners, L.P.	We encourage DEQ to expand the scope of the regulation to include additional sources and seek meaningful reductions in other sectors of the economy (via alternative pathways), including mobile sources, if the dire consequences referenced are to be avoided. One such way is to remove the exemption in 9VAC5-140-6040 B for units that generate electricity and heat "for the primary use of operation of the facility." CO_2 emissions from such facilities are no less potentially harmful than those from units that generate electricity for off-site use. Neither the RGGI Model Rule nor the environment make such a distinction and neither should DEQ.	As discussed in the response to comment 65, this exemption is appropriate. While DEQ agrees that other pathways to CO_2 reductions are important, the scope of the regulation is limited by executive order and state law. DEQ believes that the 5% DMME set-aside as well as other ongoing programs such as the Grid Transformation and Security Act of 2018 will provide additional incentives for energy efficiency and renewable energy.
158. U.S. Green Building Council (USGBC)	We agree with the proposal to link Virginia with RGGI, creating opportunities for cost and resource reduction. DEQ should reconsider the 2020 emissions baseline to ensure it meets the objective of capping emissions. The 33 million ton baseline is higher than the 2017 carbon emissions of 31.2 million tons, while energy productivity is increasing. These data suggest that a lower baseline will be more successful at driving reductions. Subsequent to DEQ projections, the General Assembly passed SB966, which could affect the baseline generation from fossil fuel power plants and their carbon emissions. We recommend increasing the 5% set aside. Such set-aside funds are critical to expand DMME programs, which for some sectors are the primary potential source of energy efficiency assistance given SCC limitations on efficiency programs. The majority of the set aside should directly benefit low and moderate income persons and areas. It is well established that disadvantaged populations are disproportionately impacted by air pollution. Moreover, programs aimed at increased efficiency in low and moderate households have a co-benefit of reducing their vulnerability to electricity rate increases. The regulation should provide for DMME to actively seek public input on use of the set aside including how the proposed use benefits target populations. DMME and DEQ should study and monitor potential impacts of the regulation on low and moderate income households, and periodically report findings to the public.	See comment 37 for a discussion of how the final base cap was determined. As discussed in the responses to comments 51 and 53, a 5% set-aside is appropriate in the early stages of the program. The specifics of how this set-aside will be managed will be determined by DMME. DEQ agrees that vulnerable communities must be addressed, and the program contains multiple opportunities to do so; see the response to comment 55 for more information.

159. Environmental and Regulatory Law Clinic, University of Virginia	Given the climate change-related threats facing our state--and considering the sources of pollution in Virginia that contribute directly to those threats--it is entirely appropriate and necessary for the board to initiate a regulatory program linking Virginia to RGGI. The Office of the Attorney General issued an official advisory opinion that analyzed the relevant statutory and administrative authority and concluded "that the State Air Pollution Control Board is legally authorized to regulate GHG emissions." Specifically, the Attorney General noted that the board is authorized to regulate "air pollution" in the state, and observed that GHGs unquestionably fall within the definition of "air pollution." The Attorney General further concluded that because of its "broad statutory authority" under Va. Code § 10.1-1307(A), the board can exercise its regulatory authority through imposition of a "statewide cap on GHG emissions." The board also has the authority to maximize the efficiency and efficacy of a statewide cap by linking the program with RGGI. A state-led program is not preempted by the federal Clean Air Act, and is, in fact, specifically authorized by the Clean Air Act's state law savings clause (42 USC § 7416).	Support for the proposal is appreciated. DEQ agrees that the board and department have the legal authority to develop the proposed regulation; see the response to comment 76 and, for example, comment 139.
160. Virginia Loggers Association (VLA)	Virginia's land cover is approximately 62% forested; in total, 15.8 million acres of forest with about 12.2 million acres are owned by private individuals, corporate and non-profit organizations. The majority of Virginia's forests are owned by individuals. Timber production is an important part of Virginia's economy and environment. The most recent study released by Governor McAuliffe shows that our forest products industry is the third largest contributor to Virginia's economy. The study revealed that almost $9.3 billion were added directly due to forests. Most of these forests are managed through the most current science enabling our forests to be productive for timber products and environmental benefits. Our forests are healthy and have increased in volume since inventory studies in 1940s. Virginia's forests are growing at a faster rate than harvest removal and mortality. The latest inventory shows that softwood annual growth to annual harvest is at a ratio of 2.2:1 and hardwood annual growth to annual harvest is 2.4:1. Our forests clean the air, sequester carbon, and improve water quality, wildlife habitat and recreational opportunities while producing products for many. Biomass is an important component of Virginia's energy policy. Many of our members invested millions of dollars in equipment to provide biomass to utilities across Virginia. We ask that any regulation recognize the investments made by our mills and logging businesses as well as the renewable natural qualities of forests. Some areas of the proposal would require our mills to invest further for monitoring biomass sources currently not required. We ask that you remove any additional requirements on biomass based sources. Continue to	The commenter's concerns are appreciated. See the responses to comments 65 and 67 for further detail.

	treat biomass as carbon neutral. Finally, we ask that DEQ maintain the current exemption of industrial boilers.	
161. Virginia Energy Efficiency Council (VAEEC)	Energy efficiency is one of the most cost-effective tools to reduce energy consumption and dependence on fossil fuels, which in turn helps reduce carbon emissions. We applaud the inclusion of the 5% set aside for energy efficiency programs. Expanding energy efficiency provides Virginia residents with affordable energy bills and healthier, more comfortable homes. Last year, the American Council for an Energy-Efficient Economy (ACEEE) listed Virginia as one of the most improved states in their 2017 State Energy Efficiency Scorecard. Moving from 33rd to 29th place underscores the work VAEEC, our members and our partners have done to advance energy efficiency policies and initiatives. But there is more that can be done to help Virginia break into the top 25. The passage of the Grid Transformation and Security Act paves the way for greater opportunities as well. These programs, in addition to the energy efficiency carve out will propel Virginia into the spotlight as a leader on energy efficiency.	Support for the proposal is appreciated. DEQ agrees that energy efficiency is an essential component of reducing carbon emissions.
162. Virginia Coal and Energy Alliance (VCEA)	The benefits provided by the coal and coal-related industries should only be placed at risk if the justification for doing so is clear--that is, if the benefits from the burden placed on those industries are greater than the benefits they provide. Unfortunately, the justification provided for the CO_2 Trading Rule is anything but clear, as it unfairly compares an underestimated assessment of real-world local costs and economic impacts to a theoretical and now-rejected overestimate of global benefits. The justification proffered for the proposal contains a logical disconnect. The justification, which is based on the Report of the EO 57 Work Group, proceeds as follows: 1) climate change causes certain harms in Virginia (e.g., heavy storms, water shortages, and warmer temperatures); 2) therefore, reducing the GHG emissions in Virginia will reduce those harms and benefit Virginia. However, that assumes that reducing CO_2 emissions will address harms here. Contrary to that assumption, reducing emissions in Virginia will not have any impact on the earth's climate. Emissions from Virginia--indeed, the entire U.S.--are such a small portion of total global emissions that any reductions are almost certain to have no meaningful effect. The benefits alleged in support of the rule are based almost entirely on the "social cost of carbon," a metric crafted by a disbanded interagency working group under the Obama Administration. The Trump Administration has rejected that metric and directed that it no longer be used to justify federal regulations. The social cost of carbon analysis admits a critical point: "[e]ven if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid	The board is within its legal authority to address carbon pollution, which poses serious threats to the Commonwealth, through a cap-and-trade program; see the responses to comments 61 and 76.

	substantial climate change." That confirms that even those in favor of climate change policies must recognize that the reductions from any one country, much less any one region or state, will not change anything. The social cost of carbon itself is flawed because it relies on a highly speculative evaluation of global benefits, followed by an unfair comparison of those worldwide benefits to domestic costs incurred within the U.S. alone. Not only is that comparison unreasonable, since worldwide benefits will always dwarf the costs incurred by a single nation, it also represents a break from the manner in which the impact of regulations has always been evaluated. U.S. costs have always been compared to U.S. benefits in order to provide a fair basis for the comparison, even for regulations that may benefit other countries. With the withdrawal of the social cost of carbon from federal policy, federal agencies must now return to that more reasonable and well-understood approach, and DEQ should do the same. The other justification relies on co-benefits associated with reductions in other pollutants, such as NO_X, SO_2, and particulate matter, which can directly impact human health (unlike CO_2). Co-benefits are not a reasonable basis upon which to justify the rule because the other pollutants are already well controlled by other Clean Air Act programs. Only a small portion of the state is nonattainment for ozone, due to its proximity to the D.C. metropolitan area, not emission sources located in Virginia, and sufficient rules are in place to address those air quality concerns. The rest of the state complies with EPA standards set to protect public health, and no further reductions are needed to maintain compliance with those standards. Claiming that reductions in other pollutants as a justification amounts to double-counting of air quality benefits already achieved and paid for. Although the rule would adopt a seemingly small 3% per year reduction, those compounding reductions will be more significant than the analysis suggests because it ignores and essentially prohibits growth in emissions that would otherwise occur. Whereas the supporting analysis claims a reduction of 30% (from 33-34 million tons in 2020 to 23-24 million tons in 2031), in effect it will actually require reductions of nearly 50% when compared to what would otherwise occur without the program (40-50 million tons). The result will be an increase in the cost of electricity of over 7% and present a significant burden on the coal and coal-related industries. The assertion that emission reductions of a similar magnitude under the proposed rule will have only a minimal impact on the economy of the state is difficult to believe.	

	To combat concerns about the impacts to the economy and the cost of electricity, an analysis was prepared to focus on individual utility bills. The conclusion of that study suggests that the impact to ratepayers will be minimal. However, if that is in fact the case, it must mean the analysis assumes the regulation will not significantly affect the market; that is, the study must have assumed that the market itself would likely encourage nearly the same emission-reducing behavior based solely on the demand for and supply of energy. But if that is true, then the regulation would not be responsible for any of the emission reduction benefits claimed. The supporters of the proposal cannot have it both ways--either the program will require reductions that would not otherwise occur under existing market forces, in which case significant costs will be incurred in working against the market, or else the market would already encourage the reductions now sought via regulation, in which case the regulation is unnecessary. The General Assembly has already decided that the CO_2 Trading Rule is not in the best interest of Virginia and passed HB1270 to prohibit the very type of program contemplated by the proposal. The Governor vetoed the law and is charging ahead via executive fiat to establish such a program. This scenario is similar to what has transpired at the federal level. Despite the fact that Congress rejected efforts over more than a decade to enact a climate trading program, the Obama Administration decided to establish one through executive authority by issuing the Clean Power Plan, which was based on a few ambiguous and general sentences of the Clean Air Act. So too here, given that the authority claimed by the Attorney General as the basis of the regulation is merely the general authority "to promulgate regulations, including emergency regulations, abating, controlling and prohibiting air pollution." Legislatures grant bold powers in clear terms, and executive agencies should not try to invent bold powers out of ambiguous language. This principle should have equal effect at the federal and state levels, since both governments are based on the same fundamental principle: the legislative branch makes the laws, and the executive branch wields only the authority granted to it by the legislature. Nothing in the Clean Air Act clearly authorized EPA to issue the Clean Power Plan, and that is likely why the Supreme Court stayed it. Those same concerns appear relevant to the proposal, but perhaps to an even greater extent. Unlike Congress, which has been unable to pass a climate change bill, the Virginia legislature did pass one, but one that prohibits what the executive branch is now trying to do on its own. That executive action is only legal if the legislature has	

	already authorized such a program in a previous statute, but it did no such thing. Rather, the statute claimed to be the underlying authority for the regulation is the same type of highly general authority found in the Clean Air Act. Such general grants of authority to issue regulations to address air pollution provide no clear authority for the policy shift the Governor seeks to implement, which represents a decision of economic and political significance. The Governor should not invent that authority, particularly in light of the statement to the contrary recently made by the legislature.	
163. Virginia Conservation Network (VCN); Virginia League of Conservation Voters (VaLCV)	VCN and VaLCV encourage DEQ to select an emissions baseline that best achieves the goals of reducing statewide carbon pollution. This baseline should be the most stringent, lowest possible science-based figure supported by modeling. For additional details on the stringency of the carbon program, as well as modeling results, please see the technical comments from our partners at NRDC, Sierra Club, and SELC. We are thankful that the regulation covers both current and future fossil fuel-fired units. We were glad to see the inclusion of co-firing units that include at least one fossil fuel-fired unit; however, it should include all electric power facilitates that emit carbon, regardless of fuel type. Specifically, the regulation should apply to any unit at or above 25 MW that burns biomass. For additional details on biomass, please refer to the comments submitted by the National Wildlife Federation. We appreciate and support the 5% set aside of allowances to assist DMME in efforts to address carbon emissions. We encourage DEQ to consider increasing this to 10%, with the understanding the benefits of increasing this figure should be greater than the costs associated for covered sources.	Support for the proposal is appreciated. The commenters' specific issues are discussed elsewhere. See the response to comment 37 for a discussion of the baseline emissions cap, comment 67 for a discussion of biomass, and comment 51 for set-asides.
164. Veolia North America	We commend DEQ for exempting certain industrial combined heat and power (CHP) units from the regulation. CHP plays an important role in the state's clean energy and resilience goals and merits additional support. CHP units deserve special treatment as they have been designed to optimize the efficient production of heat and power for industrial facilities. While the exemption sets a positive policy direction, it needs to be modified to ensure that it rightfully applies to all relevant industrial CHP units. The exemption only contemplates the CHP unit being owned by the industrial end user rather than by a third party. This is counter to the trend of more industrial end users moving to outsource ownership, operation and maintenance of their central utilities. In this model, the industrial company can focus on executing its core business while relying on a specialized third party whose core business is owning, operating and maintaining industrial utilities on a safe, cost effective and reliable basis. As such, the ownership status of the CHP unit is	DEQ agrees that the phrase "owned by an individual facility" should be removed. Under the RGGI Model Rule, facilities that provide less than 10% of their power output to the grid are exempted from compliance obligations; the proposal has been revised accordingly. The regulation has also been amended in order to address CHPs with more clarity; see the response to comment 74.

	not relevant to the key issue: does the CHP exist to primarily provide service to the industrial end user? Relying on "primary use" intent, rather than regulating CHP ownership, would better focus the regulation on GHG reduction while also allowing the industrial and manufacturing sector in Virginia greater flexibility to achieve this regulatory purpose. We suggest that DEQ remove the phrase "owned by an individual facility and" from the industrial exemption. To qualify for the exemption the useful energy output (thermal and electric) of a CHP needs to be "for the primary use of operation of the facility"; however, "primary use" is not defined. We urge DEQ to clarify the meaning of primary use by considering the magnitude of a CHP's generation of useful thermal energy (UTE) relative to useful electrical energy and by the application of an appropriate CHP efficiency standard. One of CHP's benefits is that it can produce both UTE and electricity from a single fuel source. It is not uncommon for a host to have a high need for thermal energy and a low need for electricity. In order to efficiently service an industrial facility's steam load, a CHP unit may need to be designed in a way that exports a substantial portion of its electric power to the grid. The need to export to the grid is important in circumstances where utility franchise rights prevent third party CHP facilities from delivering power to industrial sites. The integrity of the industrial exemption will be maintained if the focus is on UTE. The industrial exemption can be strengthened by adding an efficiency requirement. This will provide CHP units incentive to maximize requirements of its host rather than exports to the electrical grid. The Virginia legislature recognized the need to encourage CHP systems in the Grid Transformation and Security Act, which requires that the total efficiency, including the use of thermal energy, for eligible CHP facilities meet or exceed 65% (Lower Heating Value) annually. A similar requirement for the industrial exemption would ensure consistency. Veolia recognizes the concept of tying the industrial exemption to a unit "voluntarily restricting its electrical output to the grid (through permit condition) to less than or equal to 10% of the units annual gross generation of the unit." This approach too narrowly restricts what industrial facilities can do with electric generation and conflicts with the broader intent of primary use. Recognizing that not all CHP units will qualify for the exemption, but acknowledging that these units still deliver valuable GHG reductions, we recommend a UTE exemption. CHP units over 25 MW that do not qualify for the industrial exemption, must procure CO_2 allowances for all emissions, including those associated with UTE (i.e., microgrid, district energy, process steam, hot	

	water). Absent production at a CHP unit, the UTE would be produced by conventional methods, such as standalone boilers. These conventional methods of generating UTE are not subject to the regulation, and thermal generation-only unit owners are not required to procure CO_2 emissions allowances. If CHP units over 25 MW are required to procure CO_2 allowances for all emissions, including those associated with UTE, it will create a counterincentive and potentially increase GHG emissions. To avoid this, the regulation should exclude CO_2 emissions associated with UTE from a CHP unit. When determining the RGGI emissions allowance compliance obligation for a CHP unit, emissions associated with UTE of that unit should be deducted from the unit's total emissions. There is precedent for adopting a UTE exemption based on existing UTEs in federal and state agency carbon trading programs. EPA's Clean Power Plan included a UTE exemption for CHPs. Several RGGI states have adopted a UTE exemption in different forms. For example, Massachusetts has an exemption for any CHP CO_2 budget source that allows the CHP unit to subtract from its total CO_2 emissions the amount of CO_2 emissions attributable to the production of useful net thermal energy. The Massachusetts regulation acknowledges that, absent production in a cogeneration unit, UTE would be produced in a standalone boiler. These boilers do not have a compliance obligation under any RGGI program, and have no mandated efficiency targets. With this UTE exemption structure, a generation unit has an incentive to maximize useful outlets for its waste heat. The Massachusetts UTE exemption is the most effective and straightforward approach, and we encourage DEQ to adopt a similar exemption. Under this approach, emissions associated with UTE are calculated on a formulaic basis and are subtracted from a CHP's compliance obligation. Note that the exemption is only for emissions associated with UTE. CHP units that fall under RGGI will still be required to procure allowances for any emissions not associated with UTE. However, with the UTE exemption, CHP will be on equal footing with conventional generators whose only output is electricity. By reducing a unit's environmental compliance costs, the UTE exemption removes a potential barrier for investment in CHP. The ability for a CHP unit to exclude emissions from UTE from its compliance obligation will become even more important in the future. With the RGGI emissions cap declining each year, it is likely that RGGI allowance prices will continue to increase. As RGGI allowance prices increase, they will drive up compliance costs and increase the economic disincentive faced by CHP units. Without a UTE exemption, there will be a similar adverse	

	effect on existing facilities that have the option of using CHP to generate UTE or using stand-alone boilers. As the costs of CHP rise due to higher RGGI compliance costs, the dispatch of equipment may change resulting in more standalone generation of UTE and higher regional carbon emissions.	
165. Virginia Forest Products Association (VFPA)	VFPA does not support joining RGGI because it would raise electric power and natural gas rates. This is a grave concern to our small businesses, as even small sawmills without kilns have electric bills that average $6,000/ month. Kiln dryers add substantially to that monthly bill, and larger mills with kilns have monthly electric bills in excess of $20,000. Our primary competition is in North Carolina, not the RGGI states, and an increase in our utility rates will put us at a competitive disadvantage. A more critical concern is the potential impact if emissions from the combustion of biomass are treated as GHG. Lumber production produces manufacturing residuals in the form of mulch, sawdust and chips. Even a small mill can produce 25 tons per day of dust and chips each. There is a ready supply of wood residuals from sawmills in the state that require a variety of markets. Having ready outlets to dispose of residuals is critical; we can't saw lumber if we can't move residuals off the yard. We are extremely concerned that disincentivizing the burning of biomass for power could negatively impact sawmills, loggers, and landowners by reducing or eliminating that market. The boiler fuel outlet for residuals is key to our survival; if it is treated the same as any other fossil fuel but costs more for the utility to procure, they will no doubt select the less expensive option since the benefit is removed. The science on the carbon neutrality of woody biomass is solid, and VFPA supports the comments and supporting data submitted by AF&PA and AWC. Harvesting wood for energy does not contribute to net carbon emissions in cases where the harvesting, measured over a broad region, is offset by wood growth and associated carbon sequestration. The most recent data from the U.S. Forest Service indicate that timberlands in Virginia, the U.S. south, and the entire country have highly positive net growth/removal ratios. The Virginia Department of Forestry's Reforestation of Timberlands Program has reforested 1.8 million acres since the program's inception. This program provides cost-share assistance to landowners in planting, replanting, and managing forest acreage. Since 1970, landowners and industry have reforested 4 million total acres in Virginia. U.S. Forest Service data from 2016 shows growth/removal ratios for timberlands in Virginia, the U.S. South, and the nation as a whole are 2.29, 1.76, and 1.94, respectively. In other words, Virginia's	The commenter's concerns are recognized. See the response to comment 67 for a discussion of biomass. The industrial exemption will be maintained; see the response to comment 65.

	timberlands are growing more than twice as much wood as harvested, while timberlands in the south grow 76% more than is harvested. When environmental organizations cite the cutting of trees by the forest product industry as inherently negative, they ignore the cyclical nature of managed timberlands. The most significant pressure on forests is permanent conversion to non-forest uses, such as development. However, strong markets for wood are the most powerful incentive to keep forests in production. From the sawmills' perspective, markets for the finished product and residuals on the back end are as important as the supply of trees on the front end. A balance in supply and demand will keep businesses and forests healthy. A 2014 article in the Journal of Forestry noted that if mill residues were not used for energy, most of these materials would be wastes that would either be incinerated, in which case the atmosphere would see the same CO_2 emissions as if the material had been burned for energy, or disposed of in landfills. The article further states that the net impact of burning for energy on biogenic emissions in terms of warming can be less than zero because of the warming potency of methane generated in landfills. In the past, many sawmills burned wastes on site in large incinerators as there were not enough markets for the materials. Residuals build up quickly in the process of sawing lumber. If today's mills lose too many markets for residuals, the financial burdens of incinerating on site or the costs of landfill tipping fees for disposal of thousands of tons of residuals would force many sawmills to cease operation. From economic and environmental perspectives, treating biomass as carbon neutral in energy production makes dollars and sense. VFPA respectfully requests that Virginia not join RGGI. However, if the state does join RGGI, we ask that biogenic carbon emissions be recognized as carbon neutral regardless of whether other fuels also are co-fired; and that the exemption for industrial boilers be retained. This regulation is designed to address utility electrical generation only; the exemption for on-site industrial generation should remain in the final rule. This is also important because of potential market impacts to saw mills if large industrial users lose this incentive for firing with biomass.	
166. Virginia Chamber of Commerce	The Virginia Chamber recently released Blueprint Virginia 2025, a plan that outlines the business community's priorities and recommendations for making Virginia the best state for business. Throughout our stakeholder engagement process, which included over 6,000 members of the business community, we heard from business leaders on how important affordable, reliable energy is to Virginia's economic competitiveness.	The regulation is designed to impose regulatory requirements only as strictly necessary in order to participate in the highly successful RGGI program without affecting economic competitiveness. As

	Energy affordability was identified by 55% of Blueprint survey respondents as their top energy concern. Unfortunately, RGGI is not consistent with the Chamber and Governor's goal to make Virginia the best state for business, as it will increase electricity rates and make Virginia less competitive. The Chamber supports policies that promote energy independence and the development of a robust supply of energy. We advocate an energy portfolio that promotes economic development and job growth through traditional and alternative energy investments, and believe that environmental protection and energy independence are compatible goals. It is expected that energy consumption in Virginia will continue to rise, reflecting the increase in population, economic growth, and electrification of the transportation system . To ensure a growing economy, we must develop strategies for an ample supply of affordable and reliable energy. Part of achieving our goal of being the best state for business is to protect our competitive rates for electricity. Business climate rankings factor energy and utility costs into their "cost of doing business index," which can influence our overall position. Favorable energy costs are important in order to remain economically competitive. By joining RGGI or initiating a cap-and-trade program, energy costs for employers and residents will rise. According to a recent Cato Institute study, the RGGI program creates higher electric bills and shifts jobs to non-RGGI states. According to the U.S. Chamber of Commerce's Global Energy Institute, the average electricity rate of the RGGI states is 39% higher than the national average. By contrast, Virginia has the nation's 19th lowest average electricity rates, 12% cheaper than the national average. Virginia's affordable rate provides the state a competitive advantage when it comes to attracting manufacturing and other energy intensive industries, such as high-tech data centers. Any program that would increase electricity rates--such as RGGI--would reduce this competitive advantage. Further exacerbating the negative effects to our economic competitiveness is the problem of carbon leakage. The state's own modeling illustrates the potential impacts of leakage that could result from partnering with RGGI. Participating in RGGI is likely to increase electricity imports into the state. Because many of the neighboring states in the PJM electricity region do not participate in RGGI but are powered by resources with a higher carbon intensity, shifting generation from Virginia into these states may result in an increase in emissions. Under this scenario, Virginia suffers the economic consequences of joining RGGI while achieving no progress toward its environmental goals.	discussed elsewhere, the regulation retains exemptions for certain industrial and biomass facilities, and provides for free allowances. Note that RGGI's "CO_2 Emissions from Electric Generation and Imports in the Regional Greenhouse Gas Initiative: 2015 Monitoring Report" demonstrates that carbon emissions in the RGGI are decreasing in intensity; essentially, carbon intensity is being decoupled from electricity generation. See, for example, the response to comment 61. The regulation has been carefully designed to be least restrictive to Virginia business, does not hurt the state's economic competitiveness, retains an industrial exemption, exempts certain forms of biomass, and provides for free allowances.

	While RGGI backers cite the program as a successful cap and trade model, there is little evidence to suggest that the program has been effective at reducing emissions. The Agency Background Document states that a primary advantage to the public of joining RGGI would be "health and welfare benefits associated with controlling carbon pollution." In the Economic Impact Analysis, DPB estimates that the benefits of the state's effort to reduce CO_2 would be between $42-50 million annually between 2021-30. Note that the social costs of carbon are controversial and uncertain, based on long-term assumptions about the damages that may result from increased carbon emissions. As DPB notes, the $42-50 million of CO_2 reduction benefits are global, not Virginia-specific. DPB states that it is "not possible to quantify the Virginia-specific benefits," but this is not accurate; a number of analysts employ the use of "equity weighting" as a means to compare impacts to different regions. EPA and other federal agencies now use this method to develop domestic-only estimates of the social cost of carbon (SC-CO_2). We can estimate the benefits to Virginia similarly. When applied to calculate a Virginia-specific benefit, the mid-range of OPB's estimate of $46 million in SC-$CO_2$ benefits is reduced to a mere $250,000. This is because, at the mid-range of the program (2025), U.S. GDP is projected to be 20.5% of global GDP, and Virginia GDP is 2.7% of U.S. GDP ($46 million X .205 X .027 = $250,000). Divided by Virginia's estimated reductions of 1 million tons per year, this equates to a benefit to Virginia of 25 cents per ton of CO_2 reduction. Viewed in this Virginia-specific manner, it is difficult to see how the program's costs justify its projected benefits. If Virginia does move forward with this proposal, we ask that the regulation be least restrictive to Virginia businesses, does not hurt the state's economic competitiveness, retains an industrial exemption, treats biomass as carbon neutral, and provides for free allowances as opposed to an auction.	
167. Virginia Housing Alliance	We recommend that the 5% allocation be used for energy efficiency services for renters in multifamily housing. Energy efficiency in multifamily housing can help Virginia meet the state's voluntary goal to reduce electricity consumption for commercial and residential buildings by an amount equal to 10% of 2006 consumption by 2020 in addition to reducing carbon pollution for compliance with ED 11. If used for energy efficiency, the allocation will reduce energy use and carbon emissions, reduce the need for added electric generation, improve public health and environmental quality, boost job creation, and preserve affordable housing. We support Virginia's entrance into RGGI and hope that energy efficiency will be regarded as a	DEQ recognizes the value of energy efficiency in multifamily housing as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement renewable energy and energy

	necessary and cost effective tool for Virginia's transition to a clean energy future.	efficiency programs. DMME may, at the appropriate time and in accordance with its regulations and policies, implement a set-aside for energy efficiency in multifamily housing. See the response to comment 51 for more information.
168. WestRock; Covington, Hopewell and West Point mills	While WestRock generates a considerable portion of its own energy at our largest manufacturing facilities, having access to sufficient quantities of utility-provided electricity at reasonable prices is critical for reliability and economic reasons. Some of our mills are entirely energy independent, but others must purchase a significant portion of their electricity from the grid. Our converting operations in Virginia rely heavily on purchased electricity. West Rock spends over $100 million annually on energy in Virginia. As a large electricity consumer in the state that also uses considerable amounts of biomass for energy generation, WestRock will be substantially affected by the proposed rule. We are a member of AF&PA and NCASI, and support the comments submitted by these organizations.	The commenters' concerns are acknowledged. See the responses to comments 65 and 67.
169. WestRock; Covington, Hopewell and West Point mills	The proposed rule states that if biomass comprises 90% or more of the total heat input to an electric generating unit, the unit and its biogenic CO_2 emissions are not regulated. However, if biomass comprises less than 90% of the heat input to an electric generating unit, biogenic CO_2 emissions are regulated and allowances must be remitted for CO_2 emissions from that unit. This treatment of biogenic CO_2 emissions is arbitrary and capricious. Biomass carbon neutrality does not change based on the amount of biomass fired, nor does it change when biomass is co-fired with other fuels. The treatment of CO_2 emissions from the combustion of biomass represents a significant departure from current U.S. federal law, internationally-accepted carbon accounting protocols, and the RGGI model rule. The carbon benefits of biomass are best understood in the context of the entire carbon cycle. As forests grow, CO_2 is removed from the atmosphere through photosynthesis. This CO_2 is converted into organic carbon and stored in woody biomass. Trees release the stored carbon when they die and decay or are combusted. As the biomass releases carbon in the form of CO_2, the carbon cycle is completed. The carbon in biomass will return to the atmosphere regardless of whether it is burned to produce energy, allowed to biodegrade, or lost in a forest fire. Overall, the flow of forest CO_2 is carbon positive when forests are sustainably managed and the forest system remains a net sink of CO_2 from the atmosphere. Carbon stock accounting shows that carbon storage in U.S. forests is	The commenters' discussion of biomass and forest lands is appreciated. As discussed in the response to comment 67, certain biomass facilities will not be subject to the program. RGGI states allow CO_2 budget units that co-fire eligible biomass to deduct CO_2 emissions attributable to the burning of eligible biomass from their compliance obligation in accordance with the RGGI model rule. The regulation has been amended in order to address CHPs with more clarity; see the response to comment 74.

	positive and currently offsets about 12% of total U.S. CO_2 emissions annually. In Virginia, the growth of the state's forests offsets about 14% of the total annual CO_2 emissions. In 2014, the ratio of the forest's annual growth compared to harvest volume was more than 2.1:1 for softwood and 2.2:1 for hardwood. This amounts to an annual surplus of 8.4 million tons of softwood and 14 million tons of hardwood. Biomass residuals from the manufacturing process are used as the primary fuel to power paper mills. If these residuals are landfilled instead of being used as fuel, they would release GHG to the atmosphere, increasing emissions of methane, which has a global warming potential 25 times higher than CO_2. In addition to utilizing residuals, more than 97% of electricity produced by pulp and paper mills is generated through the use of highly efficient CHP. CHP provides energy efficiencies in the range of 50% to 80% at forest products mills. In the 2018 Consolidated Appropriations Act, Congress directs EPA, DOE, and USDA to ensure that federal policy relating to forest bioenergy is consistent across all federal agencies and recognizes the benefits of forest biomass for energy, conservation, and responsible forest management. Several states also have laws recognizing the carbon neutrality of biomass, including Washington and California, and RGGI itself states: "CO_2 emissions from eligible biomass reduce the total CO_2 allowance compliance obligation of the emitting unit. Emissions from eligible biomass should be deducted from the regional total of CO_2 emissions for purposes of calculating emissions from CO_2 budget sources subject to RGGI CO_2 allowance compliance obligations." Biomass CO_2 emissions are either not reported or reported separately or for information purposes in many domestic and international GHG regulations and protocols, including the World Resources Institute/World Business Council for Sustainable Development, and the U.N. Intergovernmental Panel on Climate Change. The board seeks comment on the potential impacts of the rule on forest land preservation. Studies show that recognizing the carbon neutrality of biomass will not negatively impact forest inventories due to the availability of lower cost renewable fuel options. In one such study, the Energy Information Administration (EIA) modeled the potential impact of the Clean Power Plan on the use of biomass for energy generation. In all EIA scenarios, co-firing biomass was projected to decrease under the CPP. In the long term, biomass is not a strategic, large scale, cost-effective alternative to fossil fuel. EIA modeling shows that standalone biomass energy plants are not considered cost competitive. In a recent article, EIA discusses the costs of various electricity generation technologies. The article shows that by 2022, onshore	

	wind will have a lower levelized cost than biomass in all U.S. regions, and solar photovoltaic will be less costly than biomass in some regions. Subsidies will tend to make solar and wind even more competitive. Studies also show that demand for biomass helps prevent forest land from being converted to other uses. A Department of State report shows that demand for forest products will increase forest carbon stocks through landowner investment. Markets for biomass and other forest products stimulate forestland ownership and encourage investment in healthy forest management practices. Farmers and forest owners, as with all business owners, respond to markets and produce more when demand increases. The most significant deforestation threat in the U.S. is forest conversion. Current forest inventories and the net sink are subject to the protections of a state law that caps the amount of biomass that Virginia utilities may use for energy under the Renewable Portfolio Standards program. Virginia Code 23 VAC 56-585.2 states: "Utilities participating in such program shall collectively, either through the installation of new generating facilities, through retrofit of existing facilities or through purchases of electricity from new facilities located in Virginia, use or cause to be used no more than a total of 1.5 million tons per year of green wood chips, bark, sawdust, a tree or any portion of a tree which is used or can be used for lumber and pulp manufacturing by facilities located in Virginia, towards meeting RPS goals, excluding such fuel used at electric generating facilities using wood as fuel prior to January 1, 2007." To the extent the regulation requires the monitoring and reporting of GHG emissions, WestRock urges the board to allow covered facilities to separately calculate and report biogenic and fossil fuel CO_2 emissions as is currently allowed under various established GHG reporting protocols.	
170. WestRock; Covington, Hopewell and West Point mills	The proposal excludes industrial sources from coverage, and WestRock supports this. EO 57 and ED 11, the authorities upon which the proposal is based, limit the scope of the rulemaking to the electric power generation sector. ED 11 states that the DEQ Director shall, in coordination with the Secretary of Natural Resources, "develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit CO_2 from electric power facilities." EO 57 is similar. These directives manifest a clear intention to exclude industrial sources. Neither the Economic Impact Assessment, the proposed emissions cap, nor the allowance allocation and price modeling conducted by DEQ and its consultants included emissions from industrial sources. Similarly, the charge given to the Regulatory Advisory Panel did not include industrial	The industrial exemption is discussed in the response to comment 65. Consistent with the RGGI model rule, the proposal has been amended to remove the phrase "owned by an individual facility" in order to ensure that facilities are not be penalized for employing more energy efficient and less polluting generating systems that may be operated by a third party on behalf of the primary facility. The

	sources. Inclusion of industrial sources is unnecessary and cannot be justified on a cost/benefit basis. According to EIA, industrial sources in Virginia emit 11.6 million tons of CO_2 and comprise 11 % of emissions in the state compared to 30% by the electric utility sector, and 43% by the transportation sector. EPA data indicates that GHG emissions from Virginia's industrial sector have decreased 31% since 2000. On the other hand, including industrial sources would cost Virginia businesses $18.9 to $41 million. The exemption is consistent with the intent and scope of the existing RGGI program, which does not regulate emissions from industrial sources. In fact, except for the purposes of reporting, there do not appear to be any industrial sources listed in the RGGI CO_2 Allowance Tracking System's list of regulated sources. Including industrial sources would not only put the state at odds with other RGGI participating states, it would put Virginia industry at a competitive disadvantage. RGGI allowance prices are based on the marginal cost to reduce GHG emissions from the utility sector and do not reflect the ability for industrial sources to reduce emissions. Subjecting industrial facilities to allowance markets that are not reflective of their own marginal costs would be unfair and poor public policy. The exemption should be clarified by adding the definition of electric generating unit found in VA Code 10.1-1328 to distinguish between industrial and electric power facilities as it relates to the term "primary use." Steam and electricity generation at an industrial facility is almost without exception for the primary use of the facility. However, actual flows of electricity may reflect buy-sell contractual arrangements or engineering constraints. It is not uncommon for an industrial CHP facility generating electricity to meet the primary needs of its operation, to export all that it generates and purchase 100% of its electricity needs. For the purposes of determining "primary use of the operation," it is imperative that net electricity flows be considered to ensure that industrial generation is not unintentionally included simply by virtue of contractual arrangements or the nature of its physical connection to the grid. Although WestRock owns its onsite CHP operations, in some cases CHP operations may not be owned by the facility where they are located due to financing arrangements. To promote the use of CHP, DEQ should remove the requirement that fossil fuel power generating unit located at an industrial facility also be owned by the facility.	regulation has been amended in order to address CHPs with more clarity; see the response to comment 74.
171. WestRock; Covington,	If the rule is promulgated, electricity costs in Virginia will rise. DEQ's economic analysis suggests that the impact of this cost increase will be no more 1.1% by 2031.	As discussed in the response to comment 91 and elsewhere, while

Hopewell and West Point mills	However, other studies suggest that the increase in electricity prices may be far more significant. According to a report cited by VMA in its comments, electricity costs in the RGGI states rose by 4.6% between 2007-15, which was 64% higher than the increase in electricity costs in a sampling of 5 non-RGGI states. Increases in the cost of electricity for large consumers like WestRock may make Virginia a less attractive place for investment than neighboring states without carbon reduction mandates. Increases in electricity costs may lead to the use of more imported electricity from areas without CO_2 reduction mandates, which may undermine any environmental improvements from the proposal. We encourage the retention of free allowances and a cap of 34 million tons (or higher), both of which may help moderate the cost of the program. WestRock, the industrial sector, and the utility sector have significantly reduced their GHG emissions through capital investment in more energy efficient energy generation, production processes and the use of lower carbon fuels. This trend is expected to continue both through ongoing capital investment and as part of the commitments made by WestRock and others to meet voluntary GHG reduction goals.	generation shifts are common in a regional electricity market, there are many reasons to believe that the trading program is unlikely to cause generation shifts and, if it does cause some shifting, reasons to doubt those shifts will lead to emissions leakage. The RGGI states have not found leakage to be a problem for the program in 10 years the program has operated. The program is quite modest relative to other cost factors in the regional electricity markets and any shifting is likely to substitute one gas plant for another, meaning the emissions consequences are not significant. The Virginia program includes an allowance allocation approach that will directly counteract any leakage pressure, because in-state generators will be rewarded with valuable allowances when they operate, while generators outside Virginia will not be so rewarded. In addition, vertically integrated utilities can self-schedule their generators to run knowing that they will receive allowances at no cost under the program, offsetting any compliance cost the generators might otherwise incur. For all of these reasons, leakage is not expected to present a problem. DEQ expects to monitor this issue as RGGI has done and will address the issue should it be necessary in a future program review. The cap will be 28 million tons (see comment 37), and the allowances will be provided at no cost.

172. Wild Virginia	Article 1 states that the trading program is "designed to reduce anthropogenic emissions of CO_2." However, if the rule applies only to fossil fuels and not other carbon emitting generation, it cannot achieve its goal. According to EPA, total CO_2 emissions from the burning of woody biomass in the electric power sector was 22,900,000 tons in 2016. The proposal applies only to fossil fuels, not biomass or municipal waste. This would allow Virginia's wood burners to continue polluting without regulation and reward coal-fired power plants that switch to burning wood from forests. Burning wood to produce electricity increases CO_2 and particulate emissions compared with fossil fuels. Besides undermining efforts to expand clean energy sources, burning forests for energy destroys forest ecosystems which are a defense against climate change. The regulation could encourage more biomass generators to be implemented. Westrock operates the world's largest solid bleached sulfate board paper mill in Covington. It is powered by a biomass boiler and a 75 MW steam turbine generator. In 2016, this facility emitted 2,020,927 tons of CO_2. NOVEC's Halifax plant generates 50 MW of energy, sourcing wood and whole trees from a 75-mile radius while claiming that its energy is carbon neutral. The 585 MW Virginia City Hybrid Energy Center co-fires coal with 20% wood. It emitted 3,101,460 tons of CO_2 in 2016. Dominion's 83 MW Pittsylvania station unloads an estimated 3,300 tons of wood daily. Dominion's Altavista plant turns pellets, chips, slash, or whole trees into 51 MW of energy, and in 2015 released 393,183 tons of CO_2. Dominion received regional renewable energy and federal incentives by converting 3 coal-fired plants to burn wood. In 2016, Dominion's conversion from coal to wood in Hopewell and Southampton has more than doubled carbon emissions from those facilities. In 2016, these facilities together emitted 885,063 tons of CO_2. Wood-burning power plants pump about 50% more carbon pollution per megawatt-hour into the atmosphere than coal plants. Combined, Virginia’s wood-pellet manufacturing and wood-burning power plants send more than 5 million tons of CO_2 mostly from forest wood into the atmosphere each year. Power plant carbon pollution warms the climate just as effectively whether it comes from burning trees or fossil fuels, which highlights the critical fallacy of treating biomass power plants as "carbon-neutral." Virginia's plan isn’t unique in ignoring emissions from wood-burning plants. The problem also exists with California's cap-and-trade plan, RGGI, and the E.U. trading program. Much of the emissions reductions claimed by the E.U. come from converting coal plants to burn wood pellets imported from the U.S. and Canada,	See the response to comment 67 for further discussion of biomass.

	then assuming the emissions will be offset by future tree growth. As a result, millions of tons of trees are harvested, pelletized and shipped overseas as fuel. The pellet industry is responsible for logging tens of thousands of forest acres each year. Burning municipal waste is also a large emitter of carbon. For example, the Hampton/NASA Steam Plant released 24,653 tons of carbon in 2016. We request that the regulation include carbon accounting for all large scale industrial emitters of atmospheric carbon, including biomass and solid waste burning energy producing facilities.	
173. World Wildlife Fund on behalf of Eastern Mennonite University Creation Care Council, Emory and Henry College, Hollins University, Lynchburg College, Randolph College, Washington and Lee University	As academic institutions, we understand the importance of reducing carbon pollution and the opportunities provided by clean energy. Colleges and universities are committing to reduce their carbon footprint and increase the use of clean energy, because it is the right thing to do and because it makes business sense. Eleven Virginia colleges and universities have committed to becoming fully carbon neutral no later than 2050. Clean energy allows us to save money, hedge against volatile fossil fuel prices, and lock in predictable energy prices. Market-based carbon-reduction initiatives have been highly effective in reducing electric-sector GHG emissions while fostering economic growth and spurring innovation in clean energy technology. We recognize the importance of strong, stable policies that aim to account for the cost of carbon emissions and provide market certainty, allowing colleges and universities to plan and invest for the future. In Virginia, the proposed carbon reduction program would incentivize investments in renewable energy and energy efficiency--creating good-paying jobs for our graduates and others across the state, attracting world-class students, faculty, and staff to our institutions, improving the well-being of our communities, and making Virginia an even more attractive place to live and work. The regulation will be beneficial for Virginia's economy as a whole. This smart initiative will grow Virginia's nascent clean energy industry, help the state stay competitive, reduce energy costs, and improve the resiliency of our electrical grid. It will help utilities transition to a cleaner electric grid while offering more options for higher education institutions, businesses, and residents to access cost-competitive renewable energy. Our institutions value an affordable, reliable, and clean electricity supply, and we commend the Northam Administration for its commitment to lead Virginia in the transition to a low-carbon economy. We appreciate the many months of compiled research and feedback the previous administration gathered from energy stakeholders to develop forward-thinking carbon reduction measures. Steady carbon reduction policies	Support for the proposal is appreciated. DEQ agrees that the program will benefit the state's economy while reducing carbon pollution and its negative impacts on health and welfare.

	will signal that Virginia is committed to embracing clean energy innovation, allowing institutions like ours to thrive for years to come.	

Comments received during the second public comment period (February 4 through March 6, 2019); references to comments and responses relevant to the initial proposal are identified as "initial comment" and "initial response," comments and responses relevant to the re-proposal are identified as "current comment" and "current response":

Commenter	Comment	Agency response
1. About 246 individual commenters	General support for the proposal was expressed.	Support for the proposal is appreciated.
2. About 116 sponsored comments	Thank you for moving Virginia forward to become the first southern state to cap carbon pollution from power plants. This is an important step in tackling climate change. As people of faith, we know that being good stewards means more than praying for resilience, it means standing up for our planet. Throughout the process to link with RGGI, this carbon rule has demonstrated a shift for the better. The lower cap not only shows Virginia takes environmental issues seriously, but will also help heal our Earth to ensure that our children and families have a healthy place to live. All individuals are integral to a just transition to a clean energy future. This cap will give us an advantage to adapt to all possibilities climate change may bring by including communities most impacted by environmental injustices. We give thanks for our governor’s commitment to climate action and look forward to a policy that works toward the benefit of us all.	Support for the proposal is appreciated.
3. About 246 sponsored emails and 846 petition signatories	I support the Clean Energy Virginia Initiative, a proposed regulation that would establish a program to reduce harmful carbon emissions from Virginia power plants and fight climate change. This program would allow Virginia to trade carbon allowances with 9 other states in RGGI to reduce the amount of emissions coming from power plants. This is the ambitious effort we need to combat climate change and will result in the reduction of an additional 5 million tons of carbon between 2020-2030 compared to initial proposals. I urge the board to	Support for the proposal is appreciated.

	adopt this regulation for the good of our climate, economy and public health in Virginia.	
4. About 1225 petition signatories	The final standard should: 1. Retain the base year emission cap of 28 million tons. 2. Fully cover carbon pollution from biomass facilities, which can be more climate polluting than fossil fuel power plants. Virginia's first ever plan to reduce carbon pollution from power plants shouldn't be weakened by special interests. Exempting biomass makes Virginia's carbon program less effective and gives monopoly utilities like Dominion even more of an unfair economic advantage. 3. More fully articulate plans for EJ considerations for program monitoring and evaluation, and require DEQ to include mitigation measures for any adverse program impacts on vulnerable, environmental justice and under served communities that are identified through DEQ's evaluation of the program. 4. More fully articulate DEQ's plan for increasing participation of environmental justice communities in the review of impacts of the program on those communities. This plan should be consistent with the National Environmental Justice Advisory Council's Model Guidelines for Public Participation.	Support for the proposal is appreciated. The commenters' specific concerns are discussed in further detail below.
5. About 336 sponsored emails	Thank you for moving Virginia forward to become the first southern state to cap carbon pollution from power plants. This is an important step in tackling climate change in the state. Throughout the process to link with RGGI, this carbon rule has only gotten better. The reduced pollution cap will make sure Virginia is on track to address with urgency one of the most pressing problems of our time. Lowering the carbon limit will have additional benefits for the health of our children and families. I also appreciate the increased effort to recognize and work with communities most impacted by environmental injustices. These affected individuals are integral to Virginia's just transition to a clean energy future and I look forward to DEQ conducting robust	Support for the proposal is appreciated.

	conversations with leaders from our most vulnerable neighborhoods. I thank you for your commitment to climate action and look forward to the finalization of these important regulations.	
6. About 474 sponsored emails	I am thrilled to see Virginia making history as the first southern state to link with RGGI, and am writing today to ask that you ensure the final standard to cut Virginia's carbon emissions from power plants is as strong as possible. We are already seeing the results of a warming world in our everyday lives: The sea levels along our coast are rising, our risk of heat-related illnesses is increasing, and the lengthening allergy season is boosting rates of asthma attacks. We have no time to wait. We need to lead the South, and we need to act as soon as possible.	Support for the proposal is appreciated.
7. About 902 petition signatories	As a Virginia resident, I'm writing in support of a strong statewide carbon standard. I support your proposal to put a 28 million ton limit on Virginia's carbon pollution next year and your plan to subsequently reduce the amount of harmful pollution emitted by 3% annually. A strong carbon standard will grow our clean energy economy, make our air cleaner, save Virginians money on electric bills, and hold big polluters accountable through a cap-and-invest model. I oppose any loopholes that let polluters burn trees for electricity. Virginians are ready for strong climate action, and we, along with future generations, are counting on you to do the right thing for both the climate and our forests.	Support for the proposal is appreciated. The commenter's specific concerns about biomass are discussed in further detail below.
8. About 165 individual commenters	General opposition to the proposal was expressed.	The commenters' concerns are recognized.
9. 98 petition signatories	On behalf of the Pulp and Paper Resources Council, a grassroots labor organization led by hourly employees advocating for the U.S. forest products industry that supports policies that encourage economic growth, abundant and sustainable fiber supply, and sensible science-based environmental policies, we are writing to oppose the re-proposed regulation. We request that the	The commenters' concerns are recognized. The applicability of non-fossil fuels such as biomass is discussed in greater detail under current comments 24 and 40.

	regulation be revised to make it clear that it only regulated GHG from fossil fuel combustion, and that new and existing industrial facilities are clearly exempt from any allowance obligations. The U.S. forest products industry is vitally important to our nation's economy, employing about 950,000 people. We rank among the top 10 manufacturers in 45 states, and represent 4% of the total U.S. manufacturing gross domestic product. The WestRock Paper Mill is a significant economic driver for our communities, providing over 500 jobs and supporting over $100M in local investment. If care is not taken, the regulation could have a serious and negative impact on the mill. One of our chief concerns is the treatment of energy from biomass, which is crucial to the mill's operation. We encourage DEQ to include a clear and specific exemption for CO2 from non-fossil fuel sources such as biomass. The regulation should also be amended to allow new industrial facilities to qualify for an exemption, as well as existing facilities, to allow for continued growth.	
10. 2 individual commenters	Entering RGGI would require the state's utilities to pay a carbon tax on their fossil fuel power plants and to reduce operation of those plants. This cost would be passed on to consumers and could cost ratepayers of Dominion Energy Virginia $3.3-5.9 billion over the first decade, according to an SCC staff estimate. This is just a backdoor tax and does nothing to solve any problem related to climate change, sea level rise or clean air. I oppose this cap and trade bill that will benefit those selling the credits by picking our pockets and would hurt those who are already struggling on fixed incomes and the poor.	The definition of "tax" is well established in state and federal law. The purpose of the regulation is to control and abate carbon air pollution, not to generate revenue. Rather than impose a tax, the regulation requires the issuance of allowances by the department to CO_2 budget units, which are then traded within the confines of a consignment auction. No money is generated for or sent to the state. Costs to consumers will be minimal, if not lowered; see the initial response to initial comment 61. DEQ reviewed the SCC analysis, and finds a number of issues with its assumptions, as discussed in the current response to current comment 20.
11. 3Degrees	3Degrees strongly recommends that DEQ include a voluntary renewable energy market set-aside in order to foster private demand for renewable energy in Virginia. Private demand for	DEQ recognizes the value of the voluntary renewable energy market as an important tool in reducing carbon pollution but has decided not to implement a separate voluntary

	renewable energy is evidenced by the success of renewable energy programs offered by both IOUs, the introduction of new renewable energy purchase options such as community solar, and the growing demand from corporate purchasing of renewable energy in the form of Green Tariffs that directly support renewable energy generation. These purchasing options are often pursued by customers who are motivated to address climate change by supporting local renewable energy development and accelerating grid decarbonization. The proposal does not provide any avenues for voluntary market customers to ensure that their renewable energy purchase contributes to emissions reductions beyond regulation. As such, a customer purchasing renewable energy generation from Virginia once the program is in place will no longer be able to credibly claim that this renewable energy leads to an avoided emissions benefit on the grid beyond what is required by the program. In order to ensure that the renewable energy contributes to emissions reductions beyond regulation, carbon allowances must be paired with the renewable energy in an amount equal to the avoided CO_2 emissions associated with the generation of the renewable energy. The Voluntary Renewable Energy Market Set-aside allows allowances to be paired with voluntary market renewable energy at no added cost to the voluntary market. In order to support private investments in renewable energy, 7 of the existing RGGI states and California have all implemented a renewable energy set-aside. RGGI provides language for a renewable energy set-aside mechanism in § XX-5.3(l) of the RGGI Model Rule. This mechanism sets aside roughly 2% of the total allowances in a state in any given year and makes them available for free to be paired with voluntary renewable energy purchases in the state.	renewable energy set-aside. The structure of the general 5% set-aside will be under the purview of DMME, which is the appropriate state agency to implement renewable energy and energy efficiency programs. DMME may, at the appropriate time and in accordance with its regulations and policies, seek to implement a voluntary renewable energy market set-aside or its equivalent. However DMME structures the set-aside, it is important to bear in mind that energy efficiency will be an important tool in the control of carbon pollution. Energy efficiency programs reduce in-state demand, which results in the reduction of carbon pollution and the control of potential leakage. DEQ expects that opportunities for voluntary renewable energy projects will be encouraged as a result of this initiative. Although the RGGI model rule does offer offsets, only a single offset project has been implemented in the RGGI region thus far. Given the uncertainty of any benefits associated with a complex offset program, DEQ is not, at this time, proposing to implement offsets; see current response to current comment 25.

	Many local projects risk losing voluntary market support if the renewable energy set-aside is not included in the program. 3Degrees has worked closely with a number of small-scale and residential solar and wind projects in Virginia, supporting the projects by facilitating the sale of the premium RECs from these projects for use by voluntary customers. Through these transactions and other sales, 3Degrees has purchased and facilitated voluntary customer purchases of RECs representing over 340,000 MWh of Virginia-sited renewable energy since 2009. From our experience, the voluntary market is generally providing funding for projects that would not receive funding from compliance REC markets, and often providing more funding per MWh. In some cases the projects would be not financially viable without this revenue stream. If the voluntary renewable energy set-aside is not included in the program, there would no longer be an opportunity for 3Degrees to support projects of this kind in Virginia. 3Degrees urges DEQ to continue to encourage private capital investing in renewable energy in Virginia by implementing the set-aside mechanism. The renewable energy set-aside will lead to continued voluntary demand in Virginia for instate and RGGI-located generation and allow the generation to continue to be eligible for Green-e Energy certification. In addition to the avoided emissions benefit being critically important in the private investment decisions of many voluntary purchasers, it is also a requirement of Green-e Energy certification. Green-e Energy certifies tens of millions of MWh of renewable energy every year, including renewable energy generated in Virginia, and, as the only certification for the voluntary renewable energy market in the U.S., is the de facto	

	standard for private purchasing of renewable energy. Where states have introduced cap-and-trade regulation without a renewable energy set-aside, Green-e has required that Green-e Energy certified renewable energy be matched with purchased allowances equal to the generation's emissions reduction benefit on the grid. This adds a significant cost to renewable energy, such that they generally exit the Green-e/voluntary market. Where private purchasing of allowances is not possible, as is the case in RGGI states, there are no avenues to reclaim the avoided emissions benefit. 3Degrees encourages DEQ to include § XX-10 of the RGGI Model Rule in Virginia regulation. This will allow the issuance CO_2 emissions offset projects from Virginia-sited projects. High-quality carbon offsets can be an important tool for a successful and economic cap-and-trade program. Carbon offsets will be an important tool for achieving emissions reductions cost effectively while encouraging and stimulating innovative climate solutions within Virginia. CO_2 emissions offset projects can address emissions reductions in uncapped sectors and provide other co-benefits to the state.	
12. Alliance for Industrial Efficiency	We commend DEQ for recognizing the most economically efficient means for reducing CO_2 emissions in the regulation: incenting energy efficiency. We also commend DEQ for exempting certain industrial CHP and WHP units, which rightly recognizes the emissions benefits offered by these systems. The Alliance offers recommendations that further recognize the multiple economic, energy efficiency, and GHG reduction benefits that CHP and WHP systems provide: 1. eliminate ownership language in the applicability guidelines; 2. define "primary use" and add system efficiency requirements to the applicability guidelines; 3. add "or facilities" to account for district energy systems in the applicability guidelines; 4. add a	Support for the proposal is appreciated. 1. No further change is needed to account for district energy systems. These facilities must be "located or adjacent to" whether a single facility or multiple facilities. 2. This change is not needed because they are already exempt. It doesn't matter what particular type of power is involved--as long as they meet the requirements of this provision, an industrial facility is exempt. 3. As discussed in the current response to current comment 11 and elsewhere, DMME will determine how the set-aside is allocated.

	thermal energy use exemption; 5. explicitly state CHP and WHP projects are eligible for set aside funds. We greatly appreciate DEQ accepting our recommendations for both eliminating ownership language in the applicability guidelines, and defining "primary use" in the applicability guidelines, as they provide important clarity for potential CHP hosts. Furthermore, we urge DEQ to consider 3 other recommendations which will further encourage greater use of emissions-reducing CHP and WHP systems in Virginia in a way that is consistent with the goal in Virginia's 2018 Energy Plan to deploy 750 MW of CHP by 2030: 1. Add "or facilities" to account for district energy systems in the applicability guidelines. District energy systems capture and reuse waste heat, distributing it through underground piping to provide energy services to neighboring buildings. As written, we are concerned that the proposed rules limit the exemption to CHP that produces heat and electricity for a single building. Instead, we recommend clarifying that the exemption is open to multiple facilities serviced by a CHP system. 2. Add a thermal energy use exemption to the regulation. The hallmark of a CHP system is that it produces both heat and electricity from a single fuel source. Without providing a thermal exemption, the proposed regulation undervalues the full energy output of these systems and the emissions reduction they deliver. 3. Explicitly state CHP and WHP projects are eligible for set aside funds. We commend DEQ for including a set aside for air pollution abatement, such as energy efficiency programs, and we encourage DEQ to add language to the proposed regulation clarifying that such projects are eligible for set aside funds. This	

	will help ensure that potential project hosts are aware of the opportunity. Explicitly clarifying in the regulation that set-aside funds are available for CHP and WHP projects (which are already included under the definition of "energy efficiency programs") would eliminate confusion surrounding eligible projects and would encourage additional CHP and WHP deployment.	
13. American Council for an Energy-Efficient Economy (ACEEE)	Energy efficiency is an important strategy to reduce emissions in the electric power sector. As it lowers electricity use, energy efficiency avoids emissions of CO_2 and other harmful pollutants, often at lowest cost. ACEEE estimates that by implementing energy efficiency programs and policies, Virginia could exceed the emissions reductions required through the proposal in 2030. In an allowance trading program, CO_2 reductions from energy efficiency will help sources meet the state's CO_2 emissions limit by reducing electricity production. These reductions in energy consumption can lead to big gains in public health. Reducing annual electricity use by 15% nationwide would prevent nearly 30,000 asthma episodes each year and save Americans up to $20 billion through avoided health harms annually. Virginia ranked among the top 15 states that would see the largest avoided health harms from investing in energy efficiency and thereby reducing emissions in the electric power sector. While supplying affordable, reliable electricity to residents and businesses, energy efficiency is also a lowest-cost option to reduce CO_2 emissions. Research shows that at a range of about 2-5 cents per kWh and an average of 2.8 cents per kWh, energy efficiency programs cost 2-3 times less than generating power from traditional sources. States that invest in energy efficiency can reduce emissions at a lower cost than is possible through other options. However, this does not mean that	DEQ recognizes the value of energy efficiency as an important tool in reducing carbon pollution; however, the structure of the set-aside and to what programs the allowances will be allocated will be under the purview of DMME, which is the appropriate state agency to implement the set-aside. DMME may, at the appropriate time and in accordance with its regulations and policies, implement an energy efficiency set-aside as described by the commenter. The set-aside will be 5% in the early stages of the program; the set-aside may be revised at a later date as the state gains experience with the program and with the program DMME develops. In particular, the commenter notes the health impacts associated with changes in air quality due to RGGI. Virginia's own analyses of health benefits corroborate the RGGI studies, as discussed in initial response to initial comment 61. Most recently in November 2018, for the purpose of this re-proposal, an analysis using the COBRA model was run in order to determine the health benefits of emission reductions from implementation of this regulation. Again, this analysis showed a significant health benefit, with totals for the years 2025, 2028 and 2030 between $18M - $41M. DEQ agrees that there are advantages to both the consignment and direct auction approaches; at this time, Virginia is relying on a consignment approach in order to ensure that the program will be implemented in compliance with Virginia law.

	energy efficiency deployment will necessarily increase, even when it is more cost-effective than other CO_2 reduction options. Current market and regulatory barriers to investment in energy efficiency can hinder its use as a compliance strategy in a trading program. DEQ should consider several strategies to encourage deployment of energy efficiency to help reduce energy use, energy bills, and energy-related emissions. ACEEE supports the role of energy efficiency in the proposal and recommends that the state further encourage and support the use of energy efficiency in an allowance trading program. DMME will be allocated 5.0% of the base or adjusted budget allowances to be consigned to auction by the holder of a public contract with DMME to assist in the CO_2, by implementing programs that lower base and peak electricity demand and reduce the allowances to be budgeted for energy efficiency programs. ACEEE supports this provision, and recommends that DMME use this set-aside to invest in energy efficiency projects that save energy and reduce utility costs for public and private sectors alike. While investing in energy efficiency can reduce emissions at a lower cost than is possible through other options, there are also significant ancillary benefits, such as improving air quality and human health, and enhancing community resilience. An analysis by Abt Associates assessed the public health impacts associated with changes in air quality due to RGGI implementation from 2009 to 2014. The results estimate the program avoided 300-830 premature deaths, realized $5.7 billion in health savings and other benefits, and avoided more than 8,200 asthma attacks. The analysis highlights the impact of energy efficiency investments contributing to the high emission reductions and health gains in the start of the analysis period and	

	targeting peak demand periods with high emissions. These findings underscore the significant health gains that can be achieved through allowance trading programs to combat climate change that include investments in energy efficiency. Energy efficiency is also an ideal component of any resilience strategy because it aids emergency response and recovery, helps with climate change adaptation and mitigation, and provides social and economic benefits. By reducing energy demand in buildings, improving transportation efficiency, and deploying CHP, communities can experience important resilience benefits that reduce vulnerability and increase capacity to cope with the impacts of climate change. ACEEE recommends the state recognize these multiple benefits by investing auction revenue into energy efficiency programs. Proceeds from a revenue-raising auction can be reinvested in energy efficiency to further reduce emissions, as seen in the states participating in RGGI where energy efficiency accounted for 58% of cumulative investments through 2016. RGGI states have invested more than half of the $3 billion in revenue proceeds over the life of the program to fund a variety of energy efficiency programs. These investments are augmented by complementary policies in RGGI states, including energy efficiency resource standards, building energy codes, state government-led initiatives, transportation and land-use policies, and appliance standards. The emissions reductions and economic benefits of energy efficiency can be amplified by implementing energy efficiency policies alongside an allowance trading program. ACEEE recommends Virginia look to states participating in RGGI as examples of how to increase investment in energy efficiency. Investments from RGGI reach a variety of customer types, including	

	businesses, municipalities, and low-income communities. States invest much of the auction revenue in utility energy efficiency programs, state green banks, and/or programs run by state energy offices offering incentives, technical support, and financing. Further, ACEEE recommends that Virginia utilities align their spending of allowance revenues to complement utility-funded energy efficiency programs set forth over the next decade. Utilities could design energy efficiency programs to deliver new measures and serve new customer segments. In addition, utilities could offer measures that aim to mitigate indoor health and safety risks while saving energy for customers. Investing in addressing health and safety measures can improve the health of residents while increasing participation in weatherization programs. Investing revenues in energy efficiency drives considerable energy savings and emissions reductions, helping to cut emissions beyond what a carbon price alone could achieve. In addition, these energy savings reduce the cost of carbon pricing to households and businesses.	
14. American Electric Power/Appalachian Power Company (AEP/APCO)	Regulation of CO_2 emissions should not be pursued by individual states. EPA is currently evaluating a national policy for reducing CO_2 emissions from fossil fired generating units and has existing regulations to monitor and report CO_2 emissions. A patchwork of individual state regulations in front of this federal plan may hamper the state through placing added hardship on sources within the state should the state's requirements be more stringent than the federal plan. Where future state regulatory actions will differ from other states or the federal to be made that may be less effective in reduction of emissions and costlier than if the compliance plan can be based on a uniform set of rules among the states. This state-specific proposal imposes additional requirements on APCO and will significantly increase compliance	DEQ agrees that climate change should be addressed through a coherent national program. However, in the absence of a coherent national program, the Commonwealth is well within its authority to address air pollution within its borders. Linking to RGGI is not a "go it alone" approach; it will enable Virginia to leverage its pollution reduction efforts with a well-established, proven effective interstate program. Note that the proposed ACE program is for improving efficiencies, and is not an explicit emissions trading program. It is unlikely that it will conflict with existing emissions trading programs. Indeed, participating in RGGI may give Virginia facilities an advantage in meeting GHG controls from other GHG reduction programs sooner than had they not participated. RGGI gives sources flexibility in compliance, and participation in ACE can only help them comply with RGGI.

	costs to our operation without yielding any additional reduction in CO_2. Those additional costs will be borne by the industrial, commercial and residential customers within the state. Additional costs to businesses under the proposal will put Virginia at a relative disadvantage to other states for business development with no environmental benefit. The total emissions from the state are estimated to be about 1% of the nation's total emissions and less than 0.01% of the world's annual emissions (based on 2015 data from EIA and IEA). Reductions of CO_2 by local sources will not change the local ambient concentrations since this gas is a well mixed parameter of the atmosphere. In reality, a total elimination of CO_2 emissions from all sources in Virginia will have no significant effect on the global concentration. Of particular concern is the lower emission cap of 28 million tons. The proposed reduction of the emission cap will increase the stringency of the program, thereby increasing the cost of compliance, which will be borne by Virginia ratepayers. The board has not provided adequate information to support the establishment of a lower emission cap. As evidenced by Virginia's small contribution to global GHG emissions, the proposed reduced cap appears to be both arbitrary and capricious. The current control technology for capturing CO_2 remains in the developmental stage. Other administrative items of note include the need to maintain a new database for GHG emission reporting, operating and maintaining a new database and software program for allowance trading, and maintaining records associated with CO_2 emissions and accompanying reports for 10 years. The CO_2 emission reporting is required on a quarterly basis. The records for CO_2 emissions are already reported in two other programs. The	The new 28 million ton cap is a more realistic reflection of emissions, and will result in a more realistic emissions reduction path. Yet this more stringent cap has been demonstrated to not create significant additional costs to generators or consumers; see, for example, initial comment 61. It is unclear how maintaining records for this emissions trading program will be significantly different from any other emissions trading program implemented in Virginia. Because Virginia is linking to an existing trading program, it is not anticipated that any new Virginia-specific database will be needed. The Commonwealth is expected to use the RGGI COATS system to track allowances and emissions. The COATS system obtains CO2 emissions data from the EPA CAMD data system and therefore no redundant emissions reporting will be needed to support the RGGI process. DEQ does not expect any additional data recording or tracking requirements of the program to be overly burdensome to the regulated sources.

	CO_2 is reported into CAMD quarterly as the diluent for measurement of other parameters for Title IV and CSAPR and is reported annually along with other GHG parameters separately as required by the GHG rule (40 CFR Part 98). The federal program for GHG emission reporting requires a certified inventory to be submitted annually for each source at the facility. CO_2 is also used as a diluent for other Title IV related reporting and is reported into CAMD quarterly. This proposal will require additional reporting into a separate database operated by RGGI. The database operated by RGGI and the allowance tracking system is outside the current system utilized for Title IV and CSAPR databases. The facilities will have to maintain a separate account for the allowances and track progress in separate systems. The proposed rule does not detail the cap and trade program mechanics to allow adequate review and comment on the impacts and associated costs of this program to either the affected sources or the customers within Virginia. All other programs require records to be maintained for 2 years for Title IV and 5 years for Title V and CSAPR. Additional storage capacity for maintaining emission records are needed to satisfy this proposal. In summary, the current proposal will result in significant additional costs to the Virginia ratepayers but will not lower GHG and could result in premature retirement of Virginia generating units. The rule would discourage development of new fossil generation in Virginia, forgoing potential employment, economic and tax base benefits associated with such projects. The development and availability of CO_2 controls are in the early stages of development and are not proven on any industrial scale operations. As such, compliance with the proposed regulation will require curtailment of fossil-fired generation within Virginia, requiring other sources to be used, at a higher cost and	

	possibly outside Virginia's borders. Therefore, AEP recommends that the board not move forward on this proposal.	
15. Calpine	As expressed in our April 2018 comments, Calpine continues to strongly support Virginia's carbon cap-and trade regulation. We continue to support the implementation of a program in Virginia that places a clear price on carbon emissions and that allows for trading with the RGGI market. Calpine supports cap-and-trade programs that place a clear price on carbon emissions from both new and existing power generators in a way that allows such a price to be reflected in wholesale power prices and that are designed and administered in a way that minimizes market distortions. Virginia's program can be finalized to achieve that objective, but it is important for DEQ to finalize an allowance budget at a level that will result in meaningful carbon reductions by incentivizing environmentally-efficient dispatch of power generation facilities. For these reasons, we support the re-proposed regulation including the proposed emissions budget of 28 million tons in 2020. Recognizing the historically low allowance prices in the RGGI region and the fact that Virginia's linkage with RGGI will significantly expand the size of the RGGI market, the budget must be based on reasonable assumptions about the expected generation mix in Virginia given market dynamics. We support the need for the reduced emissions budget based on the revised projections related to electricity demand, lower natural gas prices, and the projected generation from renewable resources. Overall, Calpine supports additional states participating in the RGGI program to support a broader, more flexible emissions market, helping to improve market competitiveness and trading efficiency while helping to lower carbon abatement costs.	Support for the proposal is appreciated, particularly support for the emissions cap.
16. Center for Resource	The RGGI Model Rule includes an optional VRE set-aside provision,	As discussed in the response to comment 11, DEQ recognizes the value of the

Solutions	which a state regulatory agency may use to allocate a certain number of tons from the CO_2 budget to a VRE set-aside account for each control period based on voluntary purchases of renewable energy generation located within RGGI. Under an emissions cap, renewable energy generation reduces emissions but does not affect the cap. As a result, the emissions reductions from renewable energy generation driven by voluntary and corporate purchases can be reversed if those actions are not considered in the design of the cap-and-trade program. In other words, VRE can simply create space under the cap for more emissions. Without a VRE set-aside, there can be no verifiable avoided grid emissions associated with renewable energy purchases, and voluntary action may just reduce compliance obligations for regulated entities. For this reason, voluntary sales of renewable energy generated within RGGI to customers in a RGGI state without a VRE set-aside are not eligible for Green-e certification. If Virginia does not adopt a VRE set-aside, then Virginia customers may be restricted from buying certified renewable energy from facilities located within RGGI, and renewable energy providers in Virginia may see reduced in-state demand in the voluntary market. Furthermore, VRE purchasers often consider geographic location when evaluating renewable energy purchasing options; forcing them to choose between their proximity to the renewable energy they purchase and the avoided emissions value of this generation presents an unnecessary obstacle to impactful procurement. A cap on emissions from the power sector not only affects the claims associated with the emissions benefits of VRE but also impacts voluntary demand for and investment in renewable energy. Companies and individuals that purchase and invest in renewable energy voluntarily often do	voluntary renewable energy market as an important tool in reducing carbon pollution but has decided not to implement a separate voluntary renewable energy set-aside. The structure of the 5% set-aside will be under the purview of DMME.

	so in order to take steps beyond the actions attributable to state or federal policy. In this way, their investment has an incremental impact, particularly with respect to GHG emissions. This difference is referred to as "regulatory surplus." However, where renewable energy sold into the voluntary market does not have this effect, and instead only serves to help regulated entities comply with existing regulatory requirements, this production cannot be considered surplus, therefore undermining demand for VRE. Where voluntary demand for renewable energy is limited, by extension, so is the overall development of renewable energy and the associated emissions reductions. Regulatory surplus is critical to sustaining clear voluntary claims and has been helpful in sustaining voluntary investment in renewable energy beyond what is already required by regulation in the RGGI region. Because a set-aside mechanism preserves regulatory surplus for VRE, it can help leverage private capital to drive renewable energy generation in excess of state mandates. In the last 5 years, there have been approximately 3.8 million MWh of Green-e certified sales to retail customers in Virginia. In 2017, this included nearly 700,000 MWh sold to about 35,000 individual customers. This shows considerable voluntary demand for renewable energy in the state. If Virginia does not include a VRE set-aside, it is unlikely that renewable energy from any RGGI state could be sold in a Green-e certified product to customers in Virginia. Adoption of a VRE set-aside would allow this demand to continue to be met by resources in Virginia, allowing the state to capture private investment dollars that could otherwise go elsewhere. In other words, the implementation of a VRE set-aside would remove a significant	

	barrier to investment in and development of renewable energy in Virginia beyond that which is mandated by RPS regulations, and this could lead to increased revenue resulting from growing voluntary and corporate participation in renewable energy markets.	
17. Ceres on behalf of Adobe, eBay Inc., Gap Inc., IKEA USA, JLL, LinkedIn, Mars Inc., Microsoft, Nestlé USA, Outdoor Industry Association, Salesforce.com Inc., Starbucks Corporation, Unilever, and Worthen Industries	On behalf of several large businesses with operations and employees throughout Virginia and across the U.S., we write to express our strong support for the re-proposed regulation. Companies across Virginia are setting goals to reduce their GHG emissions and increase their use of clean energy because they know it is the right thing to do for both the environment and their bottom lines. More than 43 major Virginia companies have set goals to power their operations with 100% renewable energy, and many more have set other goals to scale up renewables, improve the energy efficiency of their facilities, and reduce their carbon footprint. Market-based programs such as RGGI have proven successful in decarbonizing the electricity grid while scaling up clean energy resources and providing enormous net benefits to the economy. Virginia's participation in RGGI is supported by many companies with major operations in the state, and will allow Virginians to reap the benefits of cleaner air, a more resilient electricity grid, reduced exposure to high electric fuel prices, and more local clean energy jobs. It would also make Virginia more attractive to innovative, forward-thinking companies and their products and services. We appreciate the stronger baseline of 28 million tons of CO_2, as it will be more in line with the state's actual 2020 emissions. We also encourage Virginia to include power facilities that co-fire with woody biomass under the emissions cap, as such facilities can be a significant source of carbon pollution that would otherwise go unaccounted for. We encourage adoption of the many renewable energy and energy	Support for the proposal is appreciated, especially from CERES members with significant operations in Virginia. DEQ agrees that energy efficiency is an important tool in the control of carbon pollution. See the current responses to current comments 24 and 40 for further discussion of biomass.

	efficiency technologies that will help keep electricity costs down. Renewable energy technologies are increasingly more cost-effective than fossil fuel sources. Meanwhile, energy efficiency consistently remains one of our least expensive resource options. As has been proven in RGGI states, concurrent investment in energy efficiency can reduce electricity prices even further.	
18. Dominion	Virginia linking to the RGGI program does not reduce emissions regionally. DEQ's modeling results indicate that Virginia entering the RGGI program in 2020 with a statewide emissions cap at the reduced levels proposed and imposing RGGI's approximate 3% per year cap reduction to achieve a 30% emission reduction over 2020-2030 does not result in overall carbon emission reductions in the Eastern Interconnect (EI) or PJM regions by 2030. The analysis shows, when comparing emissions in the reference case where Virginia is not linked to RGGI with emissions in the policy case where Virginia is linked to RGGI, that emissions reductions achieved in Virginia and the RGGI program are largely offset by emissions increases in the non-RGGI portions of the EI and PJM regions. Cumulatively, over 2021-2030, emissions in the portion of the PJM region subject to RGGI are reduced by about 45 million tons, but increase by the same amount in the non-RGGI portion of PJM. In the EI region, as a whole, cumulative emissions over the 10-year period are only reduced by 3 million tons, with about a 57-million tons reduction in the RGGI portion of the EI offset by a 54-million ton increase in the remainder of the EI outside of the RGGI program. Since modeling information provided for incremental generation was confined to the RGGI states and not provided for states outside of the RGGI region, it is difficult to determine whether the minimal carbon emission reductions modeled for the entire EI region were the result of the RGGI program or the result of "natural" retirement of older	DEQ's modeling results demonstrate the proposal will be effective at reducing CO_2 emissions from Virginia's electricity sector. While the Commonwealth cannot control the actions of other states in the region, a number of other governors have taken or appear poised to take steps to reduce emissions from the power sector in the region. It is also likely that the federal government will move to reduce emissions from the electricity sector during the time horizon contemplated by the proposal. Thus, it is difficult to predict what emissions trends will be outside of Virginia and outside of the RGGI states. DEQ notes that the proposal will allocate emissions allowances on an updating, output basis. This means that the more electricity generated by a covered unit, the more allowances it will receive under the program. The program thus rewards the generation of electricity within Virginia, while generators outside Virginia will have no such incentive. Reputable independent analyses have tended to show that updating, output-based allocation is an effective method of deterring the shifting of generation from an area with an emissions cap to an area without such a cap. The analysis completed for DEQ by ICF does not factor in this allocation approach and therefore it likely overstates the extent to which generation will shift to areas outside of Virginia. Regardless of how the commenter chooses to characterize emissions reductions achieved by RGGI, reductions will be achieved both within the RGGI program and within Virginia borders due to the downward moving cap. These reductions are essential at the

	coal plants in the region. DEQ's modeling did not include New Jersey joining RGGI in its policy case. New Jersey plans to rejoin RGGI and, like Virginia, New Jersey has proposed a regulation to begin implementing the RGGI model rule beginning in 2020. Their modeling, which includes both New Jersey and Virginia in RGGI, shows generally similar results with emission reductions achieved in the RGGI states mostly offset by emissions increases outside of the region. The modeling showed only about a 0.6% reduction in emissions across the entire PJM region comparing the policy case to the reference case.	cooperative state level in the absence of any federal leadership. Virginia faces some of the most severe impacts in the country related to climate change, and leadership in this area is essential.
19. Dominion	If Virginia joins RGGI, the projected increase in emissions in states outside of the RGGI program suggests emissions leakage will occur as a result of increased energy imports from more carbon-intensive energy sources in states that are not part of the RGGI program. This is borne out by modeling results that show significant increases in power imports into Virginia. With Virginia linked to RGGI, net energy imports into Virginia by 2030 increase by about 28% with approximately 8.2% of total net generation from imported power under the case with no carbon regulations in Virginia to about 10.5% of total net generation from imported power for the case with Virginia linked to RGGI. DEQ's latest proposal includes an updating output-based allowance allocation approach that it believes will incentivize utilization of NGCC resources as a means to counter leakage. Under this approach, allowances are allocated annually to affected generating units based on generation output (MWh of operation) averaged over the previous 3-year period. However, while an updating output-based allocation approach may be more favorable to NGCC units since they emit much less carbon per unit of output, it does not address	The increase of energy imports to Virginia projected in the IPM modeling results is overstated. The difference between 8.2% of total net generation to about 10.5% is actually a 2.3% difference, not a 28% increase. Even this 2% increase in imports may be overstated because the IPM modeling conservatively did not take into account the proposed updating output-based allocation method. Under this updating output-based allocation, the more electricity generated by a covered unit, the more allowances it will receive under the program. The program thus rewards the generation of electricity within Virginia, while generators outside Virginia will have no such incentive. Contrary to the comment's assessment, reputable independent analyses have tended to show that updating, output-based allocation is an effective method of deterring the shifting of generation from an area with an emissions cap to an area without such a cap. For example, independent research conducted by the Regional Economic Studies Institute and Resources for the Future and released in August 2017, concluded that updating, output-based allocation can be an effective tool to counter incentives to shift generation to areas not covered by an emissions cap. (See "Using Production Incentives to Avoid Emissions Leakage," 2017 (Dallas Burtraw, Karen Palmer, Anthony Paul and Hang Yin), *Energy Economics,* 68: 45-56 and

	leakage. Natural gas-fired units in Virginia will still be subject to a CO_2 cost adder that units outside of the carbon constrained program will not be subject to. Thus, the effect of RGGI-equivalent reduction requirements in Virginia is likely to limit the dispatch of highly efficient and lower emitting NGCC facilities in Virginia and encourage the dispatch of higher emitting resources and increased emissions in neighboring states outside of the RGGI region. This will increase the carbon intensity of the electricity used by Virginia customers. Virginia's carbon footprint from electric power generation is already significantly cleaner than many of its neighboring states and PJM as a whole. With the federal CPP currently stayed and proposed to be replaced with the ACE rule, few states outside of the RGGI program and along the west coast have or are proceeding with definitive carbon regulations. This includes all of the remaining states that are part of PJM (except Maryland and Delaware which are part of RGGI). In the PJM Interconnect, units are dispatched based on replacement cost of the variable components required to run the unit. This is known as economic dispatch. The variable components include fuel and emission allowances, such as RGGI allowances. The replacement cost changes are based on the market value of the type of fuel used in a unit and the market value of the emission allowance. Dominion does not choose when to operate its units, but instead, units are called upon by PJM. If Dominion units are above the target price for the day, other units, generally less controlled and more carbon intensive, will be called upon and operated to meet the PJM load demand due to their ability to operate at a lower cost. PJM does not take environmental impact into account when dispatching units. When Virginia units bid into the electric market, their bids will incorporate a RGGI-based	https://www.rff.org/publications/testimony-and-public-comments/comments-for-virginia-on-the-co2-budget-trading-program/. The commenter correctly notes that the value of the emissions allowances are one factor in bids into the PJM wholesale market. The commenter neglects to consider that under the proposal regulated units will receive allowances from the state at no cost. To the extent a free allowance adds no cost because it is acquired at no cost, there is no added variable cost to add to unit's bids into the PJM wholesale market. Similarly, to the extent updating, output-based allocation results in more free allowances simply by generating more means the allowance allocation functions as a subsidy for VA units earning the extra allowances. Importantly, the IPM modeling did not analyze the effect of allowance allocation and should be viewed as a very conservative take on potential shifts in electricity production. Numerous monitoring, review and compliance checks are already built into the RGGI program as well as in Virginia law. See the initial response to initial comment 91 and the current response to current comment 31 for a discussion of leakage. The updating output-based allocation is expected to encourage generation in the state, rather than discourage it. Note that carbon intensity in the region is declining, not increasing; see, for example, current comments 31 and 46.

	carbon cost that bids from other PJM resources outside of the RGGI program will not have. As a result, Virginia generators will be economically disadvantaged, and increased imports will be dispatched into Virginia. Coupled with the possible forced retirement and curtailment of fossil fuel-fired resources, this raises reliability concerns with increased dependence on out-of-state, more carbon-intensive power.	
20. Dominion	DEQ's consultant, the Analysis Group, analyzed monthly electricity bills for Virginia residential, commercial and industrial consumers. The results, which were summarized in a presentation posted on DEQ's website, projects that electricity bills will be lower with Virginia participating in RGGI. According to the study, higher firm power prices under the cap-and-trade program are more than offset by projected revenue from the sale of CO_2 emission allowances that are passed (by assumption) on to consumers. The Department of Planning and Budget (DPB) reviewed the study and largely concluded that it lacked the resources to verify the model or its assumptions. The SCC reviewed the DEQ cost impact study and performed its own analysis. SCC estimates the total cost to Dominion customers to be $3.3 billion for Virginia linking to RGGI or $5.9 billion for Virginia joining RGGI over 2020-2030. Based on SCC analysis, typical residential customer bills are estimated to increase by $7-12 per month over the 2019-2043 study period, with an average $6.95 per month with Virginia linking to RGGI . These costs are significantly higher than the minimal impact estimated by DEQ. SCC states that RGGI compliance increases the dispatch cost of fossil generation making it less competitive. This causes such generation to run less or be taken out of service. SCC further explains that the DEQ study modeled Dominion and AEP as deregulated utilities in a competitive market with merchant	The comment refers to an analysis by State Corporation Commission (SCC) staff based on modeling conducted by commenter. DEQ staff reviewed the SCC staff statements and the commenter's modeling analysis. What follows is a brief assessment of this analysis. SCC staff relies on modeling that was conducted in private by Dominion, the state's largest utility and one of the parties to be regulated by the proposed electricity sector cap. The results of any modeling exercise depend on the assumptions used. Many key assumptions used by Dominion in its modeling analysis for SCC staff have not been disclosed, making it hard to assess the reasons for Dominion's modeling results. Among these is the method used by Dominion to capture the energy efficiency investments required under state law, in particular the Grid Transformation and Security Act (GTSA). To the extent Dominion's modeling assumptions were disclosed, they suggest that Dominion and in turn SCC staff significantly overstate the potential costs of the program. Dominion's analysis assumes that Virginia generators will be limited to the number of allowances allocated by the state. This reflects a basic misunderstanding for how a regional cap-and-trade program works. Virginia generators will have access to all of the allowances issued by any of the RGGI states. Dominion's analysis also assumes a price for allowances that significantly exceeds what is expected. The table below shows the allowance

<table>
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<td>power plants. While much of the power generated in the RGGI states is supplied by merchant power, most of the power generation in Virginia is owned and operated by regulated utilities and the cost of compliance is borne by customers. SCC also identified that the Analysis Group applied a low discount rate for the weighted cost of capital projects that may be needed to replace generation from early retirements and therefore understated the cost of future capital investments by Virginia utilities.</td>
<td>prices expected in DEQ's analysis, which matches the analysis of the RGGI states, compared with the prices assumed by Dominion and SCC staff. Dominion assumes prices that are between 50--99% higher.

<table>
<tr><th>Year</th><th>DEQ Analysis</th><th>Dominion Assumption</th><th>Percentage Difference</th></tr>
<tr><td>2021</td><td>$4.01</td><td>$6.00</td><td>50% Higher</td></tr>
<tr><td>2022</td><td>$4.01</td><td>$6.54</td><td>63% Higher</td></tr>
<tr><td>2023</td><td>$4.01</td><td>$6.87</td><td>71% Higher</td></tr>
<tr><td>2024</td><td>$4.55</td><td>$7.35</td><td>62% Higher</td></tr>
<tr><td>2025</td><td>$4.55</td><td>$7.86</td><td>73% Higher</td></tr>
<tr><td>2026</td><td>$4.55</td><td>$8.41</td><td>85% Higher</td></tr>
<tr><td>2027</td><td>$5.18</td><td>$9.00</td><td>74% Higher</td></tr>
<tr><td>2028</td><td>$5.18</td><td>$9.63</td><td>86% Higher</td></tr>
<tr><td>2029</td><td>$5.18</td><td>$10.30</td><td>99% Higher</td></tr>
<tr><td>2030</td><td>$5.65</td><td>$11.02</td><td>95% Higher</td></tr>
</table>

SCC staff acknowledges that Dominion assumed an allowance price higher than the price expected by DEQ, the RGGI states and other independent analysts. SCC staff also acknowledges that this assumption contributes to their conclusion that bill impacts will be higher.

The SCC analysis used the ECR trigger price as the RGGI allowance floor price instead of using the RGGI program's actual floor price, which is significantly lower. This misconstrues the rule's ECR provisions--while intended to boost allowance prices, the ECR will not act as an allowance price floor. The SCC analysis, therefore, projects much higher future RGGI allowance prices, and hence compliance costs, than does DEQ's IPM modeling. DEQ's modeling takes into account the rule's ERC provisions, but nevertheless projects future allowance prices that fall below the ECR trigger, despite the withdrawal of the ECR allowances from the allowance market.

Dominion's analysis for SCC staff assumes that certain coal units will not retire for economic reasons in the absence of a carbon cap. The basis for this assumption is not known and may not be reasonable. To assume that the Chesterfield coal units will continue to operate in the 2034-39 timeframe (70 years after that plant was put into operation) when similar coal units are expected to retire for economic reasons,</td>
</tr>
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		raises questions about the validity of Dominion's analysis for SCC staff. Similarly, the units at Clover are assumed to continue to operate until their 55th birthday. In addition, based on publicly available information from EIA, operation of the Chesterfield units has decreased by approximately 50% over the past 10 years, and operation of the Clover units has decreased 33%. This suggests that these coal units--like coal units everywhere in the U.S.--are under considerable economic strain already because of low natural gas prices and low renewables costs. Dominion under-estimated the share of allowances it would receive under DEQ's proposed allocation rules. Under the proposal, generators are allocated allowances according to their generation. Even though Dominion has access to generation totals in its analysis, it chose to assume a flat rate of allocations. Further, that flat rate was likely an under-estimate: Dominion assumed it would receive 70% of allowances available to regulated entities, despite currently owning and operating facilities responsible for roughly 80% of the electricity to be covered by the program (Source: 2016 and 2017 EIA Data). The SCC rejected Dominion's load forecast in its 2018 IRP analysis. It is not clear how the Dominion modeling used in the SCC analysis forecasted load or whether the load forecast was any different from the one rejected in the IRP context. This is important because an overstated load forecast will yield overstated bill impacts. Many of Dominion's results were not disclosed. SCC only disclosed average costs to ratepayers over a 25-year time period, with no explanation of what impacts are borne when, making it impossible to fully understand or evaluate Dominion's results. SCC staff provide no explanation for the math that leads to their estimates of bill impacts. Without transparency around these calculations, it is not possible to

		fully assess their methodology. To the extent the calculations are disclosed, they appear to double count the cost to Dominion. DEQ's analysis uses the IPM model--the same model used by Dominion and many other utilities to forecast the wholesale electricity market. In DEQ's analysis, both Chesterfield and Clover retire for economic reasons even if Virginia does not implement a cap on carbon emissions. Thus, the chief difference between Dominion's modeling and DEQ's modeling is the timing of the retirements of Chesterfield and Clover. As noted above, Dominion's analysis rests on the unlikely assumption that these aging coal plants will operate well into the 2050s. SCC staff provide no consideration of impacts in Virginia as a whole. Since the analysis was performed by Dominion, it ignores the rest of the state, which has important implications for the analysis, especially given the key role of the Clover facility in the analysis, which is co-owned by Dominion and ODEC. Also see, for example, a discussion of heath benefits in initial response to initial comment 61 and current response to current comment 13.
21. Dominion	Linking to or joining RGGI will impose significant additional cost to Virginia electricity customers while achieving insignificant emission reductions regionally. It will encourage lower cost electricity imports from out-of-state sources that are more carbon-intensive. Reductions in carbon emissions in Virginia and the RGGI region will be offset by emission increases elsewhere within the non-RGGI portion of PJM and the EI. DEQ's modeling also shows that although about a 5% reduction in Virginia CO_2 emissions is achieved cumulatively over 2020-2030, emissions through much of the 10-year period are projected to be above the state-level emission cap. This implies that compliance with the program will require allowance purchases over and above the	See the current response to current comment 20 for a detailed discussion of the SCC analysis. For a response to comment on electricity imports and leakage, see the response to comment 19. The ability to access low-cost allowances from other states lowers the cost of the proposal and allows commenter and other regulated entities in Virginia the flexibility to operate when it is in the best interests of Virginia. As discussed in current comment 71, note that SCC rejected Dominion's 2018 IRP in part due to the failure to include $870 million in proposed energy efficiency investments in the IRP load forecasting. Dominion's IRP analysis appears to suffer from many of the same defects as the analysis Dominion

	amount of allowances DEQ will allocate to Virginia sources. The revenue from the purchases of these additional allowances will flow to other RGGI states while the cost of compliance will be borne by Virginia electricity customers. Dominion has modeled RGGI impacts to Virginia customers in the 2018 IRP proceeding filed May 2018, which shows that the cost increase to Virginia customers is over $1.5 billion net present value which equates to a monthly average rate increase of $4.10. Joining RGGI would increase cost to Virginia customers to over $4 billion net present value which would equate to a monthly average rate increase of $6.83. This modeling was based on the initially proposed 33-34 million ton cap, which has now been reduced by 15% to 28 million tons. Although the analysis did not include specific elements of the GTSA, which was not final at the time modeling assumptions for the 2018 IRP were locked in, it did include over 4.5 GW of new solar and offshore wind--an amount comparable to the renewable build specified in the GTSA.	completed for SCC staff, discussed more fully in the response to comment 20.
22. Dominion	Part of DEQ's explanation for the reduced baseline emissions cap includes the incorporation and assumption of the deployment of additional clean energy programs in other RGGI states. DEQ does not provide a description or any detailed information regarding these programs and the extent of additional emission reductions they may achieve. It therefore is difficult to assess how much of a driver these programs served in the decision to lower the Virginia baseline cap. Nevertheless, it does raise question as to why such programs served as drivers for DEQ to adjust the Virginia baseline cap while no additional adjustments will be made to the emission caps in the other RGGI states within which these very programs will be implemented. To the extent that the future, planned deployment of clean energy programs in other RGGI states are deemed	This comment mischaracterizes the basis for the emissions cap in the proposal. The IPM analysis projects that emissions in Virginia will be 28 million tons of CO_2 in 2020. This projection is based on the best modeling inputs available, including inputs relating to expected energy efficiency and renewables investments in Virginia and elsewhere in the EI. This approach is consistent with best modeling practices. Thus, the 2020 Virginia emissions cap is set at the expected emissions level in 2020. The input file for the latest IPM modeling rule included not only clean energy and efficiency programs expected in Virginia, but also included updates from all the other RGGI states on these programs as well. A significant additional investment in renewable energy generation was captured in these inputs along with further investments in energy efficiency projects. This input file is available and

	influential in establishing Virginia's 2020 baseline budget, it is logical to assume that the planned implementation of the GTSA in Virginia likewise could factor into the future budgets of the other RGGI states. This suggests that any modifications to RGGI state budgets attributed to these various state clean energy programs should be spread across the entire RGGI region and not just Virginia. An additional consideration regarding the proposal to reduce the baseline cap is that RGGI re-assesses its program every 4 years based on historical performance. Since 2009, RGGI has conducted two program reviews, one in 2012 and one in 2016-17. Both of these reviews resulted in a reduction of going-forward CO_2 emission caps for the RGGI region. The 2016-17 program review led to the decision to increase the annual reduction of the regional emission cap beginning in 2021 from the current 2.5% per year rate to 3% per year through 2030. The next assessment period is scheduled to occur in 2021, which is only one year after Virginia would begin its participation. This means that the significantly reduced Virginia cap may be re-negotiated as early as 2021. In addition to the annual 3% per year reduction, the RGGI model rule includes 2 elements that can reduce the regional cap even further: (1) a banked allowance adjustment, to be determined in 2021 and applied over 2021-25, based on the size of the allowance bank amassed across the current RGGI region over the period 2018-2020; and (2) a new ECR mechanism that would allow the RGGI states to withhold an amount of allowances up to 10% of the statewide emissions budget from offer in the RGGI auction if the auction clearing price falls below the ERC trigger price. The proposal includes both of these RGGI elements that would further reduce the Virginia emissions cap	has been provided upon request to several stakeholders. The commenter correctly notes that the RGGI states conduct periodic program reviews to assess the program. These reviews may result in changes in the emissions caps (either up or down) based on conditions observed in the region.

	beyond the 3% per year reduction already imposed. DEQ's modeling projects an adjustment of 75 million tons to the RGGI regional cap over 2021-25 from the banked allowance adjustment provision. In our original comments, we requested that DEQ explain adjusting the Virginia state emission cap on the basis of banked allowances amassed over the period 2018-2020 (prior to Virginia's linking to the RGGI program) by affected entities in other RGGI states that Virginia affected sources will not be holding since Virginia entities will not become subject to an emissions cap or required to hold allowances until 2020. We therefore advocated that proposed provisions to adjust emissions caps and/or withhold allowances based on the volume of banked allowances should be delayed in the Virginia rule to provide time for a nascent Virginia carbon market to mature. These issues are even more pertinent with the proposed reduced cap. Given these issues, DEQ should defer any decision to modify the originally proposed 2020 baseline emissions cap. To the extent DEQ moves forward with a Virginia cap-and-trade program, it should proceed on the basis of the 33-34 million ton range in the original proposal. An evaluation as to whether adjustments are necessary can be performed during the next RGGI program review (expected to begin in 2021) at which time the impacts of the additional clean energy measures and programs expected to be implemented in the RGGI states including the GTSA in Virginia can be used to inform the effectiveness of the RGGI regional cap as a whole.	
23. Dominion	The revised proposal includes a new provision in 9VAC5-140-6190 C that requires DEQ to review the cap in 2030 and recommend "appropriate adjustments" for post-2030 years. Absent any adjustment, the cap will be reduced (by default) by an additional 840,000 tons/year each year beginning in 2031. This provision	DEQ agrees that participation in the RGGI market must be fully compatible with the existing RGGI program; see current comment 54 for further discussion.

	is premature and unnecessary. The RGGI states conduct a program review every 4 years. On this schedule, subsequent reviews of the program will be conducted in 2021, 2025 and 2029 at which time the effectiveness of the regional program and assessments as to whether "appropriate adjustments" are necessary will be made. The RGGI states themselves note that the re-proposed regulation specifying the additional reductions to the Virginia budget between 2030 and 2040 is inconsistent with the RGGI model rule and that the periodic RGGI program review is the appropriate vehicle to effect changes to the RGGI regional long-term cap trajectory. In addition, § 2.2-4017 of the APA requires agencies to review regulations every 4 years. For these reasons, 9VAC5-140-6190 C should be stricken. At a minimum, the default 840,000 ton per year additional reduction beyond 2030 should be removed.	
24. Dominion	As explained in previous comments, we strongly support DEQ's proposal not to impose any compliance obligations upon units that use biomass as their primary fuel. No emissions attributed to biomass firing should require allowances. This would be consistent with EPA's approach in developing the CPP, which did not include biomass generation in establishing the baseline and state emission reduction targets and did not require biomass units to hold emission allowances under the mass-based model trading rules or surrender emission rate credits under the rate-based model trading rules. This compliance exemption should also apply to the emissions apportioned to the burning of biomass for fossil fuel-fired units that are co-fired with biomass, such as Dominion's Virginia City Hybrid Energy Center (VCHEC). Whether a unit burns biomass as its primary fuel or co-fires biomass with fossil fuel, the emissions from biomass should be treated the same. Under the rule, as currently proposed, a fossil fuel-fired	DEQ agrees that the clarifying language should be restored, and the re-proposal has been modified accordingly (note that the term has also been restored in 9VAC5-140-6040 B). As discussed in greater detail in the initial response to initial comment 67, DEQ recognizes that pollution emitted from biomass-fired plants is a subject of concern for many parties. However, the ED 57 Work Group, EO 11, and the Attorney General's opinion were all expressed in the context of a regulatory process to establish a trading-ready carbon emissions reduction program for fossil fuel-fired electric generating facilities. See also the discussion in current comment 40. DEQ has not taken the position that biomass is carbon neutral, but it has made it clear the applicability of this program is not appropriate for biomass at this time. As a matter of science, forest biomass energy is not carbon neutral and can have other negative environmental impacts. While biomass represents a miniscule fraction of the electricity generation in the Commonwealth, DEQ would view a significant shift toward the

	unit that cofires with biomass would be obligated to hold allowances for all of its emissions (fossil fuel and biomass-based). DEQ seeks comment on whether 9VAC5-140-6050 C 1 should be amended to specify that the total CO_2 emissions related to CO_2 allowances only includes emissions resulting from the combustion of fossil fuel and whether such an amendment to the standard requirements would provide clarity and consistency with the fossil fuel focus of ED-II. 9VAC5-140-6020 C defines "fossil fuel," "fossil fuel fired," and a "CO_2 budget unit." The regulatory requirements for units subject to the rule are established in 9VAC5-140-6050 C. As currently proposed, the rule would require any unit that meets the definition of a fossil fuel-fired unit and a CO_2 budget unit defined in 9VAC5-140-6020 C and the applicability provisions of 9VAC5-140-6040 A to hold CO_2 allowances in an amount no less than the total CO_2 emissions. Thus, a fossil fuel-fired unit that co-fired with biomass (a non-fossil fuel), such as the unit at VCHEC, and meets the applicability criteria of the rule and thus the definition of a CO_2 budget unit would be required to hold allowances for all of its CO_2 emissions including emissions attributed to burning biomass. VCHEC is a 610-MW electric generating station that burns waste coal and co-fires with biomass (it can co-fire with biomass up to 20% of its capacity or 122 MW) as part of its fuel stream using circulating fluidized bed (CFB) technology. CFB is proven clean-coal technology that also enables the using of run-of-mine coal, waste coal, and renewable energy sources such as waste wood. CFB technology combined with modern post-combustion controls yields low emissions of SO_2, NO_X, PM and mercury. In June 2008, the board directed the DEQ to incorporate a provision in the facility's PSD permit to construct and operate in	use of forest biomass for power generation as a negative development. DEQ will be monitoring trends and reserves the right to use existing authority to regulate carbon emissions from biomass in the future.

	accordance with 9VAC5-80 establishing a timetable for biomass utilization at the facility. According to DEQ, the board chose this approach "in order to promote further reductions in SO_2 emissions and show a reduction in carbon emissions, since biomass is considered a biogenic, carbon-neutral material." Requiring VCHEC to now hold allowances under a state carbon program for emissions resulting from the burning of biomass fuel in compliance with an air permit provision established specifically to address carbon is counterintuitive. As currently proposed, the regulation would require VCHEC to hold approximately 8% more allowances than would be required if the rule did not apply to the emissions from biomass. This percentage will increase over the next several years since the air permit requires a stepwise increase in the percentage of biomass fuel up to a minimum of 10%. This will add to the cost of dispatching the unit, which will have direct cost impacts to customers. Requiring fossil units that co-fire with biomass to hold allowances would also be inconsistent with the existing RGGI program which only regulates fossil fuel-fired units. Clarifying language is needed to assure that the limitation of applicability to emissions from fossil fuel would apply to a unit that meets the definition of a fossil fuel-fired unit but co-fires with biomass and that such a unit would not be required to hold CO_2 allowances for emissions associated with the burning of biomass. Accordingly, DEQ should include the clarifying amended language it brought before the Board in September 2018 (shown in brackets) in 9VAC5-140-6050 C 1 and C 2 to preserve the intent of ED-11. C. CO_2 requirements shall be as follows. 1. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for	

	compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions [that have been generated as a result of combusting fossil fuel] for the control period from all CO_2 budget units at the source, less the CO_2 allowances deducted to meet the requirements of subdivision 2 of this subsection, with respect to the previous two interim control periods as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part. 2. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions [that have been generated as a result of combusting fossil fuel] for the interim control period from all CO_2 budget units at the source multiplied by 0.50, as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part.	
25. Dominion	We support the recognition of CO_2 offset allowances from other participating states. However, the re-proposed regulation is ambiguous. It refers to CO_2 offset allowances "generated by" other participating states. This formulation could be misread to limit eligibility to allowances only from projects that are actually located in other participating states. We recommend that the provision refer instead to CO_2 offset allowances "awarded by" other participating states. This alternative language more accurately tracks the language of the offset process in the RGGI Model Rule and in the	As discussed in greater detail in the initial response to comment 26, although the RGGI model rule does offer states the option to award offset allowances for projects outside of the electric power generation sector, only a single offset project has been implemented in the entire RGGI region since the program's inception. One of the reasons offsets have been little used in RGGI is the low allowance prices to date. It appears that regulated entities have had little need to use offset allowances to date. Should this change, the need for an offsets program in Virginia can be revisited at a later date. Additionally, the board's ability to address transportation sector emissions is limited

	regulations promulgated by other participating states. Further, it makes clear that DEQ will recognize CO_2 offset allowances awarded by a participating state, even if the underlying project is located in another state. The RGGI Model Rule has authorized a pathway for awarding CO_2 offset allowances in such circumstances. The process, which has been adopted by other participating states, involves entering into a memorandum of understanding with the non-participating state. The proposal includes the establishment of an arbitrary restraint on offsets in the proposed program. It would deny the opportunity for projects located in Virginia to earn CO_2 offset allowances. Under the proposed approach, Virginia-based projects not only could not apply to Virginia for CO_2 offset allowances, they also could not apply for CO_2 offset allowances from other RGGI participating states. Under the RGGI Model Rule and corresponding participating state regulations, a project is only eligible to receive CO_2 offset allowances from the state in which the majority of reductions occur. Accordingly, a Virginia-based project could not apply to other participating states that award CO_2 offset allowances to projects. Rather, the door would be closed to Virginia-based offset projects, including projects that could otherwise meet the eligibility criteria of the RGGI program. We urge DEQ to revisit this approach and open the door to worthy projects from Virginia. By making it possible for projects in the state to earn offset allowances, DEQ would make it possible for a greater number and variety of Virginia entities to participate in the state's efforts to address climate change. The program would provide incentives for mitigation activities and technological innovation across additional sectors, including the agriculture, manufacturing, and transportation sectors. At a minimum,	by statute. Given the uncertainty of any benefits associated with a complex offset program, DEQ will not, at this time, implement the offset option.

	DEQ should allow for projects deemed eligible under the RGGI model rule. In particular, there is great potential for offset projects in Virginia's agricultural sector, including projects that capture waste methane from hog farms and convert it into renewable natural gas (RNO) that can heat homes and provide power to local businesses. By capturing methane that would otherwise be released into the atmosphere, the use of RNO leads to a significant reduction in methane emissions. Allowing Virginia projects to earn CO_2 offset allowances and allowing a CO_2 budget source the flexibility to meet a limited portion of its compliance obligation with offset allowances also would moderate the costs of compliance with the program and the resulting impacts on ratepayers and consumers. Offset projects expand the universe of emission reduction activities that can be used for compliance, including activities that could have a lower per-ton cost than measures implemented at CO_2 budget sources. The compliance cost flexibility offered by offsets will be important in the RGGI program as its stringency increases. In the past, offsets have played only a small role in the RGGI program. However, the RGGI states, including Virginia, have committed to emissions caps in 2020 and beyond that are significantly more ambitious than the caps that have applied to date. Already, the RGGI allowance market is adjusting to this expected trajectory of more stringent limits. The first RGGI allowance auction in 2017 had a clearing price of $3.00. By the December 2018 auction, the clearing price was $5.35, a 78% increase. Another indicator of the growing demand for RGGI compliance instruments can be found in the futures market. The RGGI market monitor has determined that the overall volume of futures trading in the third quarter of 2018 was up 55% from the previous quarter, and 36% higher than the third quarter of the	

	previous year. The market monitor also found that options trades in the third quarter of 2018 had strike prices at $4.50 for December 2018 options, rising to $6.00 for December 2019 options. And these trades predated DEQ's proposal to substantially tighten the emissions cap for Virginia. In other words, all indicators point to rising prices for allowances, and therefore higher compliance costs. These are conditions for which offset projects would provide a significant cost-mitigating influence. These conditions suggest that demand for compliance instruments in the RGGI program could increasingly approach the demand in jurisdictions participating in the WCI. In those jurisdictions, ambitious emissions caps have yielded significant demand for offset credits, even though the economy-wide scope of the cap-and-trade program means that regulated entities can draw on reductions from multiple sectors; and there are strict limits on the amount of offset credits that regulated entities can use for compliance. California's compliance offset program alone has approved over 370 projects and issued over 140 million offset credits. Without those credits, allowance prices and resulting compliance costs would have been significantly higher. In 2010, CARB modeled how the state's cap-and-trade program would perform by 2020 under various scenarios, including a case in which the cap-and-trade program did not allow the use of offsets. CARB's modeling found that the allowance price in 2020 under its base case (the cap-and-trade program with offsets) would be $25/t$CO_2$e. In the case of the cap-and-trade program without offsets, the price was $148/t$CO_2$e. The WCI experience makes clear that there are significant risks to imposing arbitrary limits on the scope of offset projects that can generate CO_2 offset allowances. Importantly, offsets are a cost containment mechanism that ensures	

	that the cap-and-trade program can continue to deliver expected environmental benefits. Offsets are an important complement to the CCR, which is designed to help prevent allowance prices from exceeding unreasonable and unmanageable levels. The CCR achieves this by making additional allowances available in the RGGI allowance auction at the CCR trigger price thereby increasing the emissions cap in response to a price spike. By contrast, the offsets mechanism contains costs by expanding the universe of emission reductions that can be used for compliance purposes, without increasing the emissions cap. The two cost containment mechanisms can work well together. By making it possible for a CO_2 budget source to use CO_2 offset allowances to meet a portion of its compliance obligation, the program makes it less likely that allowance prices will spike to the level of the trigger price and thereby relax the emissions cap. In other words, offsets can ensure that activation of the CCR is the last resort that it should be. Denying eligibility to state-based projects would not only jeopardize the cost containment benefits of offsets; it would also deny Virginia other important benefits delivered by offset projects. These include air and water quality improvements as well as new jobs. Indeed, DEQ's proposed approach is the inverse of the approach adopted in the WCI. California mandates that at least half of the credits that a covered entity submits for compliance come from projects that provide "direct environmental benefits in the state." By contrast, DEQ's proposed approach effectively establishes a preference for other states to enjoy these co-benefits. DEQ said that one of the reasons not to promulgate rules and procedures to award offset allowances to Virginia projects is that an offset program is	

	"complex" to manage. Yet DEQ already has long experience with offsets programs. The General Assembly expressly authorized DEQ to assess and issue credits to offset projects, and DEQ has exercised this authority for many years in the context of the federal Clean Air Act. Given this experience, DEQ is certainly no less capable of managing a CO_2 offsets program than the 7 other RGGI states that have agreed to review in-state projects, and New Jersey intends to join their ranks. There is no good reason for Virginia to be an outlier among participating states. To address any complexities, DEQ can draw on the extensive experience of other jurisdictions that have managed carbon offset programs. CARB has expanded its administrative reach by using private, non-profit offset project "registries" to do some of the initial work of project documentation review. For these reasons, there are no meaningful legal or administrative barriers to DEQ implementing Virginia-based offset projects. Given the increasing stringency of the Virginia emission caps and the RGGI program as a whole, we urge DEQ to expand the scope of eligible offset projects to include projects that reduce sulfur hexafluoride (SF_6) in the electricity transmission and distribution sector. Such projects reduce highly potent GHG emissions not otherwise covered by RGGI emission caps. According to the United Nations, the global warming potential of SF_6 is 23,900 times as great as carbon dioxide over a 100-year period. Once emitted, SF_6 remains in the atmosphere for 3,200 years. Entities in the power sector do not have legal requirements to reduce SF_6 emissions, and there are no meaningful economic gains from such projects. Accordingly, such activities meet the "additionality" criteria for offset projects. SF_6 reduction projects are well understood, with well-established methodologies for measurement and verification. An	

	earlier version of the RGGI Model Rule included SF_6 projects on the list of eligible project types. The combination of low demand and high administrative costs discouraged the development of SF_6 projects for RGGI purposes. As discussed above, however, there is every reason to expect substantially greater demand for offsets in the RGGI states in the future, which provides a reason for DEQ to revisit and streamline the rules and procedures for SF_6 projects. We urge DEQ to establish the eligibility of projects that reduce CO_2 emissions in the transportation sector through electrification, including development of charging infrastructure. Across the U.S., transportation sector CO_2 emissions now exceed those from the power sector, and are continuing to increase. Rising transportation sector emissions complicate the efforts of Virginia and other states to achieve climate policy objectives. A number of studies have concluded that it will only be possible to achieve decarbonization objectives for the transportation sector through electrification of much of the sector. Electrification, in turn, will only be possible through a build out of charging infrastructure. Electric vehicles are becoming an attractive choice for more consumers; however, potential buyers identify the lack of charging stations as a major obstacle. State incentives can playa key role in this necessary build-out of charging infrastructure. Furthermore, utilities are well positioned to lift the market for charging infrastructure off the ground. Utilities can offer experience with infrastructure development, the benefits of grid coordination, expertise with customer pricing models with the grid, and experience developing services for disadvantaged communities. For these reasons, we recommend DEQ create a market-based incentive for charging station development by owners of CO_2 budget sources in the form of CO_2 offset allowances. The CO_2 offset	

	allowances would correspond to the CO_2 emission reductions attributable to the electricity provided by the station to electric vehicles, which would displace the use of higher carbon-intensity gasoline that conventional vehicles would otherwise use. This incentive mechanism would give Virginia a jump start on its development of policies under the Transportation and Climate Initiative.	
26. Dominion	The deadline in 9VAC5-140-6215 C 1 for affected entities to submit initial generation output data (2016-2018) to DEQ for the initial 2020 allocation determination needs to be extended. The March 1, 2019 date will certainly precede any date for which the regulation, if finalized, would become effective. The submittal deadline for initial generation output data should be changed to 60 days after the effective date of the regulation. Likewise, the May 1, 2019 deadline for DEQ to submit to the auction agent conditional allowance allocations for the initial 2020 control period in 9VAC5-1400-6210 H 1 must be extended at least 60 days after the deadline for submittal of the initial generation output data specified in 9VAC5-140-6215 C 1.	These corrections are acceptable, and the proposal has been amended accordingly.
27. Dominion	The change below in brackets is needed in 9VAC5-140-6420 A 2, which specifies the number of CO_2 CCR allowances that would be offered for sale during an auction, in order to provide the intended citation to the conditions that would trigger the CCR provisions. "The number of CO_2 allowances that will be offered for sale at the auction if the condition of [B] 1 of this subsection is met. . . "	This correction is acceptable, and the proposal has been amended accordingly.
28. DuPont, Veolia	DuPont owns and operates the Spruance Plant, a large manufacturing facility that is interconnected with an adjacent cogeneration plant that provides steam to the plant. DuPont has recently entered into a long-term agreement with Veolia to operate and maintain the cogeneration facility. Veolia is significantly modifying the cogeneration plant to convert the fuel from coal to natural gas, as well as	Support for the proposal is appreciated.

	performing other efficiency upgrades. After the modifications, the electricity generating capacity of the cogeneration plant will be reduced and it will primarily operate as a steam plant that makes only a small amount of electricity. Chief among the prior DuPont comments on the original proposal was a request that the industrial exemption contained in that initial draft regulation be clarified and broadened to better reflect the realities of industrial power generation. DuPont is pleased that DEQ took the time to address the public comments about the industrial exemption concept and for the reasons set forth below, DuPont supports the regulation as re-proposed. The regulation provides two paths to qualify for the industrial exemption and introduces the concept of "total useful energy," which includes either electrical energy or thermal energy. The conditions that allow an entity to qualify for the industrial exception are: 9VAC5-140-6040 B. The addition of the second standard involving a threshold on total useful energy rather than just electrical generation is the key to addressing the concerns of a facility like the Spruance Plant. At this plant most of the energy generated and used by the plant is thermal, but 100% of the electrical production (which is a small amount of the overall energy production) is supplied to the grid. DuPont has consulted with Veolia and confirmed that the cogeneration plant can meet the less than or equal to 15% standard. We also appreciate DEQ broadening the scope of tile industrial exemption by removing the previous language requiring that the industrial facility and the power-generating unit serving the facility had to be under common ownership in order to qualify for the exemption. The new standard provides flexibility for operating	

	arrangements when the power-generating unit and the industrial facility have been split up to gain operational and economic benefits. DuPont appreciates the work DEQ has done to complete the regulation and supports Virginia's goal of achieving meaningful reductions in GHG emissions.	
29. Environmental Defense Fund (EDF)	As discussed in our comments on the original proposal, the board has ample existing statutory authority to adopt a cap-and-trade program that reduces statewide emissions of GHG. We incorporate those comments by reference and discuss in further detail why key aspects of the re-proposal are also well supported from a legal perspective. The board's proposed set-aside comports with its statutory authority. The board has specified that the proceeds from set-aside allowances will fund "the implementation of programs that lower base and peak electricity demand and reduce the cost of the program to consumers and budget sources." The agency would be well within its statutory authority to adopt a rule that includes a set aside of this nature. The board has broad authority under § 10.1-1308 of the Air Pollution Control Law of Virginia to promulgate regulations abating, controlling and prohibiting air pollution throughout the state. An allowance set aside designed to reduce greenhouse gas emissions would "abat[e] . . . air pollution" if the allowance allocation supported emission reducing projects within DMME's purview, such as deploying energy efficiency and renewable energy. In the final rule or in implementing the rule, the board or DEQ, in collaboration with DMME, should specify the factors by which projects will be evaluated for allowance allocation and demonstrate their potential to abate air pollution to protect human health, welfare, and safety, protect the environment, and promote economic development.	Support for the proposal is appreciated, as is the commenter's discussion of the legal authority to proceed with this action. As discussed in the current response to current comment 11, implementation of the set-aside will be developed by DMME in accordance with its regulations and policies. The CCR is designed to be consistent with the RGGI CCR, and no changes to the set-aside or the CCR mechanism are necessary.

	The board's broad authority to mitigate air pollution and to design air pollution policies to serve a diverse set of statutory directives under § 10.1-1308 is made clear by § 10.1-1306, which instructs that the board: "shall make, or cause to be made, such investigations and inspections and do such other things as are reasonably necessary to carry out the provisions of [Code of Virginia, Title 10.1, Subtitle II, Chapter 13], within the limits of the appropriations, study grants, funds, or personnel which are available for the purposes of this chapter, including the achievement and maintenance of such levels of air quality as will protect human health, welfare and safety and to the greatest degree practicable prevent injury to plant and animal life and property and which will promote the economic and social development of the state. Under this mandate, the board must act to protect the public from air pollution and weigh, in designing air pollution reduction policies, opportunities to further economic and social development of the state. Allocating a portion to support energy efficiency projects, which will both reduce emissions of greenhouse gases and other harmful air pollutants and reduce the cost impacts of the emission reduction program, furthers the statutory mandate to abate pollution and supports economic development at the same time. Thus, the proposed set aside for energy efficiency projects is well within the board's statutory mandate. We urge the board to clearly provide that the set aside allowances could be allocated to a variety of projects that would reduce emissions and facilitate greater emission reductions going forward, such as renewable energy projects. DEQ would "allocate 5.0% of the Virginia CO_2 Budget Trading Program base or adjusted budget allowances, as applicable, to DMME to be consigned to auction by the holder of	

	a public contract with DMME to assist the department for the abatement and control of air pollution, specifically CO_2, by the implementation of programs that lower base and peak electricity demand and reduce the cost of the program to consumers and budget sources." The board may include in its regulation criteria and other requirements for DMME to apply in contracts with a third-party administrator based on its authority to "cooperate with . . . all agencies of the Commonwealth . . . in furtherance of the purposes of this chapter." Possible criteria for project selection could include the quantity and type of emission reductions that the project is likely to achieve, the time within which the project will likely achieve emission reductions, the cost-effectiveness of the project, economic benefits, and the potential for the project to support mitigation of air pollution and energy costs in at-risk communities. The implementing regulations should provide for projects to report on the emission reductions achieved as well as the achievement of any other projected benefits. The regulations should further ensure that projects and project developers that upon review fail to deliver emission reductions or other benefits due to what DMME determines to be avoidable failures by the project developers be made ineligible for allowances or otherwise subject to heightened scrutiny going forward. We also recommend that if any allowances from the set-aside are not used, they become additional CO_2 CCR allowances. The purpose of the set-aside and the allocation of allowances to DMME is to "assist the department for the abatement and control of air pollution." Given this purpose, if DMME is unable to use the allowances, we recommend that the set-aside allowances become part of the CO_2 CCR allowances because that would ensure that these allowances will still serve the purpose	

	of abating and controlling air pollution by reducing emissions unless the CCR trigger price is met, in which case they will promote the statutory purpose of economic and social development of the state by controlling costs.	
30. EDF	The board would be well justified in establishing an initial base budget of 28 million tons of CO_2. The proposed rule originally sought comment on whether the initial base budget should be 34 or 33 million tons of CO_2; the board has revised that number to 28 million tons. This adjustment would, relative to the originally proposed budgets, better fulfill the board's statutory duty to "achieve . . . such levels of air quality as will protect human health, welfare and safety and to the greatest degree practicable." Setting the base budget at a level that reflects this statutory mandate is particularly important because incremental reductions from the initial budget that must be met in future years are determined relative to this initial emissions budget. The evidence before the board in the record already compiled--including DEQ modeling--indicates that the initial base budget must be revised downward in order to fulfill board's statutory obligations. While modeling is not necessarily a perfect predictor of what will happen in the future, it does provide important insights into likely trends and future outcomes that can appropriately inform this decision. Recent modeling updates show lower emissions in 2020 than DEQ originally projected, along with trends indicating continued emission reductions from Virginia's power sector. We discussed several such findings in our April 2018 comments on the original proposed rule. Since then, DEQ released new IPM modeling--using appropriately updated assumptions about natural gas prices, electricity demand growth, and emission reductions projections from increased renewables and energy efficiency development under the GTSA--that supports projections of a lower 2020 emissions baseline.	Support for the proposal is appreciated, particularly the discussion of the appropriateness of the new baseline cap. See also the discussion in the initial response to initial comment 37.

	Modeling from Rhodium Group, using a modified version of the National Energy Modeling System with updated assumptions, also projects lower 2020 baseline power sector emissions than previously projected for Virginia. These findings indicate that a 2020 base budget of 28 million tons of CO_2 is appropriate. The proposed revision to the 2020 initial budget, by responding to the data submitted by stakeholders and the analysis by the agency itself, is appropriately fact-based and reasonable rulemaking in accordance with the principles of administrative law. EDF is currently modeling state and regional electric sector CO_2 emission outcomes (through 2030 and beyond) under a range of policy scenarios. Preliminary results from the modeling indicate that under business-as-usual conditions, electric sector CO_2 emissions in Virginia could continue to increase significantly above the proposed base budget by 2030. Thus, we anticipate that Virginia's adoption of a CO_2 budget trading program with the proposed CO_2 emission budgets would result in critical CO_2 emission reductions.	
31. EDF	Analysis from RGGI indicates that leakage effects--the potential increase in CO_2 emissions from generators outside the RGGI region due to shifting generation from covered sources as a result of the RGGI carbon price--are likely to be much smaller than the substantial environmental benefits of Virginia's program. Nevertheless, we urge the board to adopt a rule that takes steps to mitigate any significant leakage that may occur because doing so would further the statutory purpose of protecting health and welfare. DEQ names several reasons why leakage is unlikely in its responses to comments on the original proposed rule. In part, DEQ explains, "the owners of generation in Virginia are unlikely to face any competitive disadvantage relative to plants	As discussed in the initial response to initial comment 91, neither DEQ nor RGGI anticipate leakage issues. Regardless, the program will be closely monitored by both Virginia and RGGI to assure that this continues to be the case. DEQ appreciates the commenter's concerns, but points out that there are multiple layers of monitoring and reporting that will be ongoing for the lifetime of the program. Note that RGGI monitors for and reports trends in leakage annually; see, for example, the most recent "CO_2 Emissions from Electric Generation and Imports in the Regional Greenhouse Gas Initiative: 2015 Monitoring Report." Although a slight increase in imports of electricity is projected in the IPM modeling, this modeling is conservative in that it does not take into account the

	outside the state because the allowances are to be allocated to compliance entities under the program, and the amount of the allocations are to be determined on an updating output basis." Moreover, "updating output-based allocation is expected to encourage generation in the state, rather than discourage it" DEQ also writes, "The implementation of the DMME set-aside will also encourage the reduction of in-state demand, thereby reducing carbon pollution and further preventing leakage." We agree that the updated output-based allocation and the efforts to reduce in-state emissions through the set-aside should reduce leakage and may be sufficient mechanisms to address leakage, but urge DEQ to include its assessment of leakage risk and strategy for mitigating the risk in the official record for the final rule, as well as a commitment to monitor leakage going forward and to take steps to address significant leakage if it is observed. Specifically, EDF also urges DEQ to provide within the final rule a detailed explanation of the measures Virginia is taking and will take to mitigate the potential for leakage. In particular, EDF supports the proposal to evaluate leakage as part of the periodic program review process. We also encourage DEQ to work with RGGI states to monitor and analyze power flows and emissions from RGGI and non-RGGI generating sources for signs of leakage as part of RGGI's annual electricity monitoring process, and to work with other RGGI participating states to evaluate and adopt mechanisms to effectively address leakage in the periodic region-wide program review. Further, Virginia should also consider (now or in the future) extending the carbon cap to account for emissions attributed to electricity imports into Virginia. This approach would likely be the most effective mechanism to mitigate leakage, as it ensures that any emissions associated with generation dispatched to serve	updating, output-based allocation approach. This allocation approach has been shown to reduce the pressure to import electricity by rewarding in-state generation. (See current response to current comment 19.) Also note that carbon intensity in the region is decreasing, and carbon pollution effects from any increase in imports are therefore likely to be minimal. See, for example, current comments 19 and 46.

	electric load in Virginia will be covered by the cap, eliminating any economic incentive for uncovered generating units from out-of-state to serve Virginia load. Accounting for carbon emissions associated with imported electricity under the cap ensures statewide emission reductions, while mitigating any market distortion between units serving the same load. Virginia should engage with RGGI and PJM states to explore and pursue the development of strategies within the PJM market region to provide the state with the information it would need to deploy such a solution.	
32. EDF	EDF supports DEQ's proposal to use an updating output-based approach to allocating conditional allowances to covered sources. Analyses conducted by EDF and RFF in the context of the federal CPP found that using an updating output-based approach can be an effective means of mitigating emissions leakage. Modeling conducted by RFF found that using an updating approach to allocate 100% of allowances to a subset of eligible sources under the CPP (as opposed to a historic, "grandfathering" approach) could reduce leakage by up to 64% compared to a mechanism that allocated only 5% of allowances with an updating output-based approach. Similarly, EDF analysis found that allocating all or nearly all CO_2 allowances with an updating output-based approach could significantly reduce leakage compared to alternative approaches.	Support for the proposal is appreciated. DEQ particularly acknowledges the observation that the updating output-based approach will likely minimize any leakage.
33. EDF	EPA defines environmental justice as, "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies." A regulatory process that prioritizes meaningful involvement and secures outcomes that ensure no community is disproportionately harmed--and that underserved communities receive an equitable share of the benefits--is a vital goal. It is important to note that	Support for the proposal is appreciated. It is important to note that Virginia will be the first RGGI member state to explicitly incorporate consideration of environmental justice issues in its RGGI regulatory program. As discussed in greater detail in the initial response to initial comment 55, DEQ has a robust community involvement program, and the addition of environmental justice review and analysis in this regulation builds on this important commitment. This commitment is buttressed by ongoing RGGI and state-

	finalizing the program with an environmentally protective emissions budget that declines over time consistent with best available science and modeling is vital to advancing environmental justice. Fossil fuel-fired power plants tend to be disproportionately located in or near communities of color and low-income communities. Moreover, according to the U.S. Global Change Research Program's Fourth National Climate Assessment: "Social, economic, and geographic factors shape the exposure of people and communities to climate-related impacts and their capacity to respond. Risks are often highest for those that are already vulnerable, including low-income communities, some communities of color, children, and the elderly. Climate change threatens to exacerbate existing social and economic inequalities that result in higher exposure and sensitivity to extreme weather and climate-related events and other changes." By reducing CO_2 and co-pollutant emissions across the board, a stringent emissions budget can benefit communities that tend to bear disproportionate harms. EDF welcomes the board's commitment to evaluate potential impacts of the program on vulnerable and underserved communities. The program will be one of a broad set of policies and programs that potentially affect environmental justice issues in the state. Analyzing the potential impacts of RGGI on vulnerable communities will be an important part of the broader suite of actions Virginia agencies are taking to address environmental justice. EDF urges the board to prioritize meaningful involvement of environmental justice communities and experts in developing and executing a robust and transparent environmental justice analysis. The board should work closely with community stakeholders to define the scope of the analysis, methodology, outreach strategy, and	required program reviews, which will provide multiple opportunities for public review and participation.

	actionable steps to strengthen the program and mitigate environmental justice effects.	
34. EDF	The regulation should require any base budget allowances that are not allocated to be added to the total conditional CCR allowances. This will help ensure the program's emission reduction and cost containment goals are met. It can be accomplished by adding the following provision to section 9VAC5-140-6070 of the regulation as subsection B and making the existing language subsection A: B. Notwithstanding 9VAC5-140-6070 A, any Virginia base budget allowances that are not allocated pursuant to the valid provisions of this regulation shall be added to total conditional CCR allowances for the appropriate calendar year listed in 9VAC5-140-6200 and allocated accordingly. As discussed in our comments on the original proposed rule, EDF supports the inclusion of the RGGI price floor and ECR. These are important features of RGGI to ensure proper functioning of the CO_2 allowance market and provide opportunities to drive additional emission reductions if compliance costs are lower than anticipated. EDF also supports the proposed changes to clarify the allocation formula and function of the CCR.	Support for the proposal is appreciated. DEQ agrees that the price floor, CCR and ECR will enable the program to continue to function properly.
35. EDF	The 2021 adjustment for banked allowances would lower the RGGI cap for 2021-2025 to account for banked allowances in excess of 2018-2020 emissions from RGGI covered sources. The adjustment is apparently intended to preserve stringency of the RGGI cap in future years by guarding against an excess of allowances in the bank--while not unduly penalizing sources for abating emissions early. In Virginia, CO_2 Budget Sources will not face a compliance obligation until 2020--and therefore have no incentive to bank allowances until then. The board should accordingly revise Virginia's contribution to the RGGI 2021 bank adjustment by accounting	The bank adjustment process is a fundamental component of the RGGI program and Virginia's participation in the adjustment is necessary to keep the Virginia program consistent and viable with the RGGI program. Therefore, the Virginia program is designed to be as compatible and consistent with the RGGI program as possible, including the treatment of banked allowances. The commenter correctly describes the effect of the bank adjustment and this effect was well known in the development of the proposal. The bank adjustment changes the number of emissions allowances in circulation and therefore the stringency of the program. The IPM

	for banked allowances in excess only of 2020 emissions from Virginia CO_2 budget sources.	modeling took the bank adjustment into account. Because the proposal is to link to the larger RGGI program, participating in the bank adjustment while taking into account its impact on program stringency in Virginia was the most prudent approach to ensuring that the proposal could be linked to the larger RGGI program, bringing to Virginia all of the benefits that linking provides.
36. EDF	The board should take steps to ensure CO_2 emissions from the power sector decline to zero before mid-century. EDF welcomes the board's commitment in the re-proposed rule to, at minimum, continue annual tonnage reductions through 2040 and encourages the board to consider steeper reductions beyond 2030 to ensure the power sector is nearly or fully decarbonized by 2040. This provides critical long-term certainty around carbon regulation for regulated facilities and others doing business in Virginia--and this market certainty will contribute to a successful and robust emissions market, and can also help ensure Virginia is at the table as a leader on climate policy in the future. We also support DEQ's commitment to engage in RGGI program review processes in order to continue to evaluate where Virginia needs to go beyond 2030, in concert with the other RGGI states. As we discussed in our earlier comments, it would be prudent for the board to work with other RGGI states to act sooner rather than later to reduce emissions more quickly in the near-term, in order to minimize economic costs and secure the greatest environmental benefits. The need for Virginia to continue reducing carbon pollution from the power sector beyond 2030 to zero emissions before mid-century remains urgent. The 2018 report from the Intergovernmental Panel on Climate Change notes that a key characteristic of the 1.5°C mitigation pathways include "strong upscaling of renewables and sustainable biomass and reduction of unabated fossil fuels,	Concerns about ongoing carbon reductions are well taken, and DEQ agrees that program needs beyond 2030 must be addressed. However, participation in the RGGI market must be fully compatible with the existing RGGI program, and requiring specific reductions through 2040 conflicts with RGGI's well-established and well-functioning collaborative process and program review process; see current comment 54 for further discussion.

	along with the rapid deployment of CCS, [which] lead to a zero-emission energy supply system by mid-century." In our comments on the proposed rule, we wrote, "A number of recent studies suggest that in order to limit global temperature increases to less than 1.5°C or 2°C above pre-industrial levels, global carbon dioxide emissions must reach net-zero by mid-century." Recent landmark findings from the Intergovernmental Panel on Climate Change (IPCC) and U.S. Global Change Research Program suggest emissions must decline at an even faster rate to avoid catastrophic impacts of climate change. Specifically, the IPCC finds that global warming 1.5°C above pre-industrial levels will result in dramatic, harmful impacts to human health, U.S. and global economies, and the environment. In addition, as we also described in our earlier comments, Virginia could leverage readily available emission reduction measures to cut carbon pollution from the power sector at a faster rate. A steeper rate of decline in the trading program than the 3% of the 2020 budget per year currently proposed could facilitate the more rapid emission reductions in the power sector that are needed to achieve our climate goals. Revising the power sector CO_2 budget downward to match or exceed the reduction trajectory charted by the IPCC would unlock opportunities for other sectors to reduce emissions at lower cost and at a faster pace via electrification — providing greater certainty that Virginia will cut climate pollution from across the economy at the scale and level of ambition required to avoid catastrophic climate change impacts.	
37. EDF	DPB's Economic Impact Analysis of the re-proposal included analysis that showed Virginia electricity consumers will see lower average monthly electricity bills with the re-proposal policy in place versus the reference case without it. This is consistent with independent analysis of the broader RGGI program. A 2018 report by	Support for the proposal and for the supporting economic analyses developed for this regulatory action is appreciated.

	Analysis Group, for example, found that in the RGGI region consumers' electricity bills go down over time, due in part to investments in energy efficiency. Another analysis found that average electricity prices decreased by 6.4% in the RGGI region since the inception of the program.	
38. National Alliance of Forest Owners (NAFO)	As Virginia's third largest industry, forestry is a critical economic force. According to The Economic Impact of Virginia's Agriculture and Forest Industries, "the forestry sector had a total impact of over $21 billion in total output, approximately 107,900 jobs, and $9.3 billion in value-added." This annual economic contribution in large part depends on Virginia's 15.72 million acres of forestland, of which more than 13 million are privately owned working forests. State policies that incentivize the use of biomass as a prioritized alternative fuel source provide a market for lower value or underutilized timber and harvest residues as well as residuals from manufacturing; consequently, such policies deliver a valuable economic rationale for private forest owners to keep lands forested. Generating and selling biomass fuel components from privately owned Virginia forestland will support these forest owners in the state and continue to develop a carbon-neutral fuel source in a state already committed to moving beyond a traditional fossil fuel-powered infrastructure. In Virginia, harvest residues such as tops, limbs, and undersized stems, are often chipped in the field to generate mixed chips, which are then sold to power generation facilities to produce heat or electricity. These mixed chips are supplements to mill residues and other used wood materials that can be burned to generate power. According to the Department of Taxation and the Department of Forestry, mixed chips produced in 2015 and 2016 represented approximately 19% of the total cubic feet of Virginia forest products generated in those years,	Although DEQ recognizes the importance of the forest product industry, DEQ is also aware of air quality issues related to the combustion of biomass, and is not attempting to definitively regulate or establish a specific policy for biomass combustion with this regulatory action. Nonetheless, as discussed in greater detail in the initial response to comment comment 67, DEQ is adhering to the specific requirements of ED 57, EO 11, and RGGI, and limiting this particular regulation to fossil fuel-fired facilities. As more fully discussed in the current response to current comment 40, the board amended the initial proposed regulation, while the initial Agency Background Document (including the initial response to comments) reflected DEQ's original position. This document has been corrected, and the regulation has been amended based on the re-proposed public comment received. DEQ believes that the restoration of the original language related to fossil fuels adequately demonstrates their exemption from the rule. Reducing the fossil fuel threshold from 10% to 5% is needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program. Adding a specific definition of biomass as the commenter requests may have the unintended consequence of creating or removing applicability of certain projects beyond what the commenter currently anticipates. DEQ believes that the simple limitation to fossil fuel is clear and appropriate.

	with the remainder being the actual logs harvested for pulp and wood manufacturing. While mixed chips are the lowest-value forest products, they represent an important source of income for private forest owners. Making clear in the final regulation that biomass emissions are excluded from the carbon dioxide accounting requirements will help to further encourage development of this robust and competitive biomass market in Virginia. A majority of states that participate in the RGGI carbon trading system fully exempt biomass from the program. Aligning on this policy issue with other RGGI states will encourage Virginia electricity generating facility owners and other industrial sources to avail themselves of the abundant biomass products sustainably harvested in the state. Moreover, excluding biomass from the final rule will provide a more economical fuel alternative to facility owners. Exempting biomass will incentivize co-firing, and thus provide access to a readily available, Virginia-based fuel without the additional cost burden of obtaining CO_2 allowances that will be imposed on carbon emissions from fossil fuels. NAFO urges DEQ to fully and explicitly exempt biomass emissions from co-firing operations in the final RGGI regulations. NAFO is concerned the text of the re-proposed regulations does not implement the policy position stated in the preamble and DEQ's response to comments on its earlier proposed rule. In its October 2018 response to comments, DEQ stated it would amend the proposal to indicate that a CO_2 allowance is a limited authorization to emit up to one ton of CO_2 that has been generated as a result of combusting fossil fuel. In the response to comments, DEQ made plain its intent to define "CO_2 allowance" to be "a limited authorization by the department or another participating state under the CO_2 Budget Trading Program to emit	

	up to one ton of CO_2 that has been generated as a result of combusting fossil fuel." Although the proposed regulation did not otherwise define biomass, limiting the rule's coverage to emissions generated "as a result of combusting fossil fuels" would provide clarity – as it would thereby explicitly exempt non-fossil fuel emissions from regulation. The preamble to the re-proposed regulation follows the statement in DEQ's response to comments and confirms DEQ's intent to explicitly exempt biomass emissions from the regulations. As DEQ stated: "Other substantive changes in the reproposed action include … exemption of fossil fuel units that co-fire with biomass from CO_2 accounting…." However, the published definition of CO_2 allowance does not include the critical limitation of "as a result of combusting fossil fuel." Omitting this language undercuts DEQ's intent to codify the biomass exclusion in the final regulation. DEQ should reincorporate into the definition of "CO_2 allowance" the limiting language of "CO_2 that has been generated as a result of combusting fossil fuel" in order to effect DEQ's decision to substantively "exempt[] …fossil fuel units that co-fire with biomass from CO_2 accounting." While revising the text would provide clarity, DEQ should consider providing an affirmative definition of biomass in the final regulations. As discussed in our earlier comments, the Virginia Legislature has already provided such a definition of biomass in the state code. Defining "biomass" similarly and excluding it from the regulation, rather than by implication, would provide further clarity. Defining biomass and then excluding emissions from biomass from the rule would also be consistent with both the RGGI model rules and most other RGGI states. Finally, as discussed in our earlier comments, DEQ should also consider revising the definition of "fossil fuel-	

	fired" to change the threshold of fossil fuel burned from "5% or more" back to "10% or more." Excluding entirely from the regulations facilities that burn 90% or more, rather than 95% or more, of biomass as their primary fuel source better reflects the policy that biogenic emissions are fundamentally distinguishable from fossil fuel emissions. Virginia should be encouraging this important economic engine for the state's economy, rather than restricting the standards for future development of near biomass-only facilities.	
39. Natural Resources Defense Council (NRDC)	NRDC's IPM modeling, conducted by ICF, predicts the same Virginia emissions in 2020 as that indicated by DEQ's own analysis: NRDC's IPM modeling for Virginia projects the state's power sector emissions to be 28 million tons in 2020. This modelling accurately reflects the reality of today's power sector in Virginia. First, in-state coal units no longer compete on the open market, and thus no longer have an outsized impact on statewide emissions under business-as-usual conditions. Specifically, only one Virginia coal plant exceeded a 40% capacity factor in 2018 (VCHEC, at 54%). As such, coal units now account for less than 10% of Virginia's annual generation. Meanwhile, renewable energy installations, most notably solar energy, are steadily increasing. In 2018, Virginia's solar capacity grew by 158%, the fourth-highest in the nation. This is largely due to the steady decline in the cost of renewables, with utility scale solar costs falling 13% last year (on top of an 88% drop in the past nine years). The steep decline in coal generation and renewables costs is concurrent with lower demand growth projections across the state and region. As a result, the U.S. EIA's Annual Energy Outlook 2019, for example, anticipates carbon emissions in the Virginia-Carolina region will already decrease by 35% from 2017 levels by 2021. Combined, the factors of lower in-state electricity demand growth, persistently declining gas prices, and	Support for the proposal and the discussion of the appropriateness of the new cap is appreciated.

	growing low-cost renewables (and their impact on coal's ability to compete in the marketplace), make 28 million tons a sensible starting point for the program, one that reflects the reality of today's energy marketplace. A sufficiently ambitious program will also drive significant economic and health benefits, including lower energy bills and rates, as well as improved public health resulting from cuts in co-pollutants like NO_X and SO_2.	
40. NRDC	DEQ's proposed rule clearly requires that co-firing facilities hold allowances for the CO_2 they emit, whether those emissions be from forest-derived biomass or fossil fuels. While Governor Northam unexpectedly removed coverage of biomass co-firing emissions in the version presented to the board in October 2018, the board rightly voted to remove that newly-inserted exemption of biomass co-firing. (Note that DEQ inaccurately describes an "exemption of fossil fuel units that co-fire with biomass" in the summary of the regulation, a description that is at odds with the wording of the regulation and the intent of the board.) The board's inclusion of biomass co-firing under the rule is sensible and reasonable. Forest-derived biomass is not categorically a carbon neutral fuel, so its emissions cannot be assumed to be zero. Stack emissions of CO_2 from burning forest-derived biomass are typically comparable to, or greater than, coal per unit of energy produced (due to the inefficiency of biomass combustion), even according to industry analyses. The assertion that biomass is a carbon neutral source of energy has been falsely promoted by the Trump administration and more generally by industry interests. These assertions have been widely rejected in the scientific peer-reviewed literature, which has shown that most forms of forest-derived biomass increase CO_2 emissions in the atmosphere for many decades to centuries. In particular,	Based on public comment and internal staff review, DEQ originally proposed what was intended to be clarifying applicability language (adding "generated as a result of combusting fossil fuel") to the board at the October 2018 meeting. At this meeting, a board member asked staff why the additional fossil fuel terminology was added, to which staff responded that it was intended to clarify the regulation's applicability given that EO 57, ED 11, and the Attorney General opinion were all directed specifically toward fossil fuel. Staff also pointed out that the issue of how to address biomass is so complex that it could not be addressed in this particular regulatory action. The board member suggested that the issue had been addressed in the definition of "fossil fuel-fired," and that the additional language was unnecessary, confusing, and redundant. Staff and the board agreed that it could be considered during the new comment period on the re-proposal, and the board agreed. At no time did any board member suggest that the purpose of removing the additional language was intended to ensure that the regulation applied to facilities firing or co-firing a certain amount of biomass. While the board did approve the removal of the fossil fuel specification for the purposes of the re-proposal and public comment, and the re-proposed regulation was modified accordingly, the accompanying Agency Background Document was not concurrently modified, and discussion of the clarifying language originally recommended by staff remained in error. Those provisions of the background document (primarily in the

	assumptions about the categorical carbon neutrality of biomass from managed forests have been rejected by the EPA Scientific Advisory Board. If Virginia were to exempt all biomass, including co-firing, from the rule--even if deferring biomass policy formulation until some later time--its action would send a damaging signal that crucial, state-level carbon trading rules can nonetheless embrace the anti-science policies of the Trump administration. We therefore urge DEQ to maintain its coverage of co-fired biomass in the rule as proposed, and in line with the board's binding vote on the matter on October 29, 2018. Biomass co-firing coverage as proposed in the current revised rule is also consistent with DEQ's past actions in this regulatory process. DEQ has consistently asked in past and current comment periods for specific input on how to cover biomass emissions under the rule. Indeed, biomass coverage has always been explicitly contemplated and therefore expected, starting with EO 57 and ED 11. Just as important as maintaining this well-established intent, covering emissions from biomass co-firing is consistent with RGGI policy, with which DEQ rightly seeks to align. The RGGI program requires participants to count emissions from biomass when it is co-fired with fossil fuel (while also providing an exemption from the requirement for eligible feedstocks under prescribed circumstances). To avoid litigation and to align with that larger market, DEQ should unambiguously avoid arbitrary polluter exemptions and retain biomass co-firing coverage in its final rule.	response to comments) have been corrected accordingly in this new background document for the final regulation. Comment was received both in favor of and against the inclusion of the original staff-recommended language emphasizing that the rule is intended only to address the combustion of fossil fuel. Based on comment received during the re-proposal, it appears that removing the fossil fuel provisions has resulted in more confusion than clarification, and thus staff recommends that the clarifying language be restored. DEQ continues to maintain that the scope of this regulation is limited to fossil fuel combustion. DEQ is aware of the concerns associated with biomass, and discussed the pros and cons of including or excluding biomass units with the Regulatory Advisory Panel. The group did not reach consensus on an approach for dealing with biomass; given that, and given the numerous, detailed comments received during the public comment period, DEQ recognizes that this is a polarizing subject. However, the ED 57 Work Group specifically recommended that the Governor consider taking action via a regulatory process to establish a trading-ready carbon emissions reduction program for fossil fuel-fired electric generating facilities. The RGGI Model Rule provides that a biomass-fired facility may be a CO_2 budget source if the use of fossil fuel combusted comprises, or is projected to comprise, more than 50% (commence operation pre-2005) or 5% (commence operation post-2005) of the annual heat input on a Btu basis during any year. Additionally, most RGGI states allow CO_2 budget units that co-fire eligible biomass to deduct CO_2 emissions attributable to the burning of eligible biomass from their compliance obligation in accordance with the RGGI model rule. As of this writing, no RGGI state covers biomass. Finally, regularly scheduled program reviews at both the RGGI and state level

		will provide opportunities to adjust the exemption should implementation issues be identified by Virginia, RGGI, or the general public.
41. NRDC	DEQ should work to ensure the integrity of the program is not eroded by emissions leakage. Leakage is the increase of emissions from power plants outside Virginia to supply in-state load due to a carbon price on in-state generation, beyond business-as-usual import levels absent a Virginia carbon price. DEQ can avoid leakage by (1) designing an economically efficient program with minimal market distortions; (2) ensuring consumer benefits are maximized through efficiency investments; and (3) driving significant levels of in-state, cost-effective renewable energy development. These will all deliver least-cost carbon reductions and mitigate the impact of carbon prices on the flow of carbon-derived power flows across state lines. To verify the program does not inadvertently lead to increased fossil-based electricity imports from out-of-state, DEQ should establish an annual program review process for the duration of the program, to assess whether interstate power flows are shifting as a result of the carbon price. Importantly, a modest price on carbon is but one of many variables that can influence interstate power flows; therefore, any such analysis would also need to account for other potential factors (including changes in fuel prices and potential changes in both load and generation in the interconnection region), in order to draw appropriate attribution conclusions. RGGI has already built in such emissions monitoring and reporting that assesses changes in power flows, and we urge Virginia to do so as well.	As discussed in the initial response to comment 91 and current response to current comment 31, neither DEQ nor RGGI anticipate any leakage issues. Regardless, the program will be closely monitored to assure that this continues to be the case. Note that RGGI monitors for and reports trends in leakage annually. The regulation is based on the RGGI model rule and, as such, includes RGGI's emissions monitoring and reporting requirements.
42. NRDC	Climate change is inherently an environmental justice issue, as coastal communities and low-income communities ultimately bear the worst brunt of its impact. Therefore, the program should make significant cuts to CO_2 and ensure the consumer and energy efficiency benefits flow to the	Support for the proposal is appreciated. Environmental justice is discussed in greater detail in the current response to current comment 33. As noted there, Virginia will be the first RGGI member state to explicitly require environmental justice consideration and review in its RGGI program requirements.

	low-income citizens most impacted by climate change and energy costs. Additionally, because CO_2 is not harmful in locally-higher concentrations, and there do not appear to be specific Virginia plants in proximity to at-risk communities whose capacity factors will increase under a carbon program, a carbon market in Virginia appears unlikely to create hot spots of pollution in frontline communities. And as the cap for carbon emissions is lowered, it can also create additional benefits of further reducing associated co-pollutants that cause health problems in communities close to their source. To ensure this is the case over the course of the program, we support DEQ's inclusion of environmental justice review.	
43. Old Dominion Electric Cooperative (ODEC) and the Virginia, Maryland and Delaware Association of Electric Cooperative	The ICF analysis shows an increase in electricity imports to Virginia by as much as 4 TWh (4 million MWh) on an annual basis or approximately 15% of Virginia's electric usage. Coal units across state lines in non-RGGI states with low utilization are well positioned to ramp up their dispatch to supply these imports, increasing the regional CO_2 emissions by approximately four million tons annually. This would largely cancel the reductions outlined in the re-proposal. As a result, it is likely that CO_2 emissions would be increased by utilization of more carbon-intensive plants in adjacent states. Ultimately this shift from generation within Virginia to generation from just outside Virginia's border will impact Virginia and the region as a whole. The region immediately surrounding and including Virginia may not see an actual decrease in carbon emissions as a result of this regulation. This particular issue of the actual transmission flows requires more study to evaluate what specific generation in adjacent states will be increased and what the overall impact on regional emissions is as a result of the re-proposal. One of the key assumptions made in	See the response to current comment 19 on the topic of electricity imports and the effect of the proposal's allocation approach to encourage in-state generation. As a region, the RGGI states monitor imports and the potential for emissions leakage on an annual basis. Like the other states, Virginia intends to participate in periodic program reviews to assess the effectiveness of the program. To date, those reviews have not concluded that imports or emissions leakage are a problem for RGGI. Should that conclusion change, measures to address emissions leakage could be considered. The commenters' acknowledgment that the value of allowances will indeed be returned to commenters customers is appreciated. With respect to the statements about investor-owned utilities, note that the SCC is charged with protecting utility customers and in carrying out its statutory duties are meant to ensure that utilities return the value of allowances to utility customers. With respect to the energy efficiency inputs to the model, DEQ consulted with Dominion to understand the current savings achieved per dollar spent and

	the economic analysis is that all revenues from the allowance consignment auctions are returned to ratepayers, thus reducing the projected impact on ratepayers. This assumption is stated in the presentation on customer bill analysis. This assumption is inconsistent with the re-proposal. The rule states that the proceeds from the consignment auctions are returned mostly to affected generators with a small carve out for DMME. While ODEC, as a member-owned cooperative, will return its revenues from the consignment auction to its member-ratepayers by virtue of its business and organizational model, some of the affected generation in the state is owned by independent power producers who will keep all proceeds from the consignment auction. Even the regulated, investor-owned utilities may decide not to return all auction revenues to ratepayers, nor can the rule require this. Further, if legislation granting the state permission to administer the funds instead of returning it to generators is promulgated, then none of the consignment auction revenues will be necessarily automatically returned to ratepayers. The ICF analysis assumed a flat load forecast as a result of GSTA, which includes "significant energy efficiency investments by regulated utilities (close to $1 billion)." The documentation of how much energy efficiency can actually be achieved with this investment has not been studied by ICF, and, was rather, estimated using data that was not appropriate for large scale applications. By forecasting no load growth, the ICF analysis makes compliance seem easy and cheap, because emissions levels, plant generation needs, CO_2 prices, and firm power prices are all lower when loads are assumed to be low. The ICF results are only valid for a scenario with this load assumption. Future compliance costs are understated if	determined the modeling inputs with the information in hand. With respect to offshore wind, the modeling did not assume new offshore wind for Virginia other than the small demonstration project that is indeed expected to be completed and operational.

	Virginia's economic expansion and data center expansion outpaces the likely-overstated energy efficiency reductions achieved by the GTSA spending. The recent announcement of Amazon's choice of Virginia for its HQ2 location is key evidence that low- to no-load growth is not necessarily going to occur. Virginia, in fact-and especially Northern Virginia-continues to be a high-growth area. The ICF analysis assumes that several off-shore wind projects will come to fruition. The off-shore resources are being used in the study to meet incremental demand. These projects are being opposed, and may not actually occur. While an assumption like this may seem trivial, if these projects are not constructed the expected generation need to replace these projects would equate to roughly 14% of the overall RGGI allowance cap which would have a significant impact on RGGI allowance prices and ultimately the cost of compliance for Virginia utilities. These issues related to the modeling of the potential impacts highlight the complex nature of the proposal and the need to take more time to assess the real impacts of linking to RGGI. We urge that the implementation of the regulation be postponed until a more thorough evaluation can be performed.	
44. ODEC	We have significant concerns regarding the anticipated impact of this regulation on the electric bills of its ultimate consumers. In the service territories served by ODEC and Association, many rural consumers are having trouble paying their bills. Even a modest increase in bills will be problematic, and larger increases in costs will turn electricity into a luxury item. The Cooperatives have only their ratepayers from which to recover costs; there are no separate stockholders. This fact makes the implementation of this rule all that much more troubling for the Cooperatives. This program has the	The bill impacts of the proposal are expected to be very small. Historically, RGGI allowance prices have been lower than projected in the IPM modeling and if this historical trend continues, we can expect the bill impacts to be very low. In addition, if the allowance prices happen to be higher than expected, the proposal includes a Cost Containment Reserve that will essentially relax the emissions cap to lower allowance prices. The commenter refers to the letters filed with state legislators by the SCC staff, which in turn relies on a modeling analysis conducted by Dominion. DEQ was not consulted on this analysis nor

	potential to produce a multitude of unintended consequences, each of which could, individually, have sizable cost implications. The Cooperatives are particularly concerned about protection of our consumers. We reference the letter to Delegate Kilgore from SCC staff citing results of their modeling of bill impacts due to the implementation of the re-proposed rule and the SCC letter to Delegate Poindexter which followed it. Based upon their analysis, impacts on average for Dominion customers was an average monthly bill increase of $7 to $ 1 2. The SCC used Dominion's PLEXOS model, but a number of the assumptions which they listed were similar, if not identical to assumptions made in the ICF modeling runs that were used in the impact projections presented by Analysis Group in support of the re-proposal. These include: using the price floor for carbon emissions published by RGGI; using a discount rate of 6.31%; modeling DOM zone costs recognizing that that customers pay whether a unit runs or not; assuming that the 5,000 MW of solar, 30 MW of battery storage and $870 million of spending on energy efficiency programs, all of which is mandated under the GTSA, came to fruition; and using the 28 million tons with a 3% reduction through 2030 consistent with the re-proposal. SCC's concerns should have been addressed by DEQ working closely with the SCC. DEQ's rule will obligate Virginia to reductions that RGGI desires while not properly addressing the utility regulatory aspects that is one of the foundations of the RGGI organization. The RGGI Board is comprised of two representatives from each state, one from the utility regulatory area and the other from the environmental agency. These two representatives conceptually work in concert to establish balanced reductions for their own participating state with minimal impacts to consumers. It is quite obvious that	given an opportunity to comment on the assumptions used or methodology employed. The commenter is incorrect that the Dominion modeling uses the same assumptions as that used in the IPM analysis. The Dominion modeling and SCC assessment were conducted in private and the assumptions and methodology are not yet known. Nevertheless, from what has been disclosed there appear to be a large number of defects in Dominion’s modeling approach and in the SCC’s reliance on that analysis. See the current response to current comment 20. Also note that in addition to issues identified in current response to current comment 20, the SCC statements and the related Dominion modeling do not relate to commenter, commenter's service area, or commenter's customers.

	there is not alignment among the state agencies regarding the potential impacts to consumers from this re-proposal. Considering this fact alone, DEQ is encouraged to delay implementation and take the time to form a multi-year regulatory working group that closely integrates environmental and utility regulators, and outside experts from across stakeholder groups, to more fully vet the re-proposal before it is enacted. Finally, under the regulation, there is no established legal requirement to return revenues to ratepayers. These numbers greatly concern us. The impacts to the Cooperatives' member-consumers could be significantly different from what the SCC has projected for Dominion customers, and the SCC letter to Delegate Poindexter indicates that they have not even begun the process of modeling those impacts. While Dominion supplies the majority of electric consumers in Virginia (5 million customers), our Virginia Cooperatives served by ODEC equate to approximately 1.1 million consumers. There are fewer ratepayers over which to spread any cost increases. Based upon the difference in Dominion as an investor-owned utility versus the Cooperatives as not-for-profit member-owned utilities, there could a much wider range of financial impacts that have yet to be fully vetted. While it has long been accepted in the promulgation of any regulation that there are various models and economic analyses to show the cost impacts of the rule, the simple fact that this pollutant cannot be controlled with specific and defined commercially-available control equipment, as is the case with other criteria and hazardous air pollutants, makes the rule problematic. There is no environmental modeling that can be run to show any projected local benefits based on the anticipated program reductions.	
45. ODEC	As we have commented previously, regulating CO_2 at the state level is not	A regional approach is indeed better than a single state approach. The proposal is

	as effective as a broader, integrated regional or national approach, particularly when the regulation of CO_2 is in a state that is surrounded by states that are not regulating CO_2. There are numerous unintended consequences that may arise from such a market distortion. By putting this additional financial burden on Virginia generation, the effect will be encouraging imports of electricity from other states, potentially requiring the construction of additional transmission infrastructure to maintain reliability. DEQ's modeling clearly shows these effects with projections of 16% of electricity needs coming from imports in 2020 and rising to 25% by 2030. If the proposal is to move forward, we recommend adding a provision for an analysis of trends in imports in Virginia once the program has been implemented. If there is indeed a significant increase in imports, Virginia should have the ability to make programmatic adjustments to scale back the regulatory requirements for in-state generators to deter the import of out-of-state generation. The board should consider any number of safety valve measures-for consumer protection from price increases, for reliability of the electricity system, and for imports from out-of-state. The additional burden of this program could result in premature retirement of coal facilities or significantly reduced utilization of existing coal resources. These Virginia power generation resources were designed, built, and permitted in strict compliance with federal and state regulations to meet the long-term electricity needs for ratepayers. Implementation of this rule may reduce the remaining useful life of these assets which are still being paid for by all consumers, and certainly are still being paid for by the ODEC Member Systems' member consumers. At the very least, Virginia needs to develop a mechanism to compensate consumer-funded, prematurely-retiring coal generation.	designed to make Virginia a part of a regional emissions trading market to provide generators with maximum flexibility and to make sure reductions are cost effective. The analyses conducted suggest that the cost impacts of the program will be minimal. As discussed in the initial response to comment 91 and current response to current comment 19, neither DEQ nor RGGI anticipate leakage issues. Nevertheless, the program will be closely monitored to assure that this continues to be the case.

	One possible mechanism would be to carve-out allocations for retired consumer-funded generation for a significant number of years after their retirement. This type of solution would also remove a barrier to the closure of consumer-funded coal generation, by providing allocated allowance revenue to offset the stranded costs paid for by consumers. Other mechanisms could also be considered, and make more sense, but those would likely require legislation to implement. Those renewable generation resources owned directly by Cooperatives should continue to be counted as renewable resources and excluded from the Regulation. This includes not only solar PV projects, of course, but also the carbon-neutral wood waste biomass plant in Halifax County serving member-consumers of Northern Virginia Electric Cooperative. Beyond increasing imports using current transmission infrastructure, recent changes in PJM's market efficiency process will promote construction of new transmission from outside Virginia into the Dominion zone. State participation in RGGI coupled with PJM's market efficiency process set the stage for economically encouraging increased use of existing coal facilities and construction of new gas facilities just outside Virginia's border to incrementally meet Virginia's energy needs in the future. As noted above, this could very well result in no net reduction in regional CO_2 emissions despite the increased cost to Virginia rate payers. The issue of leakage is a very complex issue for which states continue to grapple. Virginia, as part of the PJM RTO, may very well have to grapple with this issue, and spend significant resources in the future to control leakage. Leakage is not just a theoretical modeling concern, but is a real problem that is already happening in existing RGGI states. The second fact is that despite RGGI's requirements to consider	

	leakage and to make adjustments to address it, RGGI clearly has not done so and cannot be relied up on to correct the problem for Virginia. The proposal should include Virginia-specific rules to reduce or eliminate leakage.	
46. ODEC	Virginia has seen an overall downward trend in carbon intensity of its generation. Virginia already has one of the lowest carbon intensities among the PJM states, which also includes RGGI states that have been involved in the program since its inception. It is not appropriate to reduce the starting budget to 28 million tons given the past trends and the progress that has already been made in the absence of any rule. Current trends support the initial budget higher than 28 million tons. While the trend has been declining over the years, there has been a great deal of investment in new clean combined cycle generation which would be subject to this program. Virginia should be allowed to enter the RGGI program with a budget that is fair to Virginia given the current generation resources. The aspect of the program bank adjustments being applied to Virginia as we are just entering the RGGI market puts a greater burden on Virginia sources than is warranted, as we have outlined in greater detail in the subsequent section. Additionally, as is highlighted within the VMA comments, there are significant concerns regarding the extent of the industrial exemption that is provided in the proposal. DEQ has stated that their assumptions in the modeling are that no industrials would be considered affected units. If that is truly the case, then the language which provides for that exemption should be very clear. Otherwise, the budget would need to be re-evaluated simply to account for any potentially affected industrials.	It is true that both Virginia and the RGGI participating states have seen a downward trend in carbon intensity, which is why a lower budget of 28 million tons is more appropriate than a higher budget. Regarding the basis for the emissions cap in the proposal, the IPM analysis projects that emissions from covered sources in Virginia will be 28 million tons of CO_2 in 2020. This projection is based on the best modeling inputs available, including inputs relating to expected energy efficiency and renewables investments in Virginia and elsewhere in the EI. This approach is consistent with best modeling practices. Thus, the 2020 Virginia emissions cap is set at the expected emissions level in 2020 and does not disadvantage Virginia entities. Note that the RGGI states conduct periodic program reviews to assess the program. These reviews may result in changes in the emissions caps (either up or down) based on conditions observed in the region.
47. ODEC	ODEC understands that there is a strong desire by the Administration to start participation in RGGI, and that negotiations have been centered around Virginia entering in 2020.	RGGI allowance auctions are already open to participation by Virginia entities, meaning Virginia entities can acquire emissions allowances that can be used for compliance even though Virginia

	However, beginning in 2020, the last year of a 3-year control period, puts additional strain on generators for procurement of allowances. Virginia generators will not have any time to determine changes in the overall market. Normally, generators would have 3 years to be able to optimize their allowance procurement strategy before the final true-up. In Virginia, all the generators will have only one year to ensure they procure enough allowances to cover the emissions for that initial participation year. To alleviate this burden, assuming the regulation goes forward, we propose that the start of implementation of the program not commence until January 1, 2021, which is the start of the next control period. Additionally, given that the Virginia generators would be just now entering the RGGI-linked program, the banking adjustments that have been calculated by RGGI and are being proposed to be applied to subsequent years, should not be applied to the Virginia budget. These banking adjustments are based on participants outside of Virginia banking more allowances than anticipated, and not the actions of any generators in Virginia. Such an adjustment should only be applied to existing RGGI participants. Alternatively, if Virginia does not wish to diverge from the bank adjustment process, as we have indicated in the previous section, the initial budget of 28 million tons should be increased to the originally-proposed amounts of either 33 or 34 million tons. This would ensure that applying the banking adjustments will not put unwarranted burden on Virginia's sources. As we stated in previous filings, we feel that there should be consideration given to reliability and resiliency safety valves. Such mechanisms would recognize that over-reliance on intermittent generation or a single fuel such as natural gas which is not easily storable, may negatively impact reliability and resilience. Analyses should be performed to assure that	entities do not currently have a compliance obligation and will only have one year's emissions to cover with allowances in 2021. Also note that there is currently a very large private allowance bank across existing entities covered by RGGI, which means there is currently a general oversupply of allowances in the RGGI market. Indeed, this is the reason for the bank adjustment that will take place in the early 2020s in the RGGI program. In short, Virginia entities are already well positioned to plan for compliance for the single year of 2020. The bank adjustment was part of the IPM analysis of the proposal and that analysis informed the decisions on starting cap level and rate of cap decline. The proposal as a whole, including the bank adjustment, is expected to have minimal cost impacts as stated in the analyses released in connection with the proposal. Thus, the bank adjustment does not necessitate an adjustment to the starting cap level.

	resiliency is maintained and that critical generation resources are not retired because of the impacts of this regulation. In the case where retirement of critical resources is likely, adjustments to the allowance allocations should be contemplated.	
48. ODEC	We generally support the provision establishing that 95% of the budget will be allocated to the generators. Particularly for the Cooperatives, revenues from the consigned allocations will subsequently go back directly to our member-consumers. This is a critical means to reduce the net cost impact on electric consumers. Setting a price on CO_2 emissions as this program does, is enough incentive for all sectors to seek ways to reduce emissions. Even when allocated allowances, utilities will still be incented to pursue low- or non-emitting resources and energy efficiency measures. Not having allowances granted to such sources and forcing electric ratepayers to foot the bill for CO_2 emissions will invariably be a significant cost impact and can be at least somewhat mitigated by allocated allowances to generators as proposed. As stated previously, any utility with a wholesale power contract could be adversely affected by the implementation of a system where their consumers end up paying for the costs of CO_2 emissions and receive nothing in return. This could be resolved by flowing auction revenues through applicable FERC ratemaking mechanisms using FERC Form 1 data. However, this difference, and the complexity of DEQ involving itself in a mechanism of wholesale ratemaking, should merely serve to reiterate our concerns. We further recommend allocation based on emissions, not megawatts generated. Incumbent utilities have made significant investments under the existing regulatory compact to provide power economically and reliably to meet retail loads. Because of these significant investments, there should be an appreciation for the value associated with these investments in	Support for the allocation approach in the proposal is appreciated. The topic of how to allocate allowances under the RGGI program has been discussed at great length during the stakeholder process and through regulatory development process. The output updating method was ultimately selected due to its ability to promote cleaner more efficient power generation, and to react to changes in the Virginia power sector in the future. To the extent that the allowances go back to the generators, it will serve to reduce the impact of participating in the RGGI program on wholesale prices. Everyone bids into the market, so everyone gets the value of the clearing price. The commenter is correct that the allocation of allowances should result in the flow of the allowance value to customers. In the case of long-term power purchase agreements with merchant facilities, the allocation of allowance value is a matter for the parties to those contracts to address. Indeed, the potential for this type of program has been present for several decades, suggesting that parties to any existing agreement had ample reason to account for the value of allowances awarded to merchant power under contract to a utility or other load-serving entity. As such, the allocation method in the proposal should protect consumers by ensuring that the value of allowances awarded to covered entities flow to the customers that have to pay for allowances in their power bills. See also the response to current comment 43.

	electric generating plants. The conditional allocations being allocated on an emissions basis will serve to provide a "glide path" for the existing resources to continue to operate within their remaining useful life, rather than having significant stranded resources which will directly impact our consumers and what they pay for electricity. Coal generators would still be incented to operate as efficiently as they can since the allowance price will set the cost of each ton of CO_2 emitted irrespective of who is given the allowances.	
49. ODEC	RGGI is a consensus organization, and the RGGI Model Rule already provides a structure for participating states to make adjustments and plan for the future. No one can know what the state of the electric utility industry will be in 2030. ODEC strongly disagrees with the provision proposed in 9VAC5-140-6190 C, which obligates Virginia, in the absence of any adjustment, to an arbitrary reduction value for 2031-2040. Requiring an 840,000 ton per year reduction as a hard-and-fast amount is both inconsistent with the intent of ED-11 and the reasonable standard for program review already established by RGGI If Virginia is participating in RGGI because it is a well-established multi-state trading program, why should the board feel the need to diverge from the Model Rule? Additionally, based upon the latest comments submitted by RGGI, RGGI states had some consternation with Virginia diverging from the Model Rule. The last sentence of this section is arbitrary, adds no real value to the program, and should be removed.	As discussed in the current response to current comment 54, DEQ agrees that participation in the RGGI program means following the RGGI protocols developed on a consensus basis with the participating states.
50. Delegate Israel O'Quinn, 5th District	I'm formally registering my opposition to the RGGI rule making process. There is a great deal of disagreement over the policy decision of joining RGGI, and while I am in fact opposed, there is a larger and more pressing issue at stake. The Administration had HB 1273 filed during the 2018 session, and the bill's summary stated in part, "…The regulations are required to comply with the Regional	Delegate O'Quinn's concerns are recognized. As discussed in the initial response to initial comments 76, 139 and 159, and in the current response to current comment 29, it is necessary and appropriate for the board to promulgate state-specific regulations controlling carbon pollution. The board's legal authority to issue regulations controlling air pollution is found in the Code of Virginia at §§ 10.1-1306 through 10.1-

	Greenhouse Gas Initiative model rule…" The bill came before the Commerce and Labor Subcommittee that I chair and during debate on this bill I directly asked Secretary Strickler if this bill was defeated, would the Administration proceed with joining RGGI regardless. His answer was, "yes." After debate on the bill, HB 1273 was defeated 6-4 in the subcommittee. Meanwhile, the General Assembly passed HB 1270, which was a bill explicitly prohibiting the Governor from joining RGGI. That bill was subsequently vetoed by the Governor. During the 2019 session, the Administration made another run at RGGI via HB 2735. That bill summary also stated in part, "…The regulations are required to comply with the Regional Greenhouse Gas Initiative program…" HB 2735 came before the same subcommittee and, after debate, was defeated by a vote of 6-3. In similar fashion to 2018, the General Assembly once again passed a bill (HB 2611) explicitly prohibiting the Governor from joining RGGI. It is clear that the Administration believes they need General Assembly approval to legitimately move forward with RGGI or they would not have had bills filed in successive sessions requesting such authority. But it is also clear that absent that consent, they are willing to move forward without the appropriate authority and operate far outside the bounds of--and in direct opposition to--legislative intent. The Administration has no authority to join RGGI or to promulgate regulations on the matter.	1308; the Office of the Attorney General of Virginia issued an official advisory opinion on May 12, 2017, which concluded that the board is legally authorized to regulate carbon pollution under these sections of the code. On March 14, 2019, Governor Northam vetoed House Bill 2611 on the basis that it was not protective of the environment as well as in violation of two provisions of the Virginia Constitution: Article III, Section 1 (Separation of Powers) and Article IV, Section 11 (Enactment of Laws).
51. Partnership for Public Integrity (PFPI)	We represent 6 environmental organizations based in Virginia and elsewhere. We are writing to express our concern that the Northam administration may decide to exempt CO_2 emitted by burning biomass for electricity, typically forest wood, from the state's plan to cap and reduce emissions from power plants. Dominion operates 5 power plants that could be exempted from the plan, four that burn wood exclusively, and VCHEC that burns coal and up to	As discussed in the current response to current comments 24 and 40, DEQ continues to maintain that the scope of this regulation is limited to fossil fuel combustion. DEQ fully appreciates the concerns associated with biomass. However, the purpose of this particular regulatory action is to establish a trading-ready carbon emissions reduction program for fossil fuel-fired electric generating facilities consistent with the RGGI program, and the re-proposed regulation accomplishes this.

	20% biomass. Allowing CO_2 emissions from biomass combustion to go unregulated–when in fact, wood-burning power plants emit more CO_2 per megawatt-hour than even coal plants–rewards cutting and burning forests for energy, when restoring and expanding forests is actually essential in the fight to reduce GHG. Virginia should show leadership by accurately counting CO_2 emissions from burning biomass. In previous comments, several environmental organizations provided 2 ways to accomplish this goal: directly count biomass-related CO_2 emissions from power plants, or use a net emissions methodology that calculates emissions assuming some CO_2 is offset. We urge you to adopt one of these approaches. According to the IPCC, reducing GHG emissions by 45% from 2010 levels by 2030 is critical in order to keep global temperature increase from exceeding 1.5°C above pre-industrial levels. Virginia's plan to reduce CO_2 emissions by 30% between 2020-2030 is an important step forward in reducing GHG emissions. However, the plan should not at the same time incentivize cutting and burning forests for energy. The IPCC is clear that avoiding dangerous climate change requires not just reducing emissions, but increasing carbon uptake. Forest growth represents the only significant terrestrial sink for carbon dioxide emissions, and reducing the forest sink by harvesting forests for energy increases atmospheric CO_2 by reducing carbon storage and sequestration. At its meeting in October, the board rightly removed the unexpected express exemption of biomass emissions from plants that co-fire biomass with coal. The body of the revised proposal appears to reflect that change by correctly renewing coverage of co-firing plants. However, it remains unclear whether the agency intends to cover co-fired biomass emissions because the summary of the revised proposed rule	Note that none of the current RGGI states covers biomass units, making the proposal consistent with the current RGGI program.

	states that "other substantive changes in the re-proposed action include…exemption of fossil fuel units that co-fire with biomass from CO_2 accounting." The Governor and DEQ would be on solid scientific and policy ground in clearly covering woody biomass emissions. Arguments that biomass CO_2 emissions should not be counted or that biomass should be treated as carbon neutral are often based on the claim that if forestry residues are used as fuel or pellet feedstock, emissions from combustion are no greater than the emissions from letting the material decompose, rendering the material effectively carbon neutral. However, even under such best-case scenarios, current science shows burning biomass has significant net emissions that persist for decades. In 2015, U.S. Representatives Don Beyer and Gerald Connolly criticized a proposed EPA policy that would have counted biomass waste products or "sustainably harvested" biomass as emitting zero carbon dioxide under CPP. Like Virginia's proposed plan, the CPP was intended to reduce CO_2 emissions from power plants. Rep. Beyer said he shared the concern of Virginia-based environmental groups that if biomass were exempted from regulation under the CPP, "Virginia will become known as a state that harvests forests to reduce its dependence on coal, rather than one that develops renewable technologies that clearly reduce emissions, such as solar and wind." Rep. Connolly wrote that "the decision to treat biomass as carbon-neutral may have unintended consequences that could actually undermine and inhibit our ability to reduce carbon emissions." Rep. Beyer cited a 2015 Washington Post story about how the European Union's treatment of bioenergy as carbon neutral has driven forest clear-cutting in the U.S. southeast to manufacture wood pellets that replace coal in the E.U. Multiple scientists also weighed in on	

	the importance of counting bioenergy emissions. Virginia has indicated that it needs to treat biomass as carbon neutral to be consistent with RGGI. But that is a factually incorrect understanding of what RGGI does. The 9-state program in fact requires participants to count emissions from biomass when it is co-fired with a minimum amount of fossil fuel, providing an exemption for emissions from sustainably harvested biomass. Virginia can improve on the RGGI policy and show truly robust climate leadership by counting all CO_2 emissions from biomass at commercial plants of 25 MW and above, and not granting exemptions that allow biomass to be treated as zero emissions. We urge the accurate count of CO_2 emissions from biomass from commercial electric facilities of 25 MW and greater.	
52. A.G. Randol III, VA Scientists and Engineers for Energy and Environment; Charles Poindexter	The re-proposal is even more draconian than the initial proposal. The re-proposal extends the emissions cap 10 more years to 2040 and lowers the initial cap from 34 million tons CO_2 in 2020 to 28 million metric tons without any valid justification. DEQ must withdraw the proposal for the following reasons. 1. The bills that require General Assembly approval of any proposal to limit emissions from power plants or transportation were passed, including HB 2269 and HB 2611. The bills that attempted to provide a legal framework for RGGI were defeated, including HB 2735 and SB 1666. The introduction of this legislation confirms that there is no legal basis for this regulatory overreach. All of the bills that proposed a moratorium on fossil fuels were defeated. Further more, the board has not met the requirements of § 10.1-1308 of the Code of Virginia. CO_2 is not an air pollutant, it is a fertilizer for plants. Pollutants from power plants are controlled by federal law under the NAAQS. RGGI is more restrictive than applicable federal requirements and conflicts with the federal ACE rule.	1. See the initial response to initial 76. 2. See the current response to current comment 20 for a discussion of the SCC analysis. 3. See the initial response to initial comment 61.

	2. SCC staff has critiqued the DEQ analysis as follows. RGGI has not published any prices beyond 2030 even though the re-proposal requires reductions through 2040. Virginia is a net purchaser of electricity from PJM and the RGGI scheme will increase our dependence on PJM. Net purchases from PJM in 2020 are projected to be 7M MWh (8.2%) growing to 19.7M MWh (21.4%) in 2040. PJM will require additional generation not less. DEQ's claim that consumer bills will fall is incorrect. DEQ modeled Virginia as a deregulated market, which it is not. DEQ does not capture the costs of premature plant retirements ($780 million) or the cost of replacement capacity ($1.3 billion plus financing costs and profit margin). DEQ relied on models and assumptions not suited for analysis of the proposed regulation. The PLEXOS model is an integrated energy model that simulates the Virginia power market and is used by the SCC. This is the model that should have been used. DEQ omitted the customer bill impact of increased fuel costs, prematurely retiring generating units and the additional costs for fossil fuel units that continue to operate. DEQ used a discount rate 3x lower than the standard used by the SCC (weighted average cost of capital) which results in understating the true costs of future capital investments. RGGI penalties will lead to higher PJM energy prices imposing costs across the entire PJM grid. Other states in PJM may have a cause of action against Virginia to demand compensation for these arbitrarily imposed billions in costs. DEQ does not account for the businesses and industries that are forced to leave the state because of higher electricity prices. 3. Electricity rates in RGGI states are well above the rates in Virginia. Driving rates higher under RGGI will penalize Virginia consumers for no demonstrable benefit. The residential	

	electricity rates in Virginia are lower than the rates in every RGGI state.	
53. RGGI	The RGGI states continue to applaud Virginia's important steps toward implementing a market-based program to reduce GHG emissions, and note that the re-proposed rule addresses many of the points on which the RGGI states commented when Virginia proposed the original version of the rule. In particular, the RGGI states recognize that this revised rule contains a reduced starting CO_2 allowance budget; a change in line with the RGGI states' earlier comments that opportunities existed to make the rule more ambitious. The RGGI states find that a 2020 starting budget at or below the proposed 28 million short tons demonstrates comparable stringency with the existing program. As previously emphasized, the participating states recognize the many benefits of an expanded trading market, including increased economic efficiency and mitigation of the possibility of emissions leakage. Participation in RGGI has helped the participating states create jobs, save money for consumers, and improve public health, while reducing power sector emissions and transitioning to a cleaner energy system. If implemented successfully, expanded RGGI participation will serve to amplify these benefits.	Support for the proposal is appreciated.
54. RGGI	Aside from the starting budget, other aspects of program design remain important in ensuring that any new entrant's participation in the RGGI market is fully compatible with our existing program. The RGGI states require that each participating state promulgate a CO_2 budget trading program regulation that is consistent with the RGGI 2017 Model Rule. In the re-proposal, the language specifying Virginia's base budget reductions between 2030 and 2040 is inconsistent with the RGGI 2017 Model Rule. Accordingly, the RGGI states strongly urge Virginia to adopt a consistent budget trajectory to the	The proposal has been revised accordingly. DEQ agrees that participation in the RGGI program means following the RGGI protocols, which are developed on a consensus basis with the participating states. In addition, DEQ is required by state law to review its regulations every 4 years. These requirements taken together will ensure that no premature conclusions are drawn as to what the cap ought to be in 20 years' time.

	other participating states. In the event that Virginia, or any participating state, wishes to effect changes in the region's long-term cap trajectory, the appropriate vehicle is the periodic RGGI program review process. Through this process, the participating states consider an appropriate trajectory for continued emissions reduction and arrive at a consensus decision supported by discussion, analysis, and stakeholder engagement. In previous program reviews, the states have twice reached consensus on plans to secure additional long-term emissions reductions. We have committed to commencing the next program review by 2021.	
55. RGGI	Modify the definition of "conditional allowance" by correcting "sources" to "source," and by striking the last sentence which is redundant (there is already exists a separate definition for "conditional CCR allowance").	The proposal has been revised accordingly.
56. RGGI	Use consistent terminology to refer to conditional allowances. See, for example, the proposed definition of "allocate." "CO_2" should be removed from "CO_2 conditional allowances" in order to match the regulation's definition of "conditional allowance." This error also appears in 6020 C "allocation year," 6215 B.1, B.2, B.3; 6220 A; and 6250 A.1.	The proposal has been revised accordingly.
57. RGGI	Use the term "conditional allowances" where applicable. See, for example, the proposed definition of "allowance auction." The RGGI states suggest that in this usage, the term "CO_2 allowances" should be replaced with "conditional allowances." According to the definitions in the proposal, the allowances would become CO_2 allowances only after they have been sold. This error also appears in the definitions of "CO_2 emission containment reserve allowance," "CO_2 emission containment reserve trigger price," "reserve price," "undistributed CO_2 [sic] allowances," "unsold CO_2 [sic] allowances," "Virginia CO_2 Budget Trading Program adjusted budget," and "Virginia CO_2 Budget Trading Program base budget," and in	The proposal has been revised accordingly.

	6210 H, H.3; 6211 heading; 6215 heading, A; 6250 heading, B, C; and 6420 A.1, A.5, B.1.	
58. RGGI	At 6190 B, the phrase "an allowance to be used for compliance purposes" should be replaced with "a CO_2 allowance once it is sold to an auction participant" in order to match the definition of a conditional allowance.	The proposal has been revised accordingly.
59. RGGI	The definition of a "CO_2 CCR allowance" should be revised per the following in order to reflect the fact that conditional CCR allowances become CO_2 cost containment reserve allowances after being sold at auction: "CO_2 cost containment reserve allowance" means an allowance that has been sold at an auction for the purpose of containing the cost of CO_2 allowances. CO_2 CCR allowances are subject to all applicable limitations contained in this part."	The proposal has been revised accordingly.
60. RGGI	Revise the definition of "conditional CCR allowance" as follows: "Conditional CCR allowance" means an allowance that may be offered for sale when the CCR is triggered. If any conditional CCR allowances are unsold, they may be offered for sale in future auctions during the same year. Conditional CCR allowances offered for sale at an auction are separate from and additional to conditional allowances allocated from the Virginia CO_2 Budget Trading Program base and adjusted budgets. Conditional CCR allowances are subject to all applicable limitations contained in this part."	The proposal has been revised accordingly.
61. RGGI	The term "CO_2 CCR allowance" should be replaced with "conditional CCR allowance" per the revised definition. This error also appears in the definitions of "Virginia CO_2 Budget Trading Program adjusted budget," and "Virginia CO_2 Budget Trading Program base budget," and in 6210 B, C, C.1, C.2, C.3; and 6410 A.1, A.2, B, B.1, B.2, B.3, B.4, B.5.	The proposal has been revised accordingly.
62. RGGI	Revise the definition of "allocate" or "allocation" per the following to avoid using the word "allocate" within the definition: "Allocate" or "allocation" means the determination by the	The proposal has been revised accordingly.

	department of the number of conditional allowances recorded in the conditional allowance account of a CO_2 budget unit or the Department of Mines, Minerals and Energy (DMME) pursuant to…."	
63. RGGI	Sections 6230 A and 6250 A.1 refer to a "conditional allowance account," but there is no corresponding definition in section 6020 C. The RGGI states recommend defining the "conditional allowance account" as a general COATS account established by the department for CO_2 budget sources and DMME or its contractor where conditional allowances allocated to CO_2 budget sources and DMME are held until auction.	The proposal has been revised accordingly.
64. RGGI	Because DMME would not need a compliance account, revise 6230 A to refer to a "conditional allowance account" as follows: "Upon receipt of a complete account certificate of representation…the department or its agent will establish a conditional allowance account and a compliance account for each CO_2 budget source for which an account certificate of representation was submitted, and a conditional allowance account for DMME."	The proposal has been revised accordingly.
65. RGGI	Amend the definition of "conditional CCR allowance" to remove reference to a "CCR account": "Conditional CCR allowance" means an allowance that may be offered for sale when the CCR is triggered. If any conditional CCR allowances are unsold, they may be offered for sale in future auctions during the same year."	The proposal has been revised accordingly.
66. RGGI	6210 A and C refer to "the Virginia Consignment Auction Account" and "the Virginia Auction Account," although neither term is defined. If there will be a single auction account for Virginia consignors, the term "Virginia Consignment Auction Account" should be defined. The rule should also stipulate the following. Conditional allowances and conditional CCR allowances allocated for a calendar year will be automatically transferred to the Virginia Consignment Auction Account to be consigned to auction.	The term "Virginia Consignment Auction Account" has been selected and the proposal has otherwise been modified appropriately.

	Following each auction, all conditional allowances sold at the auction will be transferred from the Virginia Consignment Auction Account to winning bidders' accounts as CO_2 allowances. Conditional CCR allowances sold at auction will be transferred to winning bidders' accounts as CO_2 CCR allowances. Unsold conditional CCR allowances will remain in the Virginia Consignment Auction Account to be re-offered for sale at auction within the same calendar year. Conditional CCR allowances remaining unsold at the end of the calendar year in which they were originated will be made unavailable for sale at future auctions.	
67. RGGI	The definition of "adjustment for banked allowances" should be replaced by the text below. The term "control period" should be replaced by "initial control period" to match the definition of the period from January 1, 2020 to December 31, 2020. The March 17, 2021 date should also be changed to March 15, 2021, in order to match the RGGI Model Rule. The "March 17, 2021" error also appears in 6210 E. "Adjustment for banked allowances" means an adjustment applied to the Virginia CO_2 Budget Trading Program base budget for allocation years 2021 through 2025 to address allowances held in general and compliance accounts…that are in addition to the aggregate quantity of emissions from all CO_2 budget sources in all of the participating states at the end of the initial control period in 2020 and as reflected in the CO_2 Allowance Tracking System on March 15, 2021.	The proposal has been revised accordingly.
68. RGGI	The defined term "initial control period" should be included when referencing requirements for a control period. This applies to the definitions of "CO_2 allowance deduction," "CO_2 allowance transfer deadline," "CO_2 budget emissions limitation," "compliance account," "excess emissions" and "ton," and 6050 C and	The proposal has been revised accordingly with some minor modifications.

	D; 6170 A; 6200 A, B; 6260 A, A.1, A.2, A.3, B, B.1, C.1, C.2, D. The RGGI states also recommend including new subsections to address initial control period in 6050 C and 6260 D.	
69. RGGI	At 6020 C, the RGGI states recommend that the control period from 2021 through 2023 be referred to as the "fifth control period" in order to align with the term used in the existing program. It can be clarified that the fifth control period is the first control period in which Virginia will participate. In addition, the interim control period start date should say "2021." "Control period" means a three-calendar-year time period. The fifth control period is from January 1, 2021 to December 31, 2023, inclusive, which is the first control period of Virginia's participation in the CO2 Budget Trading Program. The first two calendar years of each control period are each defined as an interim control period, beginning on January 1, 2021.	The proposal has been revised accordingly.
70. William Shobe, University of Virginia	I will not discuss the change in the treatment of industrial sources except to say that it is consistent with the structure of RGGI, exempting industrial generators that generate electricity primarily for internal use rather than for sale to the grid. Such exemptions are common in cap and trade programs to prevent leakage of emissions in trade-exposed industries. The changes proposed by DEQ are appropriate. DEQ made a number of corrections to its original assumptions used in its IPM modeling for the rule. The corrected assumptions included a renewables build-out more consistent with current practice and policy, a more realistic growth rate in electricity demand, and lower natural gas prices. As a result of the more realistic modeling assumptions, the IPM results show a much lower cost of achieving emission reductions. The baseline policy run shows Virginia	Support for the proposal is appreciated. As discussed in the current response to current comment 54, Virginia agrees that the establishment of reduction beyond 2030 must occur under RGGI's consensus process.

	business-as-usual emissions remaining steady at 29 million tons per year. The baseline 9-state RGGI market is quite slack, with allowance prices at or near the auction reserve price, and the full 10% retirement through the ECR mechanism. In fact, several million tons of allowances remain unsold at the reserve price and are retired. The model runs with Virginia joining at the lower cap of 28 million tons in 2020 still show some relative slack in the RGGI market. The full 10% of allowances in the ECR are retired, although no allowances are retired due to a failure to meet the auction reserve price. The prices of allowances are somewhat higher in the lower cap scenarios, but still quite modest at under $5 per ton of CO_2 (in 2017 dollars). This is about a tenth of the social cost of carbon measure developed to guide current decisions about investment in CO_2 emission reductions. It is important to note that the new, lower cap is not binding on Virginia for cumulative emissions during 2020-2030. The new annual cap levels will not be binding on Virginia emissions until around 2028, at which time, firms will have accumulated a large bank of allowances, which will not be fully depleted by 2030. This does not mean that there is no cost to current emission reductions, only that they are very modest because the cap takes a number of years to fall to levels that are actually binding on emissions. The ability of generators to comply early and accumulate a bank of allowances for later compliance greatly reduces the present value of compliance costs. The results from the IPM model runs are somewhat hard to interpret, since the IPM modeling does not correctly reflect key provisions of the proposed rule. In particular, the IPM model makes the key assumption that all allowances in RGGI (including	

	Virginia's) will be sold at auction. It does not accurately reflect the free allocation of allowances to generators and, most importantly, it does not account for the output-based allocation of allowances. My information on this comes from Dr. Chris MacCracken, the lead modeler responsible for the IPM model runs at ICF. Dr. MacCracken noted that, while it might have been possible to account for output-based allocation, the normal implementation of the IPM model does not do so, and no such special accommodations were made in the modeling of Virginia joining RGGI. The failure to account for output-based allocation would change both the amount of leakage of generation from Virginia into non-capped states in the PJM RTO and the competitiveness of Virginia generation in the states that are members of both PJM and RGGI. One clear conclusion is that total CO_2 emissions are lower with output-based allocation than they would be without it due to reduced leakage and that this improved emission performance is accomplished at very modest cost. My conclusion is that Virginia joining RGGI at the lower cap of 28 million tons in 2020 is environmentally effective, with little expected leakage into the uncapped portion of PJM. The reductions are achieved for under \$4.50/ton of CO_2, a very modest cost for emission reductions consistent with what Virginia would need to do to bring its electricity sector in compliance with U.S. emission reduction obligations under the Paris Climate Accord. It is extremely important that Virginia make every reasonable effort to make its rule consistent with the rest of RGGI. It is only be working together as a block that states can achieve the most cost-effective reductions in emissions. When the Air Board added emission reduction provisions for the period from 2030 to 2040, it violated	

	this principle of comity with the other RGGI states. The history of RGGI makes it abundantly clear that the principle of establishing caps for the next decade based on the best available evidence on compliance costs and then periodically revising those caps downward as justified by newly available evidence has worked extremely well. The two rounds of reductions already in place and the reductions to take effect in 2020 provide ample demonstration of the value of this consensus-based, incremental strategy. The board's addition of ad hoc, distant future reductions that are inconsistent with the RGGI model rule, violates the RGGI comity principle and unnecessarily complicates Virginia's relations with the RGGI states. The board's actions were not based on any evidence but are, rather, numbers plucked out of the air with no basis in modeling or analysis. The change provides no assurances of additional reductions over what would be achieved through the normal RGGI process of periodic review and revision. This change was made against DEQ's best advice and in spite of a clear signal from RGGI representatives that the change would violate RGGI comity. As a result, the changes to the proposed rule that refer to reductions beyond 2030 should be returned to the language in the original proposed rule. Our objective should be to work with RGGI states to achieve the greatest joint reductions possible. It is a disservice to that objective to make ad hoc, purely symbolic statements about distant future reductions, when the RGGI states already have an effective mechanism for revising future caps in response to the evidence as it evolves over time.	
71. Southern Environmental Law Center (SELC) on behalf of Appalachian Voices and	As stated in our comments on the original proposal, we support a 2020 emissions baseline that best achieves DEQ's goal of reducing statewide carbon pollution. SELC agrees the re-proposed 2020 base budget of 28	Support for the proposal is appreciated.

Wetlands Watch	million tons does just that. The updated and revised modeling assumptions show that Virginia's CO_2 business-as-usual emissions will be 28 million tons of CO_2 in 2020. This baseline appears far more accurate than the originally proposed base budgets of 33 or 34 million tons, which were significantly higher than recent actual emissions. The new modeling relied on more current data and more realistic assumptions, incorporating increases in renewable energy and energy efficiency coming on line in Virginia as a result of the 2018 GTSA, new demand projections, updated natural gas prices, new RGGI states, and significant new clean energy deployments in the RGGI states. As a result, the updated model produced a more accurate business-as-usual scenario for 2020 than originally proposed, which relied on outdated assumptions. The GTSA requires Dominion and Appalachian Power to propose $1.01 billion in energy efficiency investments by 2028. Energy efficiency programs can significantly reduce peak demand. As we noted previously, a study of Virginia's possible energy efficiency future by Applied Economics Clinic found that under a medium efficiency scenario, total annual electricity sales in Dominion's territory could actually decrease. Indeed, the study shows annual efficiency savings between 1,813 GWh and 2,840 GWh by 2028 under low efficiency or medium efficiency scenarios, respectively. Given these significant potential demand savings from energy efficiency initiatives, it is clear that the re-proposed base budget of 28 million tons, which factored in future energy efficiency investments in Virginia, is more realistic than the original budgets. DEQ's decision to include these investments in the revised modeling is also consistent with a recent ruling from the SCC. In December 2018, SCC rejected Dominion's 2018 IRP in part due to	

	the failure to include $870 million in proposed energy efficiency investments in the IRP load forecasting. SCC insisted, and Dominion agreed, that a primary purpose of energy efficiency measures is to reduce load. As such, SCC required Dominion to assess the impact of the GTSA energy efficiency investments on load forecasts in its revised IRP. Through the GTSA, the General Assembly also announced its intention to develop 5,000 MW of wind and solar projects in the state by 2028. As a result, Virginia's in-state generation fleet will necessarily become less carbon intensive, helping to achieve the carbon reductions proposed. The originally-proposed base budgets did not include this increase in renewables as an assumption and therefore overstated future carbon emissions in the state. The new base budget of 28 million tons, which assumes 5,000 MW of renewables by 2028, is a more accurate reflection of future CO_2 emission levels. DEQ's consideration of new demand projections also produced a more realistic base budget. An updated demand projection is consistent with SCC findings in its December 2018 Final Order on Dominion's IRP. DEQ relied on Dominion's 2017 IRP load forecast in its original modeling; however, SCC concluded in December 2018 that Dominion's load forecast has been overstated for years, despite generally flat actual demand. Indeed, Dominion's load forecast was almost double PJM's projections. In light of this finding, and in light of decreased demand in RGGI states, SELC supports DEQ's decision to update demand projection and agrees this resulted in a more accurate beginning base budget and future reduction goals. The proposed base budget of 28 million tons--based on better modeling and more realistic demand projections--is well supported by the record.	
72. SELC	The proposal unambiguously applies	DEQ disagrees that the applicability of

	to fossil fuel-fired units that co-fire with biomass. In particular, the regulation defines "fossil fuel-fired" as "combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 5% of the annual heat input on the Btu basis during any year." The regulation then states that "[a]ny fossil fuel-fired unit that serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe shall be a CO_2 budget unit, and any source that includes one or more such units shall be a CO_2 budget source, subject to the requirements of this part." Together, these two provisions make clear that the regulations cover all units that co-fire fossil fuel with biomass, so long as the fossil fuel comprises more than 5% of the annual heat input. The only co-fired units that would not be subject to the requirements of the regulation are units where biomass accounts for 95% or more of the annual heat input, with fossil fuel accounting for 5% or less. Importantly, an owner of a co-fired unit subject to the regulation must obtain sufficient CO_2 allowances to offset all of the unit's CO_2 emissions. The proposed regulation makes clear that an owner or operator must hold allowances for "total CO_2 emissions . . . from all CO_2 budget units at the source." Since co-fired units that burn less than 95% biomass are by definition a fossil fuel-fired unit and a CO_2 budget unit, an owner or operator must have CO_2 allowances to offset all emissions from such a unit. We support this approach. Inclusion of all CO_2 emissions, regardless of fuel type, best achieves the goals of these carbon reduction regulations. Additionally, attempting to distinguish between CO_2 emissions from various fuel types would be difficult to implement and enforce, causing a significant administrative burden on both covered sources and DEQ. Thus, requiring that CO_2 Budget	biomass in both the proposal and re-proposal is unambiguous and has modified the re-proposal accordingly; see the current response to current comments 24 and 40 for further discussion. Every attempt has been made to make the regulation consistent with the applicable Virginia mandates as well as those of the RGGI program, including biomass applicability. Reducing the fossil fuel threshold from 10% to 5% is needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.

	Sources hold allowances for all CO_2 emissions makes good sense from a policy perspective and furthers the goals of the regulations. While we support the proposed regulation's coverage of co-fired biomass units, we reiterate our request that DEQ amend the regulation so that all biomass units with nameplate capacities equal to or greater than 25 MWe are subject to the requirements, not merely co-fired units. The science is clear: burning wood for electricity is not inherently carbon neutral and results in an immediate net increase of atmospheric CO_2 for decades to centuries. While including co-fired biomass units in the regulation is a good start, there is no principled reason to exempt other biomass units. Biomass units generate CO_2 emissions just like fossil fuel-fired and co-fired units, and should be covered in order to better reduce the carbon emissions.	
73. SELC	SELC reiterates its support for the set-aside to assist DMME in efforts to abate and control air pollution through energy efficiency programs. This set-aside will play an important role in both furthering the purposes of the regulations and offsetting the costs. In addition to reductions in demand, energy efficiency programs can result in lower costs for customers. In the study by Applied Economics Clinic, low efficiency or medium efficiency scenarios in Virginia could decrease customers' annual electric bills by $41 to $92 in 2028, with cumulative customer bill savings totaling $800 million-$1.7 billion between 2018-2028. The medium efficiency scenario can deliver up to 5.74% average reduction in bills in 2028. The set aside will play a key role in continuing to lower demand and, in turn, carbon emissions in Virginia, and will also be an important part of reducing program costs. We also reiterate our suggestion that a 10% set-aside would produce more benefits than it would increase costs for covered entities.	Support for the proposal is appreciated. DEQ agrees that energy efficiency is a cost-effective way to reduce carbon emissions. Once the program has operated for a period and can be evaluated through future program reviews, an increase in the set-aside may be considered at a future date.
74. Sierra Club	The re-proposed rule is	Support for the proposal is appreciated.

	unquestionably needed in order to protect the public by reducing CO_2 emissions from power plants located in Virginia and to do so by creating a CO_2 emissions market linked to the existing RGGI market for CO_2 emissions. Reducing CO_2 emissions is critical to protecting Virginia's citizens, natural resources, infrastructure and economy. Since comments were last submitted, a multi-agency, federal team issued the Fourth National Climate Assessment. That assessment leaves no doubt about either the link between climate change and human GHG emissions, including CO_2, or the urgency of taking actions to reduce those emissions. We request that the entire assessment be incorporated into the record, as it underscores the urgency to act. Another report recently issued by the IPCC further underscores the dangers of inaction or delayed action. It concludes that in order to avoid the dangers from increasing global average temperatures by 1.5°C, it is necessary to reduce GHG emissions by 45% by 2030 and to achieve zero-net CO_2 emissions by 2050. The proposed rule is thus directionally correct, but plainly insufficient and will need to be strengthened in the future.	Note that participation in RGGI as well as state-required program reviews will enable DEQ and the public to monitor program process and consider the appropriateness of any cap.
75. Sierra Club	In our April 2018 comments, we urged DEQ to set the initial base budget below 30 million tons and to revisit this initial budget in early 2019. We appreciate DEQ's responsiveness to this request and its current proposal to set the initial base budget at 28 million tons. This figure is consistent with modeling sponsored by NRDC and conducted by ICF using the IRP. It is also consistent with the trends in Virginia's power sector described in our previous comments, including the rapid decline in coal-fired generation in Virginia and flattening retail loads. The 28 million ton cap represents a far more realistic forecast of 2020 emissions from covered sources in Virginia and support this revised initial base budget. At the same time, note that the annual allowance budget in the current RGGI states has	Support for the proposal is appreciated. Participation in RGGI as well as state-required program reviews will enable DEQ and the public to monitor program process and the appropriateness of any cap.

	consistently been undersubscribed since the inception of the program. Most recently, 2018 emissions from CO_2 budget sources in the current RGGI states were 15% below the 2018 cap of 70 million tons, in line with the RGGI state's emission cap for 2023–five years ahead of schedule. To protect the integrity of the program to continue to provide climate and environmental benefits, it will be critical to continue to monitor the appropriateness of the cap level in conjunction with the other RGGI states and make appropriate adjustments in future program reviews.	
76. Sierra Club	In the re-proposed rule, any generating unit that burns more than 5% fossil fuels would require allowances to cover all of its CO_2 emissions, including emissions from co-fired non-fossil fuel. We strongly support requiring CO_2 allowances for all CO_2 emissions from generating units crossing the 5% fossil-fuel threshold regardless of the specific fuel to which the CO_2 emissions may be attributed. On the other hand, DEQ's Public Notice states that one of the substantive changes in the proposed rule "is an exemption of fossil fuel units that co-fire with biomass from CO_2 accounting and it specifically requests comments on coverage of CO_2 emissions from units that co-fire with both fossil fuel and non-fossil fuels." While we do not see such an exemption anywhere in the re-proposed regulation, we do comment on this issue and oppose any such exemption. We oppose any exemption for CO_2 emissions from burning biomass. In addition to CO_2 budget units that co-fire with fossil fuels, we urge that the final rule include, as CO_2 budget units subject to the allowance-holding requirement, generation units that combust biomass without fossil fuel. All biomass produces CO_2 emissions when burned, and biomass burns less efficiently than fossil fuels thereby producing more CO_2 per unit of	See the current responses to current comments 24 and 40 for further discussion of biomass. As discussed in greater detail in the current responses to current comments 24 and 40, this is a fossil fuel regulation. Reducing the fossil fuel threshold from 10% to 5% is needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.

	energy generated. Whatever may be said about using quick-growing crops as biomass, wood-based biomass is the least likely to result in CO_2 recapture within a time frame helpful to avoiding the looming climate crisis. Like all biomass, woody biomass produces more CO_2/MWh generated than burning coal or natural gas. In addition, if full recapture through regrowth of woody biomass does occur, it will be decades into the future. The recapture will also be followed by a new round of cutting and burning so another major pulse of CO_2 emissions will promptly follow. EO 11 addressed CO_2 emissions from electric power facilities, without saying that CO_2 from biomass would be excluded from coverage by Virginia's rule. Further, while the RGGI model rule covers fossil fuel-fired generation units (XX-1.2, definition of "unit" and XX-1.4), the model rule provides the option of, but does not require, excluding the units' emissions from combustion of biomass and limits that exclusion option to eligible biomass (XX-1.2, definition of "eligible biomass" and XX-6.5(b)(1). Exclusion of non-fossil-fuel emissions is not necessary for consistency with either EO 11 or with RGGI. Second, there is no legitimate reason to exclude biomass-based generation from the requirement to obtain allowances. The premise for exempting CO_2 emissions from burning biomass is that the emitted CO_2 will eventually be recaptured by regrowth of the feedstock and that future recapture is somehow sufficient to mitigate the climate damages from current CO_2 emissions. Those assumptions are faulty in several respects, particularly as they relate to wood-based biomass. CO_2 emissions per MWH of electricity generated from biomass are substantially higher than from coal and natural gas because biomass burns less efficiently. Co-pollutants from biomass combustion--e.g., particulates--are large in quantity and harmful to human health. If waste	

	wood is included in the mix, toxic and metal pollutants can also be emitted. Adverse climate and health impacts from burning biomass will not be neutralized by sequestration of CO_2 through regrowth, even assuming that the biomass is eventually replaced with comparable forests. Exempting biomass from carbon prices amounts to a harmful subsidy for CO_2 emissions from biomass. That subsidy of free carbon pollution rights would undercut beneficial investments in zero-carbon alternatives, such as solar, wind and energy efficiency, which mitigate climate harms in both the near-term and long-term. The subsidy is particularly unjustifiable given that biomass emits more CO_2/MWH than fossil fuels. There is no support for the implicit assumption by biomass-advocates that forests will be regrown in a sustainable way or in sufficient quantities to recapture that CO_2 is emitted during the life of this program. RGGI purports, in the option that it allows for excluding emissions from eligible biomass, to limit the exemption of biomass to sustainably harvested biomass. However, adopting that approach would require DEQ to adopt sustainability regulations and commit personnel and resources to monitor and enforce sustainability the next 50-100 years. Past investments in large biomass facilities do not deserve special treatment any more than past investments in fossil fuel-fired facilities. CO_2 emissions are harmful in both cases. At a minimum, all new plants burning biomass without fossil fuel should be required to acquire allowances for all CO_2 emissions, just like fossil fuel-fired plants are required to cover all CO_2 emissions. Third, the recent IPCC report recognizes that we need to achieve a 45% CO_2 emissions reduction economy-wide by 2030 and achieve net zero emissions by 2050. It makes no sense to subsidize biomass emissions of CO_2 by exempting them from the requirement to obtain CO_2	

	allowances. With the inevitably slow growth of replanted forests and future cuttings of those trees, exempting woody biomass will help to defeat the 2030 and 2050 goals for CO_2 reductions. The climate crisis will never be resolved if previously built woody-biomass facilities (whether or not they co-fire fossil fuel) are granted exemptions or if incentives are created to build new wood-fired plants or to operate existing ones more. Fourth, changing the rule to exempt CO_2 from non-fossil fuels would require adoption and enforcement of a new regime of measurement, accounting and reporting to segregate fossil-fuel and non-fossil-fuel CO_2 emissions from covered generation. Without such an additional layer of measurement, accounting, reporting, inspections and auditing, the rule simply would not work for co-fired units.	
77. Sierra Club	CO_2 emitted now or over the next few decades will heat the atmosphere and oceans for millennia. It does not matter whether the emissions come from biomass or any other materials. There is thus no reason to exempt emissions from burning solid wastes or any other fuel. In the case of co-firing with municipal wastes, there are added issues. A significant portion of the heat input for an incineration generation unit burning municipal solid waste comprises plastics, often supplemented by natural gas, petroleum, or coal. Because plastics are made from the hydrocarbons in natural gas, petroleum, or coal and 9VAC5-140-6020 C defines "fossil fuel" as "natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material," fossil fuel includes, on its face, plastics. Further, municipal solid waste-based generation not only involves co-firing of fossil and non-fossil fuel, but also such generation results in significant emissions of CO_2, as well as extremely harmful co-pollutants. As of 2015, plastics comprised 13.1% of municipal solid waste in the U.S. and	There are costs and benefits associated with WTE facilities; however, plastics are not, in common parlance, considered to be fossil fuels, nor are all plastics derived from petroleum. Ultimately, municipalities must make decisions about the most environmentally protective means of handling their waste, and follow current state and federal pollution control requirements.

	15.9% of municipal solid waste combusted for energy. Because plastics have significantly higher heat content than other material in trash, their share of incinerator heat input likely comprises more than their percentage by weight. Consequently, under the 5% fossil-fuel threshold for units to be covered units, existing and new incinerator generation units would likely be CO_2 budget units and covered by the requirement to hold allowances. Inasmuch as such units produce CO_2, emissions while generating electricity, they should be covered by the rule. That will tend to help reduce overall CO_2, emissions and not, by exempting them, undercut zero-carbon alternatives.	
78. Sierra Club	The costs of the proposal for a consignment auction are minimal and the benefits are great, particularly when Virginia considers the costs and harms from continuing business as usual. Actual experience by current members of RGGI demonstrates that benefits have outweighed costs, their residents have experienced improved health outcomes, and that actual costs have consistently come in well below earlier forecasts. Moreover, the costs incurred in conducting a consignment auction are minor compared to the revenues from the sale of consigned allowances, even as incentives are created to find cheaper, cleaner energy sources. On the benefit side, Virginia and its residents and businesses are already experiencing direct and indirect harms from human-caused climate changes. These are especially notable along its coastal areas, in rising health harms from heat-illnesses and smog, and in harms to property and agriculture from extreme precipitation and storm events. Virginia faces much more severe harms as a result of climate change. The growing harms include those to its coastal and along tidal estuaries; to the health of its citizens who face greater direct harms from temperatures and pollution; to public and private property from increased flooding and wind damage from	Support for the proposal is appreciated.

	storms and extreme rain events; to its agriculture and viniculture from heat and weather disruptions; to its natural heritage, including forests, streams and wildlife; and to its economy, which will be directly harmed by the aforementioned disruptions and further harmed by delaying investments in the GHG reductions that will become more urgent and disruptive by delaying them. Not only will Virginians benefit from reducing CO_2 emissions sooner rather than later, their economy will benefit from incentivizing low-emission investments rather than high-emission investments that will likely be stranded in the future. The longer we wait, the worse the transitional costs will be. As noted above, according to the IPCC, reducing GHG emissions by 45% from 2010 levels by 2030 is critical in order to keep global temperature increase from exceeding 1.5°C above pre-industrial levels. The certainty of harms and the nature and magnitude of those harms are spelled out in greater detail in two recent publications as part of the 4th National Climate Assessment. These documents, which are incorporated by reference, leave no doubt about the dangers posed by climate change and about the reality that climate change is already harming the U.S., including Virginia.	
79. Sierra Club	Farm and forest land preservation are threatened by climate change. The proposal will promote farm and forest land preservation by making progress in addressing climate change. The co-benefits of reducing co-pollutants from dirty power plants will also likely help farms and forests. If the final rule were to exempt CO_2 emissions from biomass, the result could undercut forest land preservation by subsidizing, continued and increasing power generation and CO_2 emissions from woody biomass. Harvesting woody biomass would encourage harm to forests and the lands that will be disturbed by continued or increased harvesting. Meanwhile, subsidization of CO_2 and other	The commenter's concerns are acknowledged; however, as discussed elsewhere, DEQ's directive is to address fossil fuel-fired power plants.

	pollution from biomass would undercut reductions in CO_2 emissions from fossil fuel generated electricity. This could also undercut preservation of farm land by incentivizes expansion of tree farming for the purposes of feeding wood pellets or other wood products to biomass-fired power generation. It could also encourage diversion of land dedicated to food production to energy production. That would not be in the public interest.	
80. Sierra Club	As defined in § 2.2-4007.1 of the Virginia Code, small business means a business entity that is independently owned and operated, and employs fewer than 500 full-time employees or has gross annual sales of less than $6 million. No company covered by the proposed rule that would be deemed a small business under this definition. Any power plant having generating units of 25 MW or more will have gross annual sales well over $6 million. Further, a trading mechanism is inherently designed to achieve goals with the least financial and administrative burden. The re-proposed rules generally follow RGGI, which has successfully functioned for a decade. Economies in RGGI states have grown since the RGGI's implementation.	Support for the proposal is appreciated. DEQ agrees with the commenter's assessment of small business applicability.
81. Sierra Club	We appreciate the inclusion of 9VAC5-140-6440, which recognizes the need to both evaluate the impact of the program on environmental justice communities and also for meaningful participation from these communities. First, we recommend that when DEQ evaluates impacts on these communities that the evaluation considers not only direct emissions of CO_2 but also impacts from co-pollutants as well as the cumulative impacts from CO_2 budget sources and other polluting facilities. In conducting evaluations to assess any adverse impacts on communities, California's AB32 Adaptive Management Plan is a good example for a state planning to undertake such an evaluation. Co-pollutants can have serious health consequences for people in their vicinity. When evaluating impacts of	Support for the proposal is appreciated. Virginia will be the first RGGI member state to explicitly address environmental justice in its RGGI implementation rule. As discussed in greater detail in the initial response to comment 55, DEQ has a robust community involvement program, and the addition of environmental justice review and analysis in this regulation builds on this important commitment. Further discussion of Virginia's environmental justice efforts is provided in the current response to current comment 33.

	co-pollutants DEQ should look at total emissions of co-pollutants from participating fossil fuel-fired electric power generators. There is evidence that a disproportionate number of environmental hazards, polluting facilities and other unwanted land uses are located in communities of color and low income communities. This has almost certainly played an important role in the disproportionate exposure to air pollution experienced by residents of various environmental justice communities. The concept of cumulative impacts refers to the interaction, and the risks created and effects experienced due to the interaction, of multiple pollutants emitted by multiple polluting facilities located in a neighborhood. DEQ must not solely evaluate pollution from participating generators in static isolation. As a starting point DEQ can use EJSCREEN to map environmental concerns in order to identify issues for further analysis. EJSCREEN's supplementary maps feature provides information on environmental concerns and sources of air and water pollution derived from EPA databases. EPA's Framework for Cumulative Risk Assessment provides guidance on undertaking a cumulative impacts assessment when evaluating both chemical and non-chemical stressors that may be relevant to identifying environmental justice concerns. Second, we recommend that if DEQ's evaluation shows adverse environmental or socioeconomic impacts, or would add to cumulative impacts to communities that already face environmental hazards, DEQ include measures to avoid or mitigate these impacts, and do so in coordination with these communities. A range of options to be considered could include the adoption of regulatory requirements, coordination with other agencies to provide additional incentives for energy efficiency or other emission reduction activities within the community, or	

	modifications to the regulation. Third, we recommend that the DEQ develop and implement a plan to ensure increased participation of EJ communities consistent with the National Environmental Justice Advisory Council's Model Guidelines for Public Participation, which updated its Model Guidelines for Public Participation in 2013. The document included critical elements of effective community engagement, several of which we urge DEQ to draw upon in its efforts to develop and implement a plan to ensure increased participation of environmental justice communities in the review pursuant to 9VAC5-140-6440.	
82. Sierra Club	In 9VAC5-140-6190 C, the rule wisely states that, absent a future amendment, annual reductions of CO_2 allowances will continue in the period 2031-2040 at the same rate as in prior years. We understand that RGGI has questioned this provision. This provision is uniquely important for Virginia. In order to make reasonable judgments about applications to build generation, storage and transmission, utilities and the SCC need clear guidance from environmental regulators that CO_2 limits will continue to decline after 2030. A rule requiring 10 years of CO_2 reductions followed by flat CO_2 limits thereafter does not go far enough. Generation, transmission and storage decisions that assume no CO_2 reductions after 2030 would have badly skewed assumptions about the economic life-spans and operating costs of possible projects. When considering applications to build new electrical generation, the SCC's powers are limited by permits granted by DEQ. If DEQ grants permits to electric utilities to emit a specified level of CO_2, then the law prescribes that "[i]n order to avoid duplication of governmental activities,… the Commission shall impose no additional conditions with respect to such matters." Thus, unless Virginia's	As discussed in the current response to current comment 54, DEQ agrees with RGGI that participation in the RGGI market must be fully compatible with the existing RGGI program, which is a consensus organization. Regularly performed program reviews in concert with the other RGGI states are essential in order for the program to function properly, and an individual state going beyond those protocols is incompatible with the consensus basis of the organization. Virginia's control of CO_2 is not limited to participation in the RGGI program, which is one element in a suite of efforts to control this and other GHG pollutants. Effective participation in RGGI means operating within RGGI's unique program requirements and restraints. This does not limit the state's ability to control GHG by other means. For example, DEQ has recently initiated an investigation into additional controls on natural gas transmission. Moving forward, other actions may be considered as well. RGGI has operated successfully for 10 years, and DEQ sees no reason to disrupt this process or attempt to go beyond existing program review additionally required by RGGI requirements and Virginia law.

	final regulations prescribe a CO_2 reductions for the period 2031-2040 (preferably longer), utilities will argue that the SCC's review of proposed new carbon-polluting projects must assume that CO_2 emissions limits will not decline after 2030. It will not be enough that RGGI plans to periodically consider further reductions of CO_2 emissions. Nor will it be enough that there is a scientific consensus that CO_2 emissions be sharply reduced until net-zero emissions are achieved as early as 30 years from now. By prescribing flat CO_2 emissions caps after 2030, DEQ could create a fictional basis for future evaluations of certificates of public convenience and necessity. Virginia has legally-protected monopoly utilities that own nearly all the generating capacity that supplies retail energy in the state. Unlike competing generators in other states, Virginia utilities do not bear the financial risks of building projects that are later required to shut down or throttle back due to revised environmental regulations. As a general matter, they are able to impose risks of SCC-approved construction projects on customers. Because generation lasts for decades, it would be a mistake to discourage Virginia from adopting regulations that show continued CO_2 reductions well beyond 2030. To do so would send misleading signals to the SCC and Virginia's electric markets. This would cause higher costs to consumers and harmful CO_2 emissions for decades, and could erect potential barriers to Virginia's agreeing with RGGI to implement future reductions. Thus, creating an illusion that CO_2 emissions limits will remain flat after 2030 would be very harmful to utility regulation and consumers. Virginia's proposal to presumptively require continued reductions beyond 2030 is consistent, not inconsistent, with RGGI's model for continuous progress reducing CO_2 emissions.	

	First, for the years 2020-2030, Virginia will reduce CO_2 allowances at a rate equal to 3% of the first year, just as provided for in its discussions with RGGI. Second, while Virginia's proposed schedule for continued reductions beyond 2030 is needed, Virginia will obviously work with RGGI to make reasonable adjustments in order to remain linked to the RGGI market. Adopting provisions, at this time, that would require continued reductions in 2031-2040, does not prevent DEQ from changing the pace of reductions to meet the emerging needs and the outcome of future negotiations with RGGI members. Indeed, Virginia will be far better positioned to make adjustments to the post-2030 emissions levels, if it clearly puts utilities, customers and others on notice now that they should expect further reductions after 2030 and plan accordingly. DEQ's ability to work with RGGI to extend reductions in the future would be hampered if misleading signals now led to stranding utility assets. Third, it should be recalled that Virginia is far behind RGGI in its reductions of CO_2 emissions. While RGGI has stated its plan to reduce CO_2 emissions by 65% by 2030, Virginia will be nowhere near that level of reductions. It will have to continue reducing its CO_2 emissions long beyond 2030 just to catch up. Thus, there is no inconsistency. Fourth, it would be unfair for Virginia to be prevented from achieving at least as much total emissions reductions as current RGGI states, particularly given the health and economic benefits that have been achieved by reducing emissions in the RGGI states. Fifth, we know from volumes of scientific studies that much greater CO_2 reductions will be needed as we head toward 2050, just to keep worldwide temperatures from rising 1.5° to 2.0°C. Continued reductions proposed from 2031-2040 would still leave Virginia well short of those goals. Thus, it would be unreasonable for the regulation not to specify a presumptive path for carbon	

	emissions reductions after 2030. Indeed some RGGI members have already announced their intention to cut their CO_2 emissions well beyond the levels set forth in the latest RGGI plans.	
83. Sierra Club	The rule needs to be modified to prevent generators from endeavoring to avoid application by manipulating the size of their units. The re-proposal to cover existing units serving a generator of 25 MWe or larger is generally consistent with RGGI's model rule. However, unlike RGGI's model rule, the re-proposed rule leaves a door open to manipulation of the size of units in order to evade CO_2 allowance requirements. The rule should be clarified to state that the 25 MWe threshold only needs to be crossed once after a fixed historic date to trigger coverage by the rule. To do this, 9VAC5-140-6040 A should be modified to state that the rule covers units serving a generator having a nameplate capacity of 25 MWe or more "at any time on or after" a fixed date. Currently, that provision simply states that fossil fuel-fired units "serving" a generator of at least 25 MWe are covered. Because 9VAC5-140-6040 A specifies no time frame, the re-proposed rule can be interpreted as covering only units serving such a generator at the time the provision is applied and not units if and when they change to serving a different generator with, or modify their existing generator to have, slightly less than 25 MWe capacity. It is not clear that such activity would be barred by Virginia's rule prohibiting piecemeal carrying-out of an operation to evade regulation (9VAC5-20-70). The language of the re-proposed rule may create a loophole for units currently subject to the rule to escape coverage through such actions. In addition, this language is contrary to the approach in the RGGI model rule, which specifies a time frame (i.e., "at any time on or after January 1, 2005") in the applicability provision (in XX-1.4(a)). Alternatively, the "on-or-after"	As discussed in the initial response to initial comment 151, the applicability limit is indeed designed to be consistent with the RGGI Model Rule. 9VAC5-20-70 prohibits circumvention of air quality requirements by constructing multiple facilities in a piecemeal fashion in order to avoid regulation. DEQ believes that the declining emissions cap will encourage the development of renewable energy and energy efficiency, not the construction of multiple smaller facilities which are less efficient. Based on the history of prior emissions trading programs, DEQ also does not believe that there is a significant risk that a CO_2 budget source would go through the considerable cost and effort to de-rate the nameplate capacity of its generators in order to evade coverage under this rule. Finally, there are very few sources and units at the lower end of the applicability level where such a modification would be feasible. The applicability of the rule to new units and the applicability threshold are consistent with RGGI.

	date could be shortly prior to the first notice that a plant might be covered by CO_2 regulations (e.g., January 1, 2014, which would have been shortly prior to the proposal for the CPP, which may have created a regulatory incentive to manipulate a generator's size or configuration). In any event, facilities should not be able to evade compliance by making changes that would alter a facility's size or configuration. The rule should also be modified to require units built after the rule is issued (i.e., new units) serving generators with a nameplate capacity less than 25 MWe to obtain emissions allowances. We suggest the threshold for new generators be set at 15 MWe or not more than 20 MWe. This is needed in order to send CO_2 regulatory and price signals to a broader pool of new generators and to prevent gaming that would undermine the regulation's CO_2 reduction goals and that would be unfair to existing generators covered by the rule. Within the RGGI region, there are examples of recent proposals for multiple generation fossil fuel-fired units each just below the 25 MWe compliance threshold. Since economic efficiencies and operating efficiencies would ordinarily support larger units, the sizing appears clearly to be driven by a desire to emit CO_2 without limits, thereby undercutting public health and the goals of the regulations. A lower size threshold for coverage of new units would better protect the public from emissions of CO_2 and co-pollutants, remove an unintended incentive for building less efficient fossil fuel generators, and protect the integrity of allowance markets. Since developers would have notice of the allowance requirement for new generation, no unfairness would result from imposing a lower size threshold for such generation. Building zero-carbon generation and storage would always be options for designers of new projects. We submit that units	

	placed in service after January 1, 2019 (or, at most, two years after the proposed rule was announced) would fairly be considered new.	
84. Sierra Club	We support DEQ's decision not to implement a regime of offset allowances. Such a scheme would require an extensive set of rules defining the permissible scope offset allowances and a very substantial expenditure of Virginia's administrative resources to assess proposals, to audit and verify actual compliance and benefits, and to bring enforcement actions to police violations. The complexity of offset arrangements is demonstrated by the facts that roughly one-third of the RGGI model rule are devoted to restrictions on, and administration of, offsets and that relatively few offset projects have been approved. The potential benefits would be far outweighed by the costs.	Support for the proposal is appreciated.
85. Sierra Club	Changes needed to clarify and enhance operation of the final rule are offered.	DEQ believes that the commenter's concerns are addressed by meeting the specific technical comments provided by RGGI.
86. Tenaska	The re-proposed regulation presents a base budget of 28 million tons. Actual CO_2 emissions from anticipated covered facilities were about 32.6 million tons in 2018. This would require a 14.1% reduction in two years to comply with the 2020 base budget, an average of 7.1% per year, or more than double the proposed 3% annual cap decline in subsequent years. Tenaska strongly suggests DEQ consider a higher base budget, such as 30 million tons, in the event 2019 emissions are similar. Tenaska continues to strongly favor the "generation updating" approach, whereby covered facilities are allocated allowances according to their respective historical annual net generation (MWh_{net}) as compared to the total aggregate generation from covered facilities, averaged over the immediate three calendar years, updated annually (i.e., on a rolling 3-year average). This approach best meets the intent of the regulation, in	See current comments 30, 39 and 71 for a discussion of the final base cap. DEQ is assisting affected sources in meeting compliance costs by issuing allowances. The amount of compliance costs covered by the allowances will depend on business decisions made by any individual facility. If a facility stays within the budget, it will not incur costs. DEQ agrees that other pathways to CO_2 reductions are important, but the scope of the regulation is limited by executive order of the Governor in accordance with state law. The 5% DMME set-aside as well as other ongoing programs such as GTSA will provide additional incentives for energy efficiency and renewable energy.

	that it incentivizes, or rewards, more efficient units that emit less CO_2 per unit of power produced. As presented several times during the Regulatory Advisory Panel meetings, Tenaska's Virginia Generating Station in Fluvanna County currently operates under a long-term contract with a third party, whereby the third party procures the fuel and purchases the generated electricity. Under the terms of the agreement, Tenaska believes it has the ability to pass through to its customer costs for things such as emissions allowances, whether they be for the Acid Rain Program, CSAPR, or any future carbon trading scheme. However, Tenaska's customer has taken the position that Tenaska does not have such a pass through right. These costs are projected to be $1.45/MWh in 2020 and rising to $1.81/MWh in 2030, representing an average increase of 5% over the projected wholesale power price. To the extent Tenaska's allowance allocation is not sufficient to cover actual emissions and is required to purchase allowances and is unable to pass through those costs to its customer, it will be disadvantaged as compared with other generators that can either recoup those costs or that have no costs due to their location in another PJM state without a carbon pricing scheme (e.g., Pennsylvania and West Virginia). Several current RGGI states and every major proposed federal CO_2 cap and trade legislation have recognized this predicament and provided various forms of relief, such as creating an allowance setaside/reserve account for free allocations or offering allowances at a reduced price. Tenaska requests DEQ also recognize this and either create a reserve account (as currently proposed for DMME to fund energy efficiency projects) sufficient to cover net allowance obligations for LTC holders in the event it is needed or simply exempt long-term contract holders for the life of the applicable	

	contract(s). Tenaska believes the reserve account would be less disruptive to the program as it would alleviate LTC units entering and exiting the program. We encourage DEQ to expand the scope of the regulation to include additional sources and seek meaningful reductions in other sectors of the economy, including mobile sources, if the consequences of climate change are to be avoided. One such way is to remove the exemption in 9VAC5-140-6040 B. CO_2 emissions from such facilities are no less potentially harmful than those from units that generate electricity for off-site use. Neither the RGGI Model Rule nor the environment make such a distinction and neither should DEQ.	
87. Virginia Advanced Energy Economy (AEEE)	Virginia AEE supports the revised regulation. The proposal will help to make our energy economy more secure, clean, and affordable, further bolstering Virginia's economy while reducing emissions. We also support the structure of the regulation, which will allow Virginia to integrate its' carbon market with other state and regional markets. Such integration will help the state reduce emissions through more efficient and cost-effective approaches. In April 2018, we submitted public comments expressing our support for the original draft regulation. Those detailed comments, which contain extensive analysis of the economic dynamics around carbon regulation in Virginia, accompany this submission. The revised regulation largely maintains the original structure of this carbon trading regime. As such our support for the regulation is unchanged and the analysis conducted in 2018 remains applicable. The chief difference between the revised rule and that originally proposed is the starting cap. In 2018, the board proposed a starting cap of 33 or 34 million tons of CO_2 per year. At the time our analysis indicated that, using advanced energy resources, the state would not only meet, but in fact	Support for the proposal is appreciated. As discussed in the current response to current comment 11, DEQ recognizes the value of the voluntary renewable energy market as an important tool in reducing carbon pollution. The structure of the general 5% set-aside will be under the purview of DMME, which is the appropriate state agency to implement renewable energy and energy efficiency programs.

	exceed its carbon reduction target, reducing emissions from the generation sector to approximately 19.7 million tons per year in 2030. The revised rule proposes a starting cap of 28 million tons, with an annual reduction of 3%. We support this revised cap. Per our analysis, using advanced energy resources such as efficiency and renewable generation, Virginia should be able to meet cap reductions each year through 2030 with little to no adverse impact upon rates, even with a lower starting cap. In fact, depending upon the mix of energy resources utilized in compliance, Virginia consumers may see their rates decrease as a result of this rule. By reducing the quantity of carbon credits in the marketplace, this cap reduction should raise the value of zero carbon resources, such as renewable generation and energy efficiency. This may, in turn, prompt the deployment of such resources above and beyond what we projected in our analysis last year. Added deployment of advanced energy is good news for Virginians. As our prior analysis indicates, investment in renewables and efficiency is a source of net job creation for Virginia. Additional investment should, therefore, help to create still more jobs in Virginia. Such projects, be they wind and solar farms or efficiency investments, are likewise shown to generate new in-state investment and tax revenue for the state and locality in which such projects are located. Additional investment should, therefore, produce more in-state investment and revenues. Virginia has the opportunity to adopt a regulatory system that allows the state to meet its environmental goals while creating new jobs, investment, and tax revenues and leaving rates largely unchanged. As our analysis demonstrates, we have at our disposal the advanced energy resources necessary to accomplish	

	this balancing act. Therefore we encourage the board to approve the revised draft rule, and for policymakers throughout Virginia to advance rules and regulations that allow Virginians to fully access the advanced energy economy.	
88. Virginia Agribusiness Council (VAC)	We ask that you restore the language clarifying that CO_2 emissions from CO_2 budget units that do not exclusively combust fossil fuels are exempt from the proposed rule. VAC has consistently opposed any regulation that does not treat biomass as carbon-neutral, regardless of whether or not it is co-fired with fossil fuels. A study by NCASI found that there are substantial GHG reduction benefits in using forest products manufacturing residuals for energy in the pulp, paper, packaging and wood products industry. Accounting for fossil fuel displacement and avoided emissions associated with disposal, the use of biomass residuals each year avoids the emission of approximately 181 million metric tons of CO_2. Indeed, just last month, Congress enacted, and the President signed appropriations legislation reaffirming that federal regulatory policy should reflect the carbon neutrality of forest-based renewable biomass. Therefore, we ask that the board restore the clarifying language for biomass emissions and ensure there is a strong exemption for existing industrial facilities.	The biomass issue has been addressed accordingly; see the current responses to current comments 24 and 40. See current comment 28 for further discussion of industrials.
89. Virginia Chamber of Commerce	In December 2017, the Virginia Chamber released Blueprint Virginia 2025, a comprehensive business plan outlining the business community's recommendations for making Virginia the best state in the nation for business. Throughout the stakeholder engagement process, the Chamber heard from business leaders on how reliable, affordable energy sources are paramount to improving Virginia's business climate. RGGI is not consistent with the recommendations in Blueprint Virginia and could jeopardize future business investment and economic growth in Virginia. As such, we encourage the board to not	The analyses conducted by ICF and Analysis Group suggest that impacts to power prices will be minimal, especially considering the allowance allocation approach that will benefit electricity consumers. RGGI has been in operation for 10 years and has been studied extensively for its impacts on public health, the economy and jobs. A number of independent analyses are available at the RGGI Project Series website: rggiprojectseries.org. DEQ has identified several issues with the SCC analysis; see the current

	move forward with finalizing this regulation, or amend the proposal to alleviate the concerns of the business community. Ensuring competitive, affordable energy rates for businesses and residents is a central component of Blueprint Virginia's energy chapter. Energy rates factor into state business rankings, and Virginia's affordable electric rates, which were 12% lower than the national average in 2017, provide a competitive advantage compared to surrounding states, thus incentivizing businesses to expand and relocate to Virginia. That said, joining RGGI or establishing a cap-and-trade program would eliminate that advantage by increasing electric rates for residents and businesses. An SCC analysis concluded that average residential customer bills could increase by $7-12 per month if Virginia joined RGGI. Increased energy costs would also prevent existing Virginia-based companies from investing in more productive uses of their capital, such as facility improvements and hiring additional workers. Finalizing the proposal and joining RGGI would likely lead to job loss in the power generation sector and have a negative impact on rural Virginia. Forcing the premature closure of coal-fired power plants and other carbon-intensive generating units would result in the unemployment of union and non-union workers, who could face difficulty finding similar employment opportunities in the energy field. Further, many of the large coal-burning generation units in Virginia are in rural areas, which depend on these facilities for a sizable portion of their tax revenue. If plant closures were to occur in the short term as a result of RGGI, counties and municipalities would have to recoup that revenue by raising taxes on residents and businesses or cutting their budgets and reducing available services.	response to current comment 20 for further discussion. Leakage is not likely to occur; see the current response to current comment 31.

	Reductions in Virginia power generation would likely fail to accomplish region-wide environmental benefits due to carbon leakage, where emissions are moved from nearby states that have not implemented similar carbon regulations. Modeling performed for DEQ by ICF projects that joining RGGI would result in a net decline of in-state generation in Virginia of approximately 2.3 terawatt hours in 2030 and a 33% increase of net electricity imports. Most of those imports would come from surrounding states in PJM that have higher carbon-intensive profiles than Virginia. Virginia's carbon footprint from power generation is already significantly cleaner than most other states in PJM, so it is alarming that the board would pursue a policy action that increases energy costs and jeopardizes job creation while not making significant progress on reducing carbon emissions throughout the mid-Atlantic region.	
90. Virginia Chamber of Commerce	The re-proposal reduces the starting emissions cap to 28 million tons, a more than 15% reduction from the board's original proposal. Under this revised base line, electric generators in Virginia would have to scale back or completely shutter existing facilities powered by fossil fuels at a faster rate. Utility companies and other businesses in the energy supply chain have already made significant investments to curtail carbon emissions, and this proposal would require more drastic emissions reductions and result in higher investments costs, which would be passed along to ratepayers. Joining RGGI and imposing an initial 28-million-ton carbon emissions cap would inevitably increase costs to consumers and threaten energy stability. We request that the board increase the 2020 and subsequent emissions cap to a significantly higher threshold. The revised proposal allows for	The cap is addressed in current responses to current comments 30, 39, and 71. Post-2030 reductions are addressed in current response to current comment 54. Biomass is addressed in current responses to current comments 24 and 40. New industrial facilities will be subject to the regulation. This is because of long-standing clean air regulatory policy: new facilities are better positioned to be aware of, and to apply controls, in response to new regulations. Existing facilities have less advance planning ability and reduced ability to more effectively control pollution than new facilities. The industrial exemption is intended to enable existing facilities to better comply with the regulation. Applying the regulation to new facilities is needed to address carbon pollution from facilities that will be better able to comply, and not serve as an incentive for the construction of new fossil

	adjustments to the emissions cap each year after 2030 and includes a default option whereby the annual cap is lowered by 840,000 tons each year from 2031-2040 if the board fails to make any adjustments. Not only does this provision create uncertainty for utilities looking to make long-term investments but it is also inconsistent with the RGGI model rule, a concern addressed in comments submitted by the RGGI states themselves. It is important that regulations promulgated to join a larger framework should not be more restrictive than the existing requirements of such framework, which is why we urge the board to remove this provision. To reduce uncertainty, the final regulation should explicitly state that the emissions from biomass do not require emission allowances. Earlier this year, Congress passed legislation recognizing the benefits of biomass as a carbon-neutral energy source, and even RGGI does not require allowances for emissions from eligible biomass combustion. The board should clarify that the proposal only regulates emissions from fossil fuel combustion, which has been our understanding throughout the rulemaking process. Several of our members have suggested that the board re-insert the phrase "that have been generated as a result of combusting fossil fuel," which was included in the original version, to confirm that the regulation does not apply to biomass. Although the regulation includes an exemption for carbon emissions from certain industrial facilities, the exemption only applies to units in existence as of January 2019. As a result, future industrial facilities with on-site generation above 25 MW would be subject to the carbon program, which would raise compliance costs on manufacturers and other industry-related businesses. This provision would disadvantage	fuel units that would not be covered by this rule.

	those businesses that decide to construct on-site generation facilities after 2019 and could undermine the state's ability to attract larger manufacturers, thus harming our business climate compared to other states. We request that the board amend its industrial exemption to include existing and future on-site generating facilities.	
91. Virginia Energy Efficiency Council (VAEEC)	Energy efficiency can play an important role in reducing carbon emissions as one of the most practical, no-cost/low-cost tools to spur economic development and to reduce energy consumption and dependency on fossil fuels. Many analyses have found energy efficiency measures to be the most cost-effective and quickest way to address climate change while simultaneously reducing energy usage and cutting utility bills. According to a report by the American Council for an Energy-Efficient Economy (ACEEE), energy efficiency programs across the U.S. have reduced carbon pollution by 490 million tons and saved individual households an average of $840 in 2015. We applaud the 5% carve out for energy efficiency programs in the Carbon Trading Rule. Last year, ACEEE ranked Virginia 26th out of 50 in their 2018 State Energy Efficiency Scorecard. Moving up three places from 2017 underscores the work we have done to advance smart energy efficiency policies and initiatives. However, even more can be done to help Virginia break into the top 25. The passage of the Grid Transformation and Security Act of 2018 paves the way for greater opportunities as well. This legislation provides tremendous opportunities for energy-saving programs over the next decade, including a combined commitment by the electric utilities to spend over $1 billion on energy efficiency programs. Energy efficiency has tremendous potential to drive economic growth, create jobs, shrink utility bills, conservation natural resources, and reduce pollution across the state. These new	Support for the proposal is appreciated. DEQ agrees that energy efficiency will play an important role in reducing carbon pollution in the Commonwealth.

	programs, in addition to the energy efficiency carve out of the revised rule, will propel Virginia into the spotlight as a leader on energy efficiency while protecting the health and welfare of all Virginians.	
92. Virginia Forestry Association (VFA)	The revised proposal would provide unfavorable outcomes that significantly differ from the intent of the original version. These results, in fact, would be detrimental for forest products industry operations and important biomass markets for forest landowners. The revised regulation would apply to biomass-fueled utilities that co-fire with 5% or more fossil fuel. Also, biomass-based CO_2 emissions from those facilities are not recognized as carbon neutral. In addition, it does not clearly exempt all existing and potential new industrial facilities from the program, erroneously regulating new industrial boilers that burn carbon neutral biomass. We urge DEQ to revise the regulation to clarify that it only applies to GHG emissions from fossil fuel combustion and not from biomass combustion, officially recognizing biogenic carbon dioxide emissions as carbon neutral irrespective of whether other fuels are co-fired, and clarify that new and existing industrial facilities and boilers are clearly exempt from any allowance obligations. Because of the confusion created by the changing policy in the process of developing this regulation and the potential for detrimental outcomes to the forestry community, VFA also opposes Virginia's participation in RGGI at this time.	See the current comments 24, 38 and 40 for more detailed discussion of how biomass will be treated in the final rule.
93. Virginia League of Conservation Voters	We support the 28 million ton cap, a substantially stronger baseline that will result in immediate carbon reductions from power plants in 2020. Over the course of its 10-year span, from 2020 to 2030, this rule will result in approximately a 30% reduction in carbon emissions, which according to EPA's GHG Equivalencies Calculator is the same as taking 1.6 million cars off the road. This is an ambitious	Support for the proposal is appreciated.

	program and by far the largest step forward Virginia's taken to address climate change. We also recognize that carbon cap-and-trade programs are a long-term commitment and that this is the first phase of a much longer effort that we hope will result in a carbon-neutral electricity sector by 2050. While we understand the need for a statutory solution to formally join RGGI, and are supportive of such efforts, the regulation before the board is nonetheless an important step forward in the climate fight. We share concerns of the environmental community that this rule does not apply to facilities that burn biomass, which is also a carbon intensive fuel source. This is a limitation of the RGGI model altogether and one that can and should be dealt with under a future rulemaking here in Virginia aside from the regulation currently before this board. This criticism aside, we support Virginia's participation in the nation's most proven, effective, multi-state carbon market. Take for example the following facts from Acadia Center's 2017 report "Outpacing the Nation: RGGI's Environmental and Economic Success: --In 2016 RGGI states emitted 79,228,039 tons of CO_2, falling 8.4% below the RGGI cap, and emissions have fallen 40% since RGGI launched. --Average electricity prices across the region have decreased by 6.4% since RGGI took effect, while electricity prices in other states have increased by 6.2%. --Since RGGI launched member states have reduced emissions by 15% more than other states and experienced 4.3% more economic growth. --The RGGI states have proposed to strengthen the program through 2030, supporting the program's continued environmental and economic success. --Proposed RGGI reforms will result in 130 million fewer tons of CO_2 and	

	$1.28 billion in avoided health impacts. On top of these economic benefits, Abt Associates, in their 2017 study, "Analysis of the Public Health Impacts of the Regional Greenhouse Gas Initiative, 2009-2014," outlined the strong public health benefits of capping carbon emissions. They found RGGI had resulted in up to 830 lives saved, more than 8,200 asthma attacks avoided, and 39,000 lost work days averted due to reductions in harmful air pollution from power plants. Abt estimates the economic value of RGGI's health and productivity benefits at a cumulative $5.7 billion. By adopting this regulation, the board is setting Virginia on a trajectory to cleaner air, a healthier population, and increased innovation in the clean, renewable energy sector that will in turn drive our economy forward. At the same time, Virginia will be doing its part alongside the other RGGI states to cut carbon emissions and address climate change, even in an era of federal inaction on the largest environmental threat we've ever seen. The tide is turning in this fight, and Virginia is at the forefront. This important rule is for the good of clean air, public health and Virginia's economy.	
94. Virginia Manufacturers Association (VMA)	The original proposed rule included a CO_2 allowance budget of either 33 or 34 million tons. The re-proposal reduces the CO_2 allowance budget to 28 million tons. DEQ originally calculated significant cost increases to Dominion's customers. These cost projections estimated that costs to industrial customers would increase from 0.5% to 1.1 % annually. The chief assumptions made in this analysis were: 1. Natural gas prices would increase slightly; 2. Future demand would increase substantially; and 3. Some additional solar will be added, but not the 5,000 MW included in GTSA policy goals. These assumptions were derived from the	See the current response to current comment 89. The commenter is correct that the Analysis Group bill impacts analysis shows that bill impacts to customers are expected to be very small or even net positive after taking into account the allowance allocation approach that will return the value of 95% of the allowances to regulated entities for the benefit of customers. The commenter questions the assumption that auction revenues will be returned to regulated entities and that the revenue will inure to the benefit of customers. The rule provides that the allowances will be allocated to regulated entities and that the allowances cannot

	Dominion IRP in place at the time. Dominion is now in the process of revising its IRP, thus preventing the economic analysis of the re-proposed rule from using IRP assumptions. The original analysis assumed that any revenue from selling allowances in the RGGI market or to third parties will be returned to customers. It is important to distinguish this revenue from the flow back that regulated utilities will receive as reimbursement for the purchase of the consigned allowances. DEQ now analyzes a 28 million ton allowance budget scenario and predicts no cost increase for any Dominion customers. The DEQ cost analysis adopted by DEQ predicts no rate increases because it is based on indefensible assumptions. DEQ never explains why the original analysis was abandoned, except to state "things can change a lot in a year" and to "foster better integration into RGGI." Better integration into RGGI can only mean that RGGI wants fewer allowances auctioned in its market to minimize dilution and resulting allowance price decreases. The DEQ cost study assumes that: 1. The reimbursement of consignment auction costs will be passed to customers. 2. The policy goals in 2018 GTSA are in place by 2030: 5,000 MW of solar, 30 MW of battery storage, and $870 MM of spending on energy efficiency programs. 3. Renewable generation offsets generation from affected units. 4. Further reduction in natural gas prices. 5. Demand reductions because demand is down in other RGGI states. 6. 12-18% reductions in firm power price projections from the prices modeled in 2017. On the first point, there is nothing in the rule that requires cost flow back from the consignment auction to regulated utilities to flow down to customers. In fact, there is no mechanism in the rule for how the flow back to the regulated utilities will	be used for compliance purposes until they have been submitted to and purchased at auction. Because the allowances belong to the regulated entities the revenue from the sale of the allowances also belongs to regulated entities. In the normal course, regulated utilities subject to economic regulation by the SCC will be required to account for the value of the allowances in ratemaking cases. The comment acknowledges this flow of value. The commenter is correct that there is nothing in the rule that requires cost flow back to regulated utilities and then to consumers. That is because Virginia's regulated utilities are governed by the SCC, an independent state agency established by the Constitution of Virginia. In a regulated state such as Virginia, state law mandates the the electric utilities function in this manner. Furthermore, because SCC is a separate branch of government, there is no obligation for SCC to consult with DEQ. With respect to the modeling analysis that concludes that the emissions level in 2020 will be 28 million tons, see the current response to current comment 46. With respect to the SCC statements based on Dominion modeling, note that there are a number of issues in this analysis; see the current response to current comment 20. With respect to the specific statements about the SCC analysis: the SCC analysis was carried out by Dominion, and the Dominion modeling appears to use assumptions similar to those used by Dominion for its 2019 IRP—an analysis that was rejected by the SCC. The commenter makes several mistaken observations about the assumptions used in DEQ's IPM modeling, including: (1) DEQ does not assume gas prices will decrease from current levels, but rather uses the well-accepted projections of the federal Energy Information Administration AEO 2018; (2) DEQ uses the demand forecast of the regional transmission organization PJM in its analysis; and (3)

	work, let alone the flow down to the customers. Obviously, this assumption must be removed from the analysis. The removal of this assumption alone will result in a projection of substantial increased costs to industrial and residential consumers. These costs are significant to Virginia manufacturers. The SCC performed its own study and provided a summary of the study to Delegate Kilgore and VMA. The SCC does make DEQ's assumption of full implementation of the GTSA policy goals of 5,000 MW of solar, 30 MW of battery storage and $870 million spending on energy efficiency programs. The SCC analysis does not assume the flow back of consignment auction costs to customers. The SCC testified before a subcommittee of the Virginia House Labor and Commerce Committee, on January 24, 2019, that the flow back will be returned to customers "one way or another ultimately," but this assumes that in a future rate proceeding before the SCC, the flow back will be credited to customers. There is no basis to predict whether, how or when this will happen. The SCC concludes that the total cost to Dominion from 2020-2030 will increase $3.3 billion if only linked to RGGI and $5.9 billion if Virginia joins RGGI. Experience informs our members that a substantial portion of these increased costs will be passed to industrial customers. DEQ must adopt the SCC analysis. Areas of difference are mainly, that: 1. Even if the full GTSA policy goals are implemented, renewables will not necessarily offset generation from Virginia fossil fuel units. Virginia is a member of PJM, which dispatches units over a large region. Additional renewables are likely to displace older, higher cost units in other states. 2. These renewables and fossil fuel units are two different types of generation and are not interchangeable. Solar is intermittent,	DEQ assumes nothing about the allowance prices and power prices—these are outputs of the IPM model. The IPM model is a well-accepted tool used by utilities (including those operating in Virginia). The commenter incorrectly states that DEQ never explained why the 28 million ton cap was proposed. DEQ discussed its reasoning in great detail; see, for example, the initial response to initial comment 37. The revised cap was the result of modeling and forecasting exercises undertaken by a variety of parties, including DEQ, after the original caps were proposed using updated data. These data are readily publically available. The commenter is mistaken that the record is incomplete. DEQ has met every requirement of the Administrative Process Act in a transparent process to explain the development of the regulation. The fact that the commenter disagrees with the agency's analysis and supporting documentation does not render the regulatory action improper.

	and fossil fuel is continuous. 3. The DEQ analysis assumes that natural gas prices will decrease below the very low current prices. DEQ only cites general EIA analyses over decades to support this assumption. The DEQ analysis assumes demand will reduce in Virginia because demand is down in other RGGI states. No Virginia demand analysis is made. Demand in RGGI states appears to decrease because RGGI raised the cost of generation, and electricity is now imported into these states. 5. The DEQ analysis also assumes that firm power price projections from the prices modeled in 2017 will drop 12% to 28% from 2020 to 2030. No explanation supporting this assumption is given. SCC provided a detailed analysis of the DEQ cost analysis, and found DEQ's conclusion that there would be no rate impact to be completely incorrect. SCC concluded that the costs to Dominion will be $3.3 billion if Virginia only links (e.g., consignment) to RGGI. If Virginia joins RGGI, the cost will be $5.9 billion. SCC finds that the most significant mistake that DEQ makes is to misunderstand Dominion Energy's operation and rate structure. DEQ's analysis treats Dominion as only a buyer of electricity and effectively a merchant company with only shareholders to bear costs. In doing so, DEQ ignores the fact that Dominion is an integrated utility, with substantial generation to serve customer load. Obviously, the allowance structure is designed to increase the cost of generation by reducing allowance allocations by 3% a year. Customers will pay for the increased operating costs for fossil fuel units to continue to run. Furthermore, these costs will be borne by the customers whether the units run or not. None of these costs are included in the DEQ analysis. SCC models show that Chesterfield Units 5 and 6 and Clover Units 1 and 2 will be forced to retire prematurely	

	(2022 and 2025, respectively). Dominion's customers will pay for the retired units and will also pay for the construction of 1,500 MW that must be built earlier than anticipated to replace the retired units and meet PJM capacity requirements. Thus, Virginia customers effectively pay twice for the same 1,500 MW of generation. As noted above, even if GTSA policy goals are achieved, Dominion will not meet its CO_2 emissions reduction goals. The additional renewables, battery capacity and efficiency projects will displace the least efficient, highest cost units in PJM. These are not Dominion units. Dominion is still likely to have to prematurely retire 1,500 MW of coal and replace those MW with natural gas to meet PJM's capacity needs. DEQ also modeled a CO_2 emissions allowance price that is lower than the ECR trigger price. The rule and the RGGI market establish the ECR trigger price to act as the market floor for allowance prices. If the allowance price drops below the ECR trigger price, then allowances are removed from the market until the price moves up. DEQ's allowance cost assumption that the CO_2 emissions allowances will always clear at a price lower than the ECR trigger price requires explanation, as the ECR mechanism in the RGGI model rule and incorporated in the proposal is designed to prevent this pricing assumption from happening. In its analysis, DEQ assumed a 2.1% discount rate. SCC assumed 6.31 % discount rate, which reflects Dominion Energy's after tax weighted average cost of capital. DEQ's use of the lower discount rate understates the true costs of future capital investments. SCC's use of the 6.31% discount rate reflects Dominion's actual cost of funding large capital projects. Again, DEQ makes a fundamentally flawed assumption that understates the	

	actual cost of the rule. None of these DEQ assumptions are supported by actual analysis of the Virginia energy landscape, and DEQ does not attempt to provide any insight. At this point, the record is incomplete, because the actual cost impact of the rule is not included. The fact that the DEQ analysis did not capture any of these costs, more than demonstrates that it cannot be the basis for the rule. DEQ must withdraw the rule and adopt the SCC cost analysis. Without accurate cost data, an accurate cost-benefit analysis cannot be made. The public is denied the right to notice and comment on the rule. Making false assumptions to achieve an inaccurate cost impact is unacceptable and skirts the Joint Legislative Audit & Review Commission review process. Only re-issuing the proposal with an accurate cost analysis will meet notice and comment requirements and allow the board to make an informed decision.	
95. VMA	The proposal revises the definition of "fossil fuel-fired CO_2 budget source" to change the amount of fuel comprised of fossil fuel from 10% to 5%. This revision places manufacturing plants at risk of becoming subject to the rule without any CO_2 allowance allocations. VMA urges DEQ to retain the 10% fossil fuel combustion threshold. Non-fossil fired fuel units require some amount of fossil fuel as a backup fuel and for periods of startup, shutdown, and for flame stability. These units are traditionally operated well below 10% fossil fuel. However, they do typically vary from year-to-year in the 3-7% range. By lowering the threshold to 5%, DEQ could be creating a situation where units might be subject to the standards one year and not another. Retaining the 10% fossil fuel combustion in this definition is essential to keep operational flexibility intact for these units and not unnecessarily creating confusion over applicability to the rule. The proposal must allow more flexibility for com busting other environmentally-friendly fuels, while continuing to retain the	Reducing the fossil fuel threshold from 10% to 5% is needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program. See the current response to current comment 90 for more information on the applicability of the rule to new industrial facilities. The industrial exemption has been designed to clearly exempt certain facilities from the regulation. A regulation only describes facilities to which the regulation applies, not everything to which it does not apply. By extension, an exemption can only be offered if the defined regulatory entity is subject to the regulation in the first place. As discussed in current response to current comments 24 and 40, the applicability of the rule to fossil fuel-fired facilities has been clarified. See the current response to current comment 105 regarding fees.

	industrial exemption for those units. VMA sees the proposal as overly restricting manufacturing growth in Virginia. As VMA articulated in its original comments, Virginia has a $112.3 billion economic output from its robust manufacturing sector and has prospered from a strong competitive position. Our original comments focused on the damage to that position due to the increase in electricity costs expected from a cap and trade rule. The re-proposal goes much further. It overtly clips Virginia's upward trajectory by forcing new manufacturing sources to comply with this CO_2 cap and trade rule. Specifically, the proposal diverges from the original rule by providing that the exemption only applies to sources that meet the exemption requirements prior to January 1, 2019. The re-proposed rule grandfathers existing sources, but any new facility will have to contend with the CO_2 cap and trade rule. The result of further narrowing the exemption is clear. New manufacturers will choose to locate facilities requiring an electric generating unit greater than 25 MWe in another state. A decline in manufacturing has already been measured in other RGGI states. The decline in manufacturing in RGGI states can be seen by comparing the industrial electricity demand. RGGI states' demand fell 17% in comparison with non-RGGI comparison states that fell only 3%. Although CO_2 may be reduced locally by having fewer manufacturing sources in the RGGI states, those CO_2 emissions are simply occurring in non-RGGI states. This is not the solution to global CO_2 emissions. The damage to the manufacturing sector is tangible. The Virginia Economic Development Partnership provides "cost of doing business" as a primary consideration for businesses looking to enter the state. That cost is composed of the cost of electricity, to be impacted by the rule, as well as the cost of compliance. The rule will	

	cause industry members considering a Virginia siting to choose less expensive siting choices outside of Virginia. Putting Virginia at a competitive disadvantage for attracting larger manufacturers is completely contrary to the goals of the Governor to bring more manufacturers to Virginia, increase jobs, and enhance the economy. For these reasons, VMA strongly advocates for the removal of the January 1, 2019 grandfathering clause from the industrial exemption. All manufacturers, regardless of when they come to Virginia, should be able to use the exemption. We believe that the exemption is intended by DEQ to apply on a facility basis given that the exemption refers to exempting any "CO_2 budget source located at or adjacent to and physically interconnected with a manufacturing facility." The rule defines a "CO_2 budget source" as "one or more budget units," contemplating that a source can include more than one unit. However, since the term CO_2 budget source is used in multiple contexts throughout the rule, clarification is needed to ensure the exemption's consistent application. We recommend that the exemption substitute "source" for "CO_2 budget source" because "source" is defined in the proposal as "a source with multiple units." The exemption provides a calculation to determine annual net electrical generation. The exemption does not apply when a source supplies more than 10% of its annual net electrical generation to the electric grid. That calculation in the exemption should be clarified to note that the sales, purchases, and generation should be expressed in MW. The exemption also requires that the source supply less than 15% of its annual total useful energy to another entity. "Total useful energy" is defined as "the sum of gross electrical generation and useful net thermal energy." We	

	recommend that the definition of "total useful energy" and "useful net thermal energy" also be expressed in megawatts for consistency. We suggest that exemption applicability should be determined on an annual basis at the end of the calendar year to dictate applicability for the following calendar year. For example, if an industrial source exceeds the 10% annual net electrical generation to the electric grid requirement, as determined using data from January 1 to December 31, then that source would not retain the exemption for the next calendar year. Given that the proposal does not provide allowances for non-fossil fuel CO_2 emissions, the proposal should clarify that these emissions are excluded. Treatment of CO_2 emissions from biogenic sources should not depart from federal and internationally accepted accounting protocols. The changes to the definition of "CO_2 allowance" should be reversed. Previously, the definition of CO_2 allowance included a clarification that the allowance is an authorization "to emit up to one ton of CO_2 that has been generated as a result of combusting fossil fuel .. . " The underlined phrase should be re-inserted into this definition to clarify that the re-proposal does not require that allowances must be obtained for CO_2 emissions from non-fossil fuels. Any redundancy perceived in making this change is outweighed by the risk of different regulatory interpretations on this important point. The language in the industrial exemption requires qualifying facilities to obtain a permit. Since this is an exemption to the regulation that DEQ wants to include in facility operating permits, DEQ should ensure that the facility is not required to pay the permit modification fee for such inclusion. DEQ could elect to incorporate this language as an administrative change. Further, DEQ	

	should provide some guidance to facilities as to how it intends to facilitate inclusion of this language into existing permits.	
96. VMA	The rule includes a number of provisions from the RGGI model rule but does not provide adequate detail on how the auction will work in Virginia. Although many revisions to original proposed rule supposedly better reflect the provisions of the RGGI model rule, they do not clarify how RGGI will run the auction and integrate with participants and customers. Among the missing details are: How the CO_2 allowances will be consigned and auctioned? How will the reimbursement of consigned allowance auction costs be returned to regulated entities? Will the reimbursed consigned allowance auction costs flow down to customers? If so, how? How will auction prices be set? Will there be a mechanism for sales of excess allowance to third parties? These omissions are not de minimis. Failure to provide these details violates the APA because, without these details, there can be no real opportunity for notice and comment. This fact is reinforced by comments filed by RGGI making the same observation. It is arbitrary and capricious to not include the actual requirements of the rule in the proposed rule. The lack of the opportunity for notice and comment cannot be cured through guidance or by a cross-reference. DEQ must withdraw the rule and revise it to provide adequate detail to allow the regulated community to adequately comment.	Details as to how the specifics of the auction will operate will be addressed in auction "instructions" which are developed separately from the regulation. DEQ will take the commenter's concerns into account when those instructions are developed. DEQ believes that most of these issues are described within the regulation or are self evident, for example, the fact the reimbursed consigned allowance auction costs flow down to customers in accordance with the SCC and the applicable state code.
97. VMA	Without any basis, the board departed from the RGGI 2017 Model Rule by committing Virginia's program to continued reductions in CO_2 allowances from 2030 "and each year thereafter." This has no legal or practical basis and further, it is unclear whether further reductions in CO_2 allowances and, therefore, in the state budget cap, will be necessary in 2031. The RGGI states have already provided comments that disapprove of	As discussed in the current response to current comment 54, the proposal has been modified to return to consistency with the RGGI Model Rule.

	this inconsistency. RGGI has an interest in the full compatibility of Virginia's program design with the other RGGI states. To address future caps, RGGI has set forth a periodic RGGI program review process for the participating states to consider the appropriate future trajectories by consensus. Even though VMA strongly disapproves of Virginia's steps to enter the RGGI program, if Virginia pursues this path, Virginia's plan should be compatible with the RGGI model rule.	
98. VMA	DEQ bases its authority to adopt a CO_2 cap and trade program upon an Attorney General opinion. This opinion actually provides DEQ with no authority to issue the rule. The basis of the opinion is that CO_2 fits within the definition of "air pollution" under Virginia law and regulations. The opinion assumes that because the board has the authority to regulate air pollutants, it can legally adopt this rule, which significantly reduces CO_2 emissions through a Virginia market-based program linked to RGGI. The opinion bases its opinion that CO_2 is an air pollutant, which the board has the authority to regulate, on two arguments. First, the opinion states that GHG, which include CO_2, are currently regulated by the Clean Air Act's PSD program, which is administrated by the board. Second, it opines that there is a "growing consensus" among scientists that CO_2 contributes to elevated global temperatures that maybe harmful to the welfare of people, animals, and property. The PSD program does not provide the board with the authority to regulate CO_2. In 2014, the U.S. Supreme Court held in UARG v. EPA, that neither EPA nor states have authority under the NAAQS to regulate CO_2. Likewise, the UARG v. EPA decision held that CO_2 is not a pollutant that can be regulated alone under the PSD program. The decision found that CO_2 cannot be regulated under the NAAQS because it has potential global impacts, not state impacts. The NAAQS are	DEQ notified the appropriate legislative committees of this regulatory action in accordance with § 10.1-1308 in November 2017. To state that the board can only regulate air pollutants subject to NAAQS and specific emissions limits is inaccurate. The source of the board's authority, the State Air Pollution Control Law (§ 10.1-1300 et seq.) is broad, and apart from numerous non-NAAQS Clean Air Act pollutants, the board may also promulgate regulations in the absence of a specific federal requirement to address a state-specific need. This is demonstrated by, for example, the board's air toxics and odor regulations. Greenhouse gases are not covered by a NAAQS but they are covered in other areas of the federal Clean Air Act and other existing board regulations. The proposed ACE would impose certain GHG requirements on coal plants, including an hourly NSR applicability trigger. ACE is not an emissions trading program, and it is unlikely that it will conflict with existing emissions trading programs. The ACE rule has not been finalized, may or may not be issued, and may or may not withstand legal scrutiny; under the circumstances it is not appropriate for the board to consider ACE in the context of this regulatory action.

	administered on a state-by-state basis. The UARG decision nullifies the opinion and the board's authority to issue the rule. The board's own regulations extend the application of the UARG decision (9VAC5-10-20). The board can only regulate air pollutants subject to NAAQS and specific emissions limits. A CO_2 cap and trade program is neither part of Virginia's NAAQS program or a specific emissions limit. § 10.1-1308 still limits DEQ's ability to issue any regulations more stringent than federal requirements without providing notice to the appropriate standing committee of the General Assembly. No such notice has been made. While at this point EPA is not directly regulating CO_2 emissions, the Affordable Clean Energy Rule (ACE) will regulate CO_2 under § 111(d). Once ACE is issued, § 10.1-1308 will clearly apply to the rule, and notice requirements must be satisfied.	
99. William L. Hodges, Chairman, Board of Supervisors, King William County	I am writing to provide comments to DEQ and the board in opposition to the re-proposed regulation. I have previously submitted comments and would ask that they be incorporated by reference. As a resident of King William County and the Chairman of the Board of Supervisors, I can attend to the critical importance of the West Point Paper Mill to our county. The Mill is one of the largest employers, one of the largest taxpayers, and one of the most significant corporate members of our community. The hundreds of jobs that the mill provides, the hundreds more that it supports, and the millions of dollars that it injects into the local economy are irreplaceable. With that in mind, I oppose the re-proposed regulation because it does not exempt emissions from biomass, which is widely considered to be a carbon-neutral fuel source and is the lifeblood of the West Point mill. While DEQ states that the rule is designed to address CO_2 emissions from fossil fuel combustion, the rule as it is currently written would go well beyond that and regulate CO_2 emissions from non-fossil sources	The commenter's concerns are well taken. The cap-and-trade program has been designed to meet the goal of reducing carbon pollution--which will be beneficial to the manufacturing sector--while protecting the economy. Industrial generation (current comment 28) and biomass (current comments 24 and 40) are discussed in greater detail elsewhere.

	when those sources are co-fired with fossil fuels. The board should adopt language that specifically and clearly exempts non-fossil fuel sources from the regulation. Further, I would encourage the board to extend the exemption for industrial generation to new facilities. Should the exemption apply only to existing facilities, the board should adopt any language necessary to clarify that the exemption applies at the facility level (rather than to individual boilers) to allow facilities to conduct proper maintenance and grow.	
100. Jonathan A. Lanford, County Administrator, Alleghany County	I on behalf of the Alleghany County Board of Supervisors in opposition to the re-proposed rule. The West Rock Paper Mill in Covington is a significant economic driver for our community, providing over 1100 jobs and supporting over $200,000,000 in local investment through supplier purchases, payroll, and taxes every year. If care is not taken, the proposal could have a serious and negative impact on the mill. One of our chief concerns is the treatment of energy from biomass, which is critical to the mill's operation. Unfortunately, despite the rule's nominal focus on fossil fuel emissions, the current language would apply to biomass (and other non-fossil fuel sources) when they are co-fired with fossil fuels. Biomass is widely considered to be a carbon-neutral fuel source, and this fact is not changed when biomass is co-fired. Moreover, by including non-fossil fuel sources, the regulation would greatly exceed its stated scope. Accordingly, we are opposed to the rule as currently drafted and encourage DEQ to correct this issue by including in the rule a clear and specific exemption for CO_2 emissions from non-fossil fuel sources, such as biomass.	The commenter's concerns are well taken. The cap-and-trade program has been designed to meet the goal of reducing carbon pollution--which will be beneficial to the manufacturing sector--while protecting the economy. Industrial generation (current comment 28) and biomass (current comments 24 and 40) are discussed in greater detail elsewhere.
101. About 200 sponsored letters	I am writing to provide comments in opposition to the re-proposed regulation for the CO_2 Budget Trading Program. I work at a WestRock Mill which has been in operation for over 100 years. The Mill is the economic backbone of our community, supporting over 1000 jobs and	The commenters' concerns are well taken; please see the current response to current comment 99.

	injecting hundreds of millions of dollars a year into our local economy. I am concerned that the regulation, and specifically the treatment of biomass, could have a serious and negative impact on the mill. DEQ has said that the intent of the rule is to focus on fossil fuels, but as written, it would apply to biomass (and other non-fossil fuel sources) when they are co-fired with fossil fuels. Biomass is a carbon-neutral fuel source, and it should not be included in a rule designed to deal with fossil fuels. With that in mind, the rule should be amended to specifically exclude non-fossil fuel emissions. Additionally, the exemption for industrial facilities should not be restricted to existing facilities. If the restriction remains, the rule should have language that clearly allows for exempted facilities to conduct maintenance and upgrades without losing their exemption.	
102. Richard Watro, Vice President, Covington Operations, WestRock	On behalf of the nearly 1,100 employees of WestRock's Covington paper mill, I appreciate the opportunity to provide comments. In addition to the jobs the mill provides, and the hundreds more it supports, the mill contributes over $270,000,000 to Virginia's economy through local purchases, and roughly $11,000,000 in property and sales tax payments every year. The products we make at Covington are exported around the world, primarily through the Port of Virginia. Papermaking is an energy-intensive process, and the mill produces a significant portion of its own power, primarily through the use of renewable biomass. The proposal should be amended to treat all biomass as carbon-neutral so long as carbon stocks are stable or increasing. The use of biomass is recognized as carbon-neutral by well-supported science, regardless of whether or not it is co-fired with a fossil fuel source. The failure to recognize our primary fuel source as carbon neutral would deviate from the practice of other states that participate in RGGI, as well as widely accepted	The commenter's concerns are well taken; please see the current response to current comment 99. The cap-and-trade program has been designed to meet the goal of reducing carbon pollution--which will be beneficial to the manufacturing sector--while protecting the economy.

	international carbon accounting protocols, and could have negative long-term consequences. The regulation consistently has been aimed at reducing GHG emissions from only "fossil fuel" combustion like all other RGGI states. We recommend that regardless of how "fossil-fuel fired" is defined, and whether a unit co-fires biomass with fossil fuel, the regulation should be explicit in that allowances are only required for emissions from the combustion of fossil fuel and that none are required for emissions from combustion of biomass fuel. This change will provide necessary clarity and prevent unintended consequences that might result from a misinterpretation. In light of the competitive disadvantage that Virginia industrial facilities would face if they were subject to the regulation, it should clearly exempt those facilities. Our facilities are subject to Clean Air Act and other federal and state regulatory programs which impose stringent standards and permitting requirements. Those costly investments have dramatically reduced emissions and we often exceed the standard requirements. While the regulation includes an exemption for certain existing industrial facilities, it only applies to units in service as of 2019. That limitation should be removed, as there is no reason that new industrial facilities should subject to the adverse economic impact of having to obtain allowances for their emissions. Again, this would put those facilities at a serious competitive disadvantage and will make it much more difficult to attract new investments to the state. If the limitation is retained, the regulation should be clear that any modifications or replacements of machinery and equipment do not cause the facility to lose the exemption.	
103. WestRock	The rule changes do not address our	DEQ believes that the biomass

	primary concern, which is that the regulation undermines internationally accepted principles of carbon accounting and in some cases regulates emissions from non-fossil fuels when they are co-fired with fossil fuels. As stated in our comments on the original proposal, emissions from non-fossil fuels, particularly those that are renewable and biogenic like biomass, should be unequivocally exempted from this rulemaking. DEQ has requested comments on whether and how the current language of the proposed rule should apply to "CO_2 emissions from CO_2 budget units that do not combust fossil fuels exclusively." In the re-proposed rule, DEQ has altered the definition of "fossil fuel fired" to lower the threshold of fossil fuel from 10% of fuels combusted to 5%, the revised rule is even more likely to include non-fossil (including renewable biomass) fuel emissions. The following language should be reinserted in the final rule to ensure that the re-proposed rule so that the final regulation does not exceed the scope established by RGGI: "The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances <u>from the combustion of fossil fuel</u> available for compliance deductions under 9VAC5-140-6260, . . . " Further, DEQ should revise the definition of "CO_2 Budget Source" to reinsert the phrase "that has been generated as a result of combusting fossil fuel" and clarify the applicability of CO_2 allowances for emissions resulting from fossil fuels. In summary, the proposed definitions of "fossil fuel fired" or "CO_2 allowance" clearly exclude CO_2 emissions from non-fossil sources from regulation, and we strongly urge DEQ to amend the regulation to ensure it remains consistent with the fossil-fuel focus of EO 11 and the rulemaking process to date.	applicability has been properly addressed; see current responses to current comments 24 and 40.
104. WestRock	The re-proposed rule states that if biomass (or some other non-fossil fuel) comprises a threshold percentage of the total heat input into	DEQ believes that the biomass applicability has been properly addressed; see current responses to current comments 24 and 40.

	an electric generating unit, the unit and its biogenic CO_2 emissions are not regulated. However, if biomass comprises less than a threshold percentage, biogenic CO_2 emissions are regulated, and a facility must remit allowances for all CO_2 emissions from that unit. This treatment of biogenic CO_2 emissions is arbitrary and capricious. Biomass carbon neutrality does not change based on the amount of biomass fired, nor does it change when biomass is co-fired with other fuels. The rule's treatment of CO_2 emissions from the combustion of biomass represents a significant departure from current U.S. federal law, internationally-accepted carbon accounting protocols, and the existing RGGI model rule. Moreover, by regulating CO_2 emissions from biomass, the regulation exceeds the stated scope of the RGGI Rule, which is specifically intended to "Reduce and Cap Carbon Dioxide from Fossil Fuel Fired Electric Generating Units."	
105. WestRock	The intent of the re-proposed rule is to regulate emissions of fossil fuels from utility electric generating units. We appreciate DEQ's efforts to clarify that manufacturing facilities are exempt from regulation and offer three suggestions for ensuring that § 6040 B of the re-proposed rule clearly exempts industrial facilities that generate steam and electricity. First, we propose that the reference to "CO_2 budget source" be removed and the first segment of this language refer to "source." Removal of this language offers more clarity to manufacturers as it more clearly distinguishes between those facilities impacted by the rule and those that are not. We also recommend that the definition of CO_2 budget source be amended for consistency to read: "'CO_2 budget source" [except as exempted in 9VAC5-140-6040 B] means a source that includes one or more CO_2 budget units." This language would further clarify how facilities that qualify for this exemption are affected under the rule.	Support for the proposal is appreciated. See the current response to current comment 12 for more information on details related to applicability. More information on the applicability of new sources is available in the current response to current comment 90. See the current response to current comment 90 for more information on the applicability of the rule to new industrial facilities. Exemptions are allowed throughout the board's regulations, and, as necessary, permits must be modified in order for a facility to claim the exemption and then demonstrate compliance with the exemption's requirements. These permit modifications cost money to develop and implement. There is no reason to treat facilities that are meeting the requirements of this regulation to be treated any differently from any other permitted facility.

	Second, the language dealing with the industrial exemption should extend to facilities regardless of the date they commenced operation; megawatt units of measure should be included with respect to the sales, purchases, and generation; and permitting requirements should be clarified to ensure that the facility is not required to pay a permit modification fee. Further, DEQ should provide guidance to facilities as to how it intends to facilitate inclusion of this language into existing permits. Overall, WestRock supports the concept of net electrical generation. We recognize that many manufacturers generate and consume electricity on site, but also are able to sell a portion to the grid. In addition to the specific recommendations offered above, we support higher thresholds for net electrical generation and total useful energy due to the benefits that CHP offer. Third, we request that DEQ remove the reference to "CO_2 budget source" and retain "source" to be consistent with our previous recommendation. Since this is an exemption to the regulation that DEQ wants to include in a facility's operating permit, DEQ must ensure that the facility is not required to pay the permit modification fee for such inclusion. DEQ could incorporate this language as an administrative change. DEQ should provide guidance to facilities as to how it intends to facilitate inclusion of this language into existing permits. We also support the incorporation of the proposed the industrial exemption as it applies on a facility basis and not to individual emission units. As such, modifications or newly constructed units at an exempt facility would be exempt as long as the facility still qualifies for the exemption.	
106. The Windaction Group	I have tracked the electricity market in the RGGI states closely since the program's inception. Claims that	The comment suggests that the emissions reductions accomplished in the power sector in the RGGI region are

	RGGI is responsible for precipitous declines in carbon emissions while saving consumers in energy costs, creating new jobs, and enhancing public health, are simply not accurate according to RGGI's own numbers. Citing from the September 2018 report by RGGI (The Investment of RGGI Proceeds in 2016), RGGI allowances cost electricity consumers over $2.65 billion in the period from 2008 to 2016 to be spent on programs meant to reduce carbon emissions. Of these funds, the states seized $93.1 million to meet budget shortfalls, allocated $245.1 million for future programs and "invested" $2.17 billion in projects that by 2016 reportedly trained 8,150 workers and promised a lifetime reduction in carbon of just 27.8 million short tons. In the same period, the free market reduced electric sector carbon emissions in the RGGI states by 49 million short tons--2 times the claimed lifetime reduction RGGI touted--and at no additional cost to ratepayers. In other words, by 2016 the free market had already exceeded the claimed lifetime reduction in carbon emissions documented by RGGI. With regard to cost per ton, the numbers are worse. From 2008 to the end of 2016, the clearing price for RGGI allowances averaged $3.03 per ton. At the highest, the allowances reached $7.50 in December 2015 before tumbling to $3.55 per ton at the end of 2016. In the most recent auction held in December 2018, allowances cleared at $5.35. Yet, state regulators approved investing $2.17 billion to lower emissions by just 27.8 million short tons which equates to $78 per ton. In other words, RGGI sold allowances for well under $10/ton and then RGGI states built offset projects costing $78/ton. On specific projects, the cost per allowance was often much higher. RGGI proponents are asking the public to believe that the program is delivering on a global environmental promise, but the reality is that it is a colossal failure of resource allocation that should be	attributable to market forces and not to the RGGI program, but the comment provides no evidence or analysis to support this assertion. Based on data from the U.S. Energy Information Administration, power sector emissions in 2016 in the RGGI region were approximately 50% lower than they were in 2005, while in the U.S. as a whole, power sector emissions were only 25% lower than they were in 2005 (EIA 2018). This suggests that the RGGI program and other actions by and in the RGGI region have succeeded in reducing emissions beyond what the market would have accomplished on its own. Also note that an independent team of economists at Duke University analyzed the factors contributing to emissions reductions in the RGGI region and concluded that the RGGI program was responsible for at least half of the emissions reductions achieved in the region This evidence would seem to directly contradict commenter's assertions that market forces alone achieved the reductions. The comment also suggests that RGGI has "extracted billions from ratepayers" without explaining the math that led the commenter to this conclusion. The Analysis Group has conducted 3 independent and comprehensive economic impact analyses of the RGGI program since RGGI's inception in 2009. The reports can be found here: https://www.rggiprojectseries.org/reports. Together, the reports conclude that RGGI has resulted in net economic benefits to the region of approximately $4 billion from 2009 to 2017. Here, "net economic benefits" refers to the benefits after the costs of the program were taken into account. These independent analyses would seem to contradict the comment's assertions. In Virginia, allowances are to be allocated to the entities that have a compliance obligation under the program. These entities will submit the allowance to a consignment auction and will receive the proceeds from the auction for the benefit of their customers. In effect, the value of the allowances will be used to offset the

	repealed to leave more efficient market forces. There are far more productive options for lowering emissions that do not involve extracting billions from ratepayers. I encourage Virginia to look past ideology behind RGGI and look at the numbers.	cost of the program. In its bill impacts analysis, the Analysis Group concluded that the program would result in a small net benefit to consumers in Virginia.

Detail of Changes Made Since the Previous Stage

*Please list all changes that made to the text since the previous stage was published in the Virginia Register of Regulations and the rationale for the changes. Explain the new requirements and what they mean rather than merely quoting the text of the regulation. * Please put an asterisk next to any substantive changes.*

Changes made after the original proposal:

Current chapter-section number	New chapter-section number, if applicable	New requirement from previous stage	Updated new requirement since previous stage	Change, intent, rationale, and likely impact of updated requirements
None	Article 1	CO_2 Budget Trading Program General Provisions	--	--
None	9VAC5-140-6010	Purpose	Amended to state that the rule is to be effected in a manner protective of health and the environment.	Needed for clarity.
None	9VAC5-140-6020 C	Definition of "allocate"	Amended to reflect relocation and renumbering of DMME provisions (see 9VAC5-140-6211).	Needed for clarity.
None	9VAC5-140-6020 C	Definition of "allowance"	Deleted.	Replaced with the new term "CO_2 allowance." Needed to ensure the proper functioning of the RGGI allowance market.
None	9VAC5-140-6020 C	Definition of "alternate CO_2 authorized account representative"	Deleted.	Needed in order to be consistent with new RGGI terminology.
None	9VAC5-140-6020 C	Definition of "CO_2 allowance"	Added.	Replacing "allowance." Needed to ensure the proper functioning of the RGGI allowance market
None	9VAC5-140-6020 C	Definition of "CO_2 authorized alternate account	Added.	Needed in order to be consistent with new RGGI terminology.

		representative"		
None	9VAC5-140-6020 C	Definition of "CO_2 Budget Trading Program"	Amended.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "CCR allowance"	Amended to indicate that the CCR allowance is conditional.	Needed for clarity.
None	9VAC5-140-6020 C	Definition of "CO_2 CCR trigger price"	Amended to include the correct prices.	Needed in order for the program to operate properly.
None	9VAC5-140-6020 C	Definition of "CO_2 ECR trigger price"	Amended to include the correct prices.	Needed in order for the program to operate properly.
None	9VAC5-140-6020 C	Definition of "CO_2 offset allowance"	Added.	Needed in order for offsets from other states to be recognized.
None	9VAC5-140-6020 C	Definition of "conditional allowance"	Amended to clarify the relationship between a conditional allowance and a CO_2 allowance.	Needed in order for the program to operate properly.
None	9VAC5-140-6020 C	Definition of "conditional CCR allowance"	Added.	Needed for clarity and in order for the program to operate properly.
None	9VAC5-140-6020 C	Definition of "consignment auction"	Amended to refer to the correct auction entity.	Needed for clarity.
None	9VAC5-140-6020 C	*Definition of "fossil fuel-fired"	Amended to change the amount of fuel comprised of fossil fuel from 10% to 5%.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "maximum design heat input"	Deleted.	This term is not used in the proposal and must be removed.
None	9VAC5-140-6020 C	Definition of "minimum reserve price"	Amended to change the price from $2.00 to $2.32.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "receive"	Amended to be more specific.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "RGGI, Inc."	Deleted.	Needed for consistency with the RGGI Model Rule and to ensure Virginia's ability to participate in the program.
None	9VAC5-140-6020 C	Definition of "state"	Deleted.	Needed in order for clarity. "Participating state"

				replaces this more general term.
None	9VAC5-140-6020 C	*Definition of "total useful energy"	Added.	Needed in order for the industrial exemption (9VAC5-140-6040 B) to operate properly.
None	9VAC5-140-6020 C	*Definition of "useful net thermal energy"	Added.	Needed in order for the industrial exemption (9VAC5-140-6040 B) to operate properly.
None	9VAC5-140-6030	Measurements, abbreviations and acronyms.	Unused terms removed.	Needed for clarity.
None	9VAC5-140-6040 B	*Applicability.	Amended to clarify industrial facilities exempt from the rule.	Needed to address third-party industrial suppliers while maintaining consistency with the RGGI Model Rule.
None	9VAC5-140-6050 C 1	CO_2 requirements, holding allowances for compliance		The department sought comment on whether an amendment is needed to 9VAC5-140-6050 C 1 to specify that the total CO_2 emissions related to CO_2 allowances only includes emissions resulting from the combustion of fossil fuel.
None	Article 2	CO_2 Authorized Account Representative for CO_2 Budget Sources.	--	--
None	9VAC5-140-6090	Alternate CO_2 authorized account representative.	The term "alternate CO_2 authorized account representative" is amended to "CO_2 authorized alternate account representative."	Needed in order to be consistent with new RGGI terminology.
None	9VAC5-140-6100	Changing the CO_2 authorized account representatives and the alternate CO_2 authorized account representative; changes in the owners and operators.	The term "alternate CO_2 authorized account representative" is amended to "CO_2 authorized alternate account representative."	Needed in order to be consistent with new RGGI terminology.
None	9VAC5-140-6110	Account certificate of representation.	The term "alternate CO_2 authorized account representative" is amended to "CO_2	Needed in order to be consistent with new RGGI terminology.

			authorized alternate account representative."	
None	9VAC5-140-6130	Delegation by CO_2 authorized account representative and alternate CO_2 authorized account representative.	The term "alternate CO_2 authorized account representative" is amended to "CO_2 authorized alternate account representative." In subsection H, "must" has been changed to "shall."	Needed in order to be consistent with new RGGI terminology, and to reflect correct regulatory style.
None	Article 5	CO_2 Allowance Allocations	--	--
None	9VAC5-140-6190 A	*Base budgets.	The initial CO_2 base budget has been set at 28 million tons, declining by 3% per year through 2030.	Needed in order to realize the program goal of reducing carbon pollution at a certain rate of a specified time period.
None	9VAC5-140-6190 C	*Base budgets.	Amended to establish specific post-2030 adjustments.	Needed to ensure continuing compliance into the future.
None	9VAC5-140-6200	Undistributed and unsold CO_2 allowances.	Amended to correct the term "conditional allowance" and to replace "may" with "will."	Needed for clarity and in order for the program to operate properly.
None	9VAC5-140-6210 A	CO_2 allowance allocations.	Amended to clarify the allocation of allowances.	Needed for clarity.
None	9VAC5-140-6210 B	CO_2 allowance allocations.	DMME provisions have been moved to a separate new section (9VAC5-140-6211); succeeding sections renumbered accordingly.	Needed for clarity.
None	9VAC5-140-6210 ~~D~~ C	*CO_2 allowance allocations.	Amended to more clearly explain how the CCR allowances will be allocated, including a new equation for calculating the pro rata distribution of CCR allowances.	Needed for clarity and in order for the program to operate properly.
None	9VAC5-140-6210 ~~E~~ D	CO_2 allowance allocations.	Amended to more clearly explain how the ECR allowances will be allocated.	Needed for clarity and in order for the program to operate properly.
None	9VAC5-140-6210 ~~F~~ E	CO_2 allowance allocations.	Minor corrections.	Needed for clarity.
None	9VAC5-140-	CO_2 allowance	Timing requirements	Needed for clarity.

	6210 ~~I~~ H	allocations.	amended in order to provide more detail as to how and when conditional allowances will be allocated.	
None	9VAC5-140-6210 I	None.	New subsection added to clarify that implementation of the CCR, ECR and banking adjustment will depend on the extent of the CO_2 trading program.	Needed for clarity.
None	9VAC5-140-6211	None.	Section added for DMME provisions moved from 9VAC5-140-6040 A 2.	Needed for clarity.
None	Article 6	CO_2 Allowance Tracking System	--	--
None	9VAC5-140-6230	Establishment of accounts.	The term "alternate CO_2 authorized account representative" is amended to "CO_2 authorized alternate account representative."	Needed in order to be consistent with new RGGI terminology.
None	9VAC5-140-6260 A 3	*Compliance.	Amended in order for Virginia to recognize offsets generated by other RGGI states.	Needed in order to participate in the RGGI program.
None	Article 8	Monitoring, Reporting and Recordkeeping	--	--
None	9VAC5-140-6330 A	General requirements.	Minor correction.	Needed for clarity.
None	Article 9	Auction of CO_2 CCR and ECR allowances	--	--
None	9VAC5-140-6430	Consignment auction.	Amended to indicate that one quarter of the annual conditional allowance allocation will be consigned by the CO_2 budget source or the holder of a public contract with DMME to each auction. At the completion of the consignment auction, a conditional allowance sold at auction becomes a CO_2 allowance.	Needed for clarity and in order for the program to operate properly.

None	9VAC5-140-6435	None.	New section added to enable the use of a direct auction without consignment in accordance with requirements established by the Virginia General Assembly.	Needed in order for the program to operate properly in the event of a legislative requirement.
None	Article 10	Program Monitoring and Review	--	--
None	9VAC5-140-6440	None.	Article added.	Specifies that in conjunction with program monitoring and review, impacts specific to Virginia will be evaluated, including economic, energy and environmental impacts, and impacts on vulnerable and environmental justice communities. Needed in order to clarify that these specific impacts will be monitored and evaluated.

Changes made after the re-proposal:

Current chapter-section number	**New chapter-section number, if applicable**	**New requirement from previous stage**	**Updated new requirement since previous stage**	**Change, intent, rationale, and likely impact of updated requirements**
None	Article 1	CO_2 Budget Trading Program General Provisions	--	--
None.	9VAC5-140-6020 C	Definition of "adjustment for banked allowances"	Initial control period specified and control period date corrected.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "allocate"	Use consistent and accurate terminology to refer to conditional allowances. Revise to avoid using the word "allocate" within the definition.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definitions of "allocation year"; "allowance auction"	Use consistent and accurate terminology to refer to conditional allowances.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.

None.	9VAC5-140-6020 C	Definition of "CO_2 allowance deduction"; "CO_2 allowance transfer deadline"; "CO_2 budget emissions limitation"	Include "initial control period" when referencing requirements for a control period.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "CO_2 CCR allowance"	Revise to reflect the fact that conditional CCR allowances become CO_2 cost containment reserve allowances after being sold at auction.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "CO_2 ECR allowance"; "CO_2 ECR trigger price"	Use consistent and accurate terminology to refer to conditional allowances; correct minor typos.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "compliance account"	Include "initial control period" when referencing requirements for a control period.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "conditional allowance"	Correct "sources" to "source," and strike the last sentence which is redundant (there is already a separate definition for "conditional CCR allowance").	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "conditional allowance account"	Add definition. §§ 6230 A and 6250 A 1 refer to a "conditional allowance account," but there is no corresponding definition	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "conditional CCR allowance"	Remove reference to a "CCR account" and revise to indicate that an allowance that may be offered for sale when the CCR is triggered	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.

None.	9VAC5-140-6020 C	Definition of "control period"	Refer to the control period from 2021-2023 as the "fifth control period" in order to align with the term used in the existing program. The interim control period start date should be 2021.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "excess emissions"	Include "initial control period" when referencing requirements for a control period.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "reserve price"	Use consistent and accurate terminology to refer to conditional allowances.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definition of "ton" or "tonnage"	Include "initial" and "interim" control periods when referencing requirements for a control period.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6020 C	Definitions of "undistributed CO_2 allowances"; "unsold CO_2 allowances"; "Virginia CO_2 Budget Trading Program adjusted budget"; "Virginia CO_2 Budget Trading Program base budget"	Use consistent and accurate terminology to refer to conditional allowances.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6040 B	*Applicability, exemptions	Restore previously removed term "fossil fuel."	Needed in order to clearly delineate applicability of the regulation, i.e., only fossil fuel-fired facilities are subject to the rule and therefore only fossil fuel-fired facilities can be deemed exempt.
None	9VAC5-140-6045	*Add new section CO_2 Budget Trading Program Implementation	--	Enables the program to proceed should a disruption in the allocation schedule occur. Needed in order to provide an orderly implementation process and certainty to affected facilities and the department should such contingency be necessary.

None.	9VAC5-140-6050 C 1	*General CO_2 requirements	(i) Restore previously removed term "that has been generated as a result of combusting fossil fuel;" (ii) add initial and interim control periods.	Needed in order to (i) clearly delineate applicability of the regulation, and (ii) accurately referencing requirements for various control periods. Needed to meet state requirements, and in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6050 C 2; 9VAC5-140-6050 C 3 and D;	*General CO_2 requirements	Restore previously removed term "that has been generated as a result of combusting fossil fuel" (ii) add initial and interim control periods as appropriate.	Needed in order to (i) clearly delineate applicability of the regulation, and (ii) accurately referencing requirements for various control periods. Needed to meet state requirements, and in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None	Article 4	Compliance certification	--	--
None.	9VAC5-140-6170 A	General CO_2 requirements	Include "initial control period" when referencing requirements for a control period.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None	Article 5	CO_2 Allowance Allocations	--	--
None.	9VAC5-140-6190 B	Base budgets	Amend in order to match the definition of a conditional allowance.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6190 C	*Base budgets	Remove reference to post-2030 requirements and add the updated base budget of 19.60 million tons based on the new 28 million ton cap; specify that the post-2031 base budget may be modified as a result of program review and regulatory action	Needed in order to assure a consistent budget trajectory to the other RGGI participating states and therefore ensure Virginia's ability to participate in the RGGI Program; needed in order to clarify that the post-2031 base budget may be modified as a result of certain actions.

None.	9VAC5-140-6200 A and B	Undistributed and unsold allowances	Include "initial control period" when referencing requirements for a control period.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6210 A through K	CO_2 allowance allocations	Use consistent and accurate terminology to refer to conditional allowances.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6210 C, D, D 1, D 4, D 5, K	CO_2 allowance allocations	Added or modified to describe how allowances flow through the consignment auction account, and to ensure consistent use of the term "Virginia Consignment Auction Account."	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6210 F	CO_2 allowance allocations	Banked allowance adjustment date corrected.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6210 I 1-3	CO_2 allowance allocations	Specific dates replaced with a date within 60 days after the effective date of the rule.	Needed in order for realistic and certain dates to be met.
None.	9VAC5-140-6211; 9VAC5-140-6215 and 6215 A and B 1-3	CO_2 allowance allocations, DMME allowances; CO_2 allocation methodology	Use consistent and accurate terminology to refer to conditional allowances.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6215 C 1 and 2	CO_2 allocation methodology	Specific dates replaced with a date within 60 days after the effective date of the rule.	Needed in order for realistic and certain dates to be met.
None	Article 6	CO_2 Allowance Tracking System	--	--
None.	9VAC5-140-6220 A	CO_2 Allowance Tracking System accounts	Use consistent and accurate terminology to refer to conditional allowances.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6230 A	Establishment of accounts	Because DMME would not need a compliance account, revise to refer to a "conditional allowance account."	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.

None.	9VAC5-140-6250 (entire section)	Recordation of CO_2 allowance allocations	Use consistent and accurate terminology to refer to conditional allowances.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	9VAC5-140-6260 (entire section)	Compliance	Include "initial control period" as appropriate when referencing requirements for a control period.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.
None.	Article 9	Auction of CO_2 CCR and ECR allowances	--	--
None.	9VAC5-140-6420	General requirements	(i) Use consistent and accurate terminology to refer to conditional allowances.; (ii) correct subdivision reference in A 2; (iii) correct term "Virginia Consignment Auction Account" in B 2 and 3; (iv) correct typos in B 4 and 5.	Needed in order for the Virginia consignment auction to operate correctly with the RGGI Program.

REG\DEV\C17-10TF

Attachment 12

VIRGINIA:

IN THE CIRCUIT COURT OF THE CITY OF RICHMOND

RECEIVED
MAR 22 2021
BY:

Virginia Manufacturers Association,

Appellant,

v. Case No.: CL20004918-00

Virginia Department of Environmental Quality, et al.

Appellees.

CERTIFICATION AND NOTICE OF FILING AGENCY RECORD

PLEASE TAKE NOTICE that the Department of Environmental Quality, in accordance with Rule 2A:3 of the Rules of the Virginia Supreme Court, certifies the attached documents are the agency record and files the same as the agency record for this matter.

RESPECTFULLY SUBMITTED,

DAVID K. PAYLOR, DIRECTOR
DEPARTMENT OF ENVIRONMENTAL QUALITY

STATE OF VIRGINIA
~~COUNTY~~ City OF Richmond

The foregoing instrument was acknowledged before me this 18th of March, 2021, by David K. Paylor.

Notary Public Elsie Marie Walker

Printed Name: Elsie Marie Walker My Commission Expires: 1/31/2024

ELSIE MARIE WALKER
NOTARY PUBLIC
Commonwealth of Virginia
Reg. #341333
My Commission Expires 1/31/24

RECEIVED AND FILED
CIRCUIT COURT
MAR 18 2021
EDWARD F. JEWETT, CLERK
BY_____D.C.

Commonwealth of Virginia

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

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Matthew J. Strickler
Secretary of Natural Resources

David K. Paylor
Director
(804) 698-4000

Memorandum

To: David K. Paylor

From: Michael G. Dowd, Director, Air and Renewable Energy Division

Date: June 16, 2020

Subject: Clean Energy and Community Flood Preparedness Act, § 10.1-1329 et seq., RGGI Program Regulation (Part VII of 9VAC5-140)

Introduction

Chapter 1219 of the 2020 Acts of Assembly amends the Air Pollution Control Law to add a new Article 4, the Clean Energy and Community Flood Preparedness Act. Under § 10.1-1330 A, Clean Energy and Community Flood Preparedness, "[T]he provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et seq.)."

Accordingly, we have drafted revisions to Part VII of 9VAC5-140, Regulation for Emissions Trading such that it comports with the full Regional Greenhouse Gas Initiative (RGGI) CO_2 emissions trading program and associated auction as mandated by Chapter 1219 (see Attachment 1). To this end, the draft (i) removes references to a "consignment" auction and its associated mechanisms, such as conditional allowances; (ii) removes DMME allowances; (iii) removes program backstops and other transitional provisions that have been resolved, such as "initial control periods"; and (iv) removes the concept of "linking" to RGGI instead of being a "participating state." (See Attachment 2.)

Additionally, Chapter 1219 adds a new § 10.1-1331, which requires that (i) the definition a "life-of-the-unit contractual arrangement" include any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO_2 budget source or unit and is entitled to receive all of the nameplate

capacity and associated energy generated by such source or unit for the entire contractual period and (ii) any purchaser under an energy conversion or energy tolling agreement is responsible for acquiring any CO_2 allowances required in relation to a CO_2 budget source or unit that is subject to such agreement. The regulation has been amended accordingly (see Attachment 2).

The regulation has been reviewed by the Assistant Attorney General, who concurs that the revisions comport with the RGGI program and thus Chapter 1219 (see Attachment 3). Additionally, the participating RGGI states have reviewed these revisions and agree that they are consistent with the requirements of the RGGI program for full participation.

The final regulation will submitted to the Registrar of Regulations for publication in the Virginia Register at the earliest possible filing date, to become effective upon such filing date.

Recommendation

I recommend that the Director adopt the attached amendments to Part VII of 9VAC5-140 in accordance with Chapter 1219 of the 2020 Acts of Assembly, to be effective upon filing of the amendments with the Virginia Register of Regulations.

Recommendation approved by: David K Paylor

David K. Paylor

Date: 6/25/2020

MGD\kgs
Attachments

REG\DEV\A20-DIR-MEM

CHAPTER 140. REGULATION FOR EMISSIONS TRADING

Part VII. CO_2 Budget Trading Program

Article 1. CO_2 Budget Trading Program General Provisions

9VAC5-140-6010. Purpose.

This part establishes the Virginia component of the CO_2 Budget Trading Program, which is designed to reduce anthropogenic emissions of CO_2, a greenhouse gas, from CO_2 budget sources in a manner that is protective of human health and the environment and is economically efficient.

9VAC5-140-6020. Definitions.

A. As used in this part, all words or terms not defined here shall have the meanings given them in 9VAC5-10 (General Definitions), unless otherwise required by the context.

B. For the purpose of this part and any related use, the words or terms shall have the meanings given them in this section.

C. Terms defined.

"Account number" means the identification number given by the department or its agent to each COATS account.

"Acid ~~rain~~ Rain emission limitation" means, as defined in 40 CFR 72.2, a limitation on emissions of sulfur dioxide (SO_2) or nitrogen oxides (NO_x) under the Acid Rain Program under Title IV of the CAA.

"Acid Rain Program" means a multistate SO_2 and NO_x air pollution control and emission reduction program established by the administrator under Title IV of the CAA and 40 CFR Parts 72 through 78.

"Adjustment for banked allowances" means an adjustment applied to the Virginia CO_2 Budget Trading Program base budget for allocation years 2021 through 2025 to address allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states~~, that are in addition to the aggregate quantity of emissions from all CO_2 budget sources in all of the participating states at the end of the initial control period in 2020 and as reflected in the CO_2 Allowance Tracking System on March 15, 2021~~.

"Administrator" means the administrator of the U.S. Environmental Protection Agency or the administrator's authorized representative.

"Allocate" or "allocation" means the determination by the department of the number of ~~conditional~~ CO_2 allowances recorded in the ~~conditional~~ allowance account of a CO_2 budget unit ~~or to the Department of Mines, Minerals and Energy (DMME) pursuant to 9VAC5-140-6211~~.

"Allocation year" means a calendar year for which the department allocates ~~conditional~~ CO_2 allowances pursuant to Article 5 (9VAC5-140-6190 et seq.) of this part. The allocation year of each ~~conditional~~ CO_2 allowance is reflected in the unique identification number given to the allowance pursuant to 9VAC5-140-6250 C.

"Allowance auction" or "auction" means an auction in which the department or its agent offers ~~conditional~~ CO_2 allowances for sale.

"Attribute" means a characteristic associated with electricity generated using a particular renewable fuel, such as its generation date, facility geographic location, unit vintage, emissions output, fuel, state program eligibility, or other characteristic that can be identified, accounted for, and tracked.

"Attribute credit" means a credit that represents the attributes related to one ~~megawatthour~~ megawatt hour of electricity generation.

"Automated Data Acquisition and Handling System" or "DAHS" means that component of the Continuous Emissions Monitoring System (CEMS), or other emissions monitoring system approved for use under Article 8 (9VAC5-140-6330 et seq.) of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by Article 8 (9VAC5-140-6330 et seq.) of this part.

"Billing meter" means a measurement device used to measure electric or thermal output for commercial billing under a contract. The facility selling the electric or thermal output shall have different owners from the owners of the party purchasing the electric or thermal output.

"Boiler" means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

"CO_2 allowance" means a limited authorization by the department or ~~another~~ participating state under the CO_2 Budget Trading Program to emit up to one ton

of CO_2, subject to all applicable limitations contained in this part. ~~CO_2 offset allowances generated by other participating states will be recognized by the department.~~

"CO_2 allowance deduction" or "deduct CO_2 allowances" means the permanent withdrawal of CO_2 allowances by the department or its agent from a COATS compliance account to account for the number of tons of CO_2 emitted from a CO_2 budget source for ~~the initial control period,~~ a control period ~~,~~ or an interim control period determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, or for the forfeit or retirement of CO_2 allowances as provided by this part.

"CO_2 Allowance Tracking System" or "COATS" means the system by which the department or its agent records allocations, deductions, and transfers of CO_2 allowances under the CO_2 Budget Trading Program. The tracking system may also be used to track CO_2 allowance prices and emissions from affected sources.

"CO_2 Allowance Tracking System account" means an account in COATS established by the department or its agent for purposes of recording the allocation, holding, transferring, or deducting of CO_2 allowances.

"CO_2 allowance transfer deadline" means midnight of March 1 occurring after the end of the ~~initial~~ relevant control period~~, the control period,~~ and each relevant interim control period, or if that March 1 is not a business day, midnight of the first business day thereafter and is the deadline by which CO_2 allowances shall be submitted for recordation in a CO_2 budget source's compliance account for the source to meet the CO_2 requirements of 9VAC5-140-6050 C for ~~the initial control period,~~ a control period ~~,~~ and each interim control period immediately preceding such deadline.

"CO_2 allowances held" or "hold CO_2 allowances" means the CO_2 allowances recorded by the department or its agent, or submitted to the department or its agent for recordation, in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 7 (9VAC5-140-6300 et seq.) of this part, in a COATS account.

"CO_2 authorized account representative" means, for a CO_2 budget source and each CO_2 budget unit at the source, the natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Article 2 (9VAC5-140-6080 et seq.) of this part, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the natural person who is authorized, under Article 6 (9VAC5-140-6220 et seq.) of this part, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then for a CO_2 Budget Trading Program compliance account, this natural person shall be the same person as the designated representative as defined in the respective program.

"CO_2 authorized alternate account representative" means, for a CO_2 budget source and each CO_2 budget unit at the source, the alternate natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Article 2 (9VAC5-140-6080 et seq.) of this part, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the alternate natural person who is authorized, under Article 6 (9VAC5-140-6220 et seq.) of this part, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program then, for a CO_2 Budget Trading Program compliance account, this alternate natural person shall be the same person as the alternate designated representative as defined in the respective program.

"CO_2 budget emissions limitation" means, for a CO_2 budget source, the tonnage equivalent, in CO_2 emissions in ~~the initial control period,~~ a control period ~~,~~ or an interim control period of the CO_2 allowances available for compliance deduction for the source for a control period or an interim control period.

"CO_2 budget permit" means the portion of the legally binding permit issued by the department pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) to a CO_2 budget source or CO_2 budget unit that specifies the CO_2 Budget Trading Program requirements applicable to the CO_2 budget source, to each CO_2 budget unit at the CO_2 budget source, and to the owners and operators and the CO_2 authorized account representative of the CO_2 budget source and each CO_2 budget unit.

"CO_2 budget source" means a source that includes one or more CO_2 budget units.

"CO_2 Budget Trading Program" means a multistate CO_2 air pollution control and emissions reduction program established according to this part and corresponding regulations in other states as a means of reducing emissions of CO_2 from CO_2 budget sources.

"CO_2 budget unit" means a unit that is subject to the CO_2 Budget Trading Program requirements under 9VAC5-140-6040.

"CO_2 cost containment reserve allowance" or "CO_2 CCR allowance" means an allowance that has been sold at an auction for the purpose of containing the cost of CO_2 allowances. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program base and adjusted budgets. CO_2 CCR allowances are subject to all applicable limitations contained in this part.

"CO_2 cost containment reserve trigger price" or "CCR trigger price" means the minimum price at which CO_2 CCR allowances are offered for sale by the department or its agent at an auction. The CCR trigger price in calendar year ~~2020~~ 2021 shall be ~~$10.77~~ $13.00. The CCR trigger price in calendar year ~~2021~~ 2022 shall be ~~$13~~ $13.91. Each calendar year thereafter, the CCR trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1A.

Table 140-1A
CO_2 CCR Trigger Price

~~2020~~	~~$10.77~~
2021	$13.00
2022	$13.91
2023	$14.88
2024	$15.92
2025	$17.03
2026	$18.22
2027	$19.50
2028	$20.87
2029	$22.33
2030	$23.89

"CO_2 emissions containment reserve allowance" or "CO_2 ECR allowance" means a ~~conditional~~ CO_2 allowance that is withheld from sale at an auction by the department for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.

"CO_2 emissions containment reserve trigger price" or "ECR trigger price" means the price below which ~~conditional~~ CO_2 allowances will be withheld from sale by the department or its agent at an auction. The ECR trigger price in calendar year 2021 shall be $6.00. Each calendar year thereafter, the ECR trigger price shall be 1.07 multiplied by the ECR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1B.

Table 140-1B
CO_2 ECR Trigger Price

2021	$ 6.00
2022	$ 6.42
2023	$ 6.87
2024	$ 7.35
2025	$ 7.86
2026	$8.41
2027	$ 9.00

2028	$ 9.63
2029	$10.30
2030	$11.02

"CO_2 offset allowance" means a CO_2 allowance that is awarded to the sponsor of a CO_2 emissions offset project by a participating state and is subject to the relevant compliance deduction limitations of the participating state's corresponding offset regulations as a means of reducing CO_2 from CO_2 budget sources.

"Combined cycle system" means a system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

"Combustion turbine" means an enclosed fossil or other fuel-fired device that is comprised of a compressor (if applicable), a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

"Commence commercial operation" means, with regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. For a unit that is a CO_2 budget unit under 9VAC5-140-6040 on the date the unit commences commercial operation, such date shall remain the unit's date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under 9VAC5-140-6040 on the date the unit commences commercial operation, the date the unit becomes a CO_2 budget unit under 9VAC5-140-6040 shall be the unit's date of commencement of commercial operation.

"Commence operation" means to begin any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber. For a unit that is a CO_2 budget unit under 9VAC5-140-6040 on the date of commencement of operation, such date shall remain the unit's date of commencement of operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under 9VAC5-140-6040 on the date of commencement of operation, the date the unit becomes a CO_2 budget unit under 9VAC5-140-6040 shall be the unit's date of commencement of operation.

"Compliance account" means a COATS account, established by the department or its agent for a CO_2 budget source under Article 6 (9VAC5-140-6220 et seq.) of this part, in which CO_2 allowances available for use by the source for ~~the initial control period,~~ a control period ~~,~~ and each interim control period are held for the purpose of meeting the CO_2 requirements of 9VAC5-140-6050 C.

~~"Conditional allowance" means an allowance allocated by the department to a CO_2 budget source or to DMME. Such conditional allowance shall be consigned by~~

~~the entity to whom it is allocated to the consignment auction as specified under Article 9 (9VAC5-140-6410 et seq.) of this part, after which the conditional allowance becomes a CO_2 allowance once it is sold to an auction participant.~~

~~"Conditional allowance account" means a general COATS account established by the department for CO_2 budget sources and DMME or its contractor where conditional allowances allocated to CO_2 budget sources and DMME are held until auction.~~

~~"Conditional cost containment reserve allowance" or "conditional CCR allowance" means an allowance that may be offered for sale when the CCR is triggered. If any conditional CCR allowances are unsold, they may be offered for sale in future auctions during the same year. Conditional CCR allowances offered for sale at an auction are separate from and additional to conditional allowances allocated from the Virginia CO_2 Budget Trading Program base and adjusted budgets. Conditional CCR allowances are subject to all applicable limitations contained in this part.~~

~~"Consignment auction" or "auction" means the CO_2 auction conducted on a quarterly basis by the CO_2 Budget Trading Program, in which CO_2 budget sources and DMME are allocated a share of allowances by the department that CO_2 budget sources and the holder of a public contract with DMME consign into the auction, and auction revenue is returned to CO_2 budget sources and the holder of a public contract with DMME in accordance with procedures established by the department.~~

"Continuous Emissions Monitoring System" or "CEMS" means the equipment required under Article 8 (9VAC5-140-6330 et seq.) of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated DAHS), a permanent record of stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with 40 CFR Part 75 and Article 8 (9VAC5-140-6330 et seq.) of this part. The following systems are types of CEMS required under Article 8 (9VAC5-140-6330 et seq.) of this part:

a. A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour;

b. A NO_X emissions rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated DAHS and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emissions rate, in pounds per million British thermal units (lb/MMBtu);

c. A moisture monitoring system, as defined in 40 CFR 75.11(b)(2) and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

d. A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated DAHS and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

e. An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated DAHS and providing a permanent, continuous record of O_2, in percent O_2.

"Control period" means a three-calendar-year time period. The fifth control period is from January 1, 2021, to December 31, 2023, inclusive, which is the first control period of Virginia's participation in the CO_2 Budget Trading Program. The first two calendar years of each control period are each defined as an interim control period, beginning on January 1, 2021.

"Cross State Air Pollution Rule (CSAPR) NO_X Annual Trading Program" means a multistate NO_X air pollution control and emission reduction program established in accordance with Subpart AAAAA of 40 CFR Part 97 and 40 CFR 52.38(a), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.38(a)(3) or (4) or that is established in a SIP revision approved by the administrator under 40 CFR 52.38(a)(5), as a means of mitigating interstate transport of fine particulates and NO_X.

"Cross State Air Pollution Rule (CSAPR) NO_X Ozone Season Trading Program" means a multistate NO_X air pollution control and emission reduction program established in accordance with Subpart BBBBB of 40 CFR Part 97 and 40 CFR 52.38(b), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.38(b)(3) or (4) or that is established in a SIP revision approved by the administrator under 40 CFR 52.38(b)(5), as a means of mitigating interstate transport of ozone and NO_X.

"Cross State Air Pollution Rule (CSAPR) SO_2 Group 1 Trading Program" means a multistate SO_2 air pollution control and emission reduction program established in accordance with Subpart CCCCC of 40 CFR Part 97 and 40 CFR 52.39(a), (b), (d) through (f), (j), and (k), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.39(d) or (e) or that is established in a SIP revision approved by the administrator under 40 CFR 52.39(f), as a means of mitigating interstate transport of fine particulates and SO_2.

"Cross State Air Pollution Rule (CSAPR) SO_2 Group 2 Trading Program" means a multistate SO_2 air pollution control and emission reduction program

established in accordance with Subpart DDDDD of 40 CFR Part 97 and 40 CFR 52.39(a), (c), and (g) through (k), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.39(g) or (h) or that is established in a SIP revision approved by the administrator under 40 CFR 52.39(i), as a means of mitigating interstate transport of fine particulates and SO_2.

"Department" means the Virginia Department of Environmental Quality.

~~"DMME" means the Virginia Department of Mines, Minerals and Energy.~~

"Excess emissions" means any tonnage of CO_2 emitted by a CO_2 budget source during ~~the initial~~ an interim control period or a control period that exceeds the CO_2 budget emissions limitation for the source.

"Excess interim emissions" means any tonnage of CO_2 emitted by a CO_2 budget source during an interim control period multiplied by 0.50 that exceeds the CO_2 budget emissions limitation for the source.

"Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

"Fossil fuel-fired" means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 5.0% of the annual heat input on a Btu basis during any year.

"General account" means a COATS account established under Article 6 (9VAC5-140-6220 et seq.) of this part that is not a compliance account.

"Gross generation" means the electrical output in MWe at the terminals of the generator.

~~"Initial control period" means the period beginning January 1, 2020, and ending December 31, 2020.~~

"Interim control period" means a one-calendar-year time period during each of the first and second calendar years of each three-year control period. The first interim control period starts January 1, 2021, and ends December 31, 2021, inclusive. The second interim control period starts January 1, 2022, and ends December 31, 2022, inclusive. Each successive three-year control period will have two interim control periods, comprised of each of the first two calendar years of that control period.

"Life-of-the-unit contractual arrangement" means either:

~~a~~ a. A unit participation power sales agreement under which a customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity or associated energy from any specified unit pursuant to a contract:

~~a.~~ 1. For the life of the unit;

~~b.~~ 2. For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

~~c.~~ 3. For a period equal to or greater than 25 years or 70% of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period~~.~~ ; or

b. For any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO_2 budget source or CO_2 budget unit and is entitled to receive all of the nameplate capacity and associated energy generated by such source or unit for the entire contractual period. Such agreements shall be subject to 9VAC5-140-6325. Such purchaser shall not be considered an "owner" as defined under this subsection.

"Maximum potential hourly heat input" means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use Appendix D of 40 CFR Part 75 to report heat input, this value shall be calculated, in accordance with 40 CFR Part 75, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value shall be reported, in accordance with 40 CFR Part 75, using the maximum potential flow rate and either the maximum CO_2 concentration in percent CO_2 or the minimum O_2 concentration in percent O_2.

"Minimum reserve price" means, in calendar year ~~2020, $2.32~~ 2021, $2.38. Each calendar year thereafter, the minimum reserve price shall be 1.025 multiplied by the minimum reserve price from the previous calendar year, rounded to the nearest whole cent.

"Monitoring system" means any monitoring system that meets the requirements of Article 8 (9VAC5-140-6330 et seq.) of this part, including a CEMS, an excepted monitoring system, or an alternative monitoring system.

"Nameplate capacity" means the maximum electrical output in MWe that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the U.S. Department of Energy standards.

"Net-electric output" means the amount of gross generation in MWh the generators produce, including output from steam turbines, combustion turbines, and gas expanders, as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

"Non-CO_2 budget unit" means a unit that does not meet the applicability criteria of 9VAC5-140-6040.

"Operator" means any person who operates, controls, or supervises a CO_2 budget unit or a CO_2 budget source and shall include any holding company, utility system, or plant manager of such a unit or source.

"Owner" means any of the following persons:

a. Any holder of any portion of the legal or equitable title in a CO_2 budget unit;

b. Any holder of a leasehold interest in a CO_2 budget unit, other than a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the CO_2 budget unit;

c. Any purchaser of power from a CO_2 budget unit under a life-of-the-unit contractual arrangement in which the purchaser controls the dispatch of the unit; or

d. With respect to any general account, any person who has an ownership interest with respect to the CO_2 allowances held in the general account and who is subject to the binding agreement for the CO_2 authorized account representative to represent that person's ownership interest with respect to the CO_2 allowances.

"Participating state" means a state that ~~participates in~~ has established a corresponding regulation as part of the CO_2 Budget Trading Program.

"Receive" or "receipt of" means, when referring to the department or its agent, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission) as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence by the department or its agent in the regular course of business.

"Recordation," "record," or "recorded" means, with regard to CO_2 allowances, the movement of CO_2 allowances by the department or its agent from one COATS account to another, for purposes of allocation, transfer, or deduction.

"Reserve price" means the minimum acceptable price for each ~~conditional~~ CO_2 allowance in a specific auction. The reserve price at an auction is either the minimum reserve price or the CCR trigger price, as specified in Article 9 (9VAC5-140-6410 et seq.) of this part.

"Serial number" means, when referring to CO_2 allowances, the unique identification number assigned to each CO_2 allowance by the department or its agent under 9VAC5-140-6250 C.

"Source" means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any air pollutant. A source, including a source with multiple units, shall be considered a single facility.

"Submit" or "serve" means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

a. In person;

b. By United States Postal Service; or

c. By other means of dispatch or transmission and delivery.

Compliance with any "submission," "service," or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

"Ton" or "tonnage" means any short ton, or 2,000 pounds. For the purpose of determining compliance with the CO_2 requirements of 9VAC5-140-6050 C, total tons for ~~the initial control period,~~ an interim control period , or a control period shall be calculated as the sum of all recorded hourly emissions, or the tonnage equivalent of the recorded hourly emissions rates, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons. A short ton is equal to 0.9072 metric tons.

"Total useful energy" means the sum of gross electrical generation and useful net thermal energy.

"Undistributed ~~conditional~~ CO_2 allowances" means ~~conditional~~ CO_2 allowances originally allocated to a set aside account as pursuant to 9VAC5-140-6210 that were not distributed.

"Unit" means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

"Unit operating day" means a calendar day in which a unit combusts any fuel.

"Unsold ~~conditional~~ CO_2 allowances" means ~~conditional~~ CO_2 allowances that have been made available for sale in an auction conducted by the department or its agent, but not sold.

"Useful net thermal energy" means energy:

~~1.~~ a. In the form of direct heat, steam, hot water, or other thermal form that is used in the production and beneficial measures for heating, cooling, humidity control, process use, or other thermal end use energy requirements, excluding thermal energy used in the power production process (e.g., house loads and parasitic loads); and

~~2.~~ b. For which fuel or electricity would otherwise be consumed.

"Virginia CO_2 Budget Trading Program adjusted budget" means an adjusted budget determined in accordance with 9VAC5-140-6210 and is the annual amount of CO_2 tons available in Virginia for allocation in a given allocation year, in accordance with the CO_2 Budget Trading Program. ~~Conditional~~ CO_2 CCR allowances offered for sale at an auction are separate from and additional to ~~conditional~~ CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program adjusted budget.

"Virginia CO_2 Budget Trading Program base budget" means the budget specified in 9VAC5-140-6190. ~~Conditional~~ CO_2 CCR allowances offered for sale at an auction are separate from and additional to ~~conditional~~ CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program base budget.

9VAC5-140-6030. Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu - British thermal unit.
CAA - federal Clean Air Act.
CCR - cost containment reserve.
CEMS - Continuous Emissions Monitoring System.
COATS - CO_2 Allowance Tracking System.
CO_2 - carbon dioxide.
DAHS - Data Acquisition and Handling System.
H2O - water.
lb - pound.
LME - low mass emissions.

MMBtu - million British thermal units.
MW - megawatt.
MWe - megawatt electrical.
MWh - megawatt hour.
NO_X - nitrogen oxides.
O2 - oxygen.
ORIS - Office of Regulatory Information Systems.
QA/QC - quality assurance/quality control.
ppm - parts per million.
SO_2 - sulfur dioxide.

9VAC5-140-6040. Applicability.

A. Any fossil fuel-fired unit that serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe shall be a CO_2 budget unit, and any source that includes one or more such units shall be a CO_2 budget source, subject to the requirements of this part.

B. Exempt from the requirements of this part is any fossil fuel CO_2 budget source located at or adjacent to and physically interconnected with a manufacturing facility that, prior to January 1, ~~2019~~ 2020, and in every subsequent calendar year, met either of the following requirements:

1. Supplies less than or equal to 10% of its annual net electrical generation to the electric grid; or

2. Supplies less than or equal to 15% of its annual total useful energy to any entity other than the manufacturing facility to which the CO_2 budget source is interconnected.

For the purpose of subdivision 1 of this subsection, annual net electrical generation shall be determined as follows:

$$(ES - EP) / EG \times 100$$

Where:

ES = electricity sales to the grid from the CO_2 budget source
EP = electricity purchases from the grid by the CO_2 budget source and the manufacturing facility to which the CO_2 budget source is interconnected
EG = electricity generation

Such exempt CO_2 budget source shall have an operating permit containing the applicable restrictions under this subsection. An application for such operating permit shall be submitted to the department no later than January 1, 2022.

9VAC5-140-6045. ~~CO_2 Budget Trading Program implementation.~~ (Repealed.)

~~In the event the allocation of conditional allowances by the department as required by 9VAC5-140-6190 B has not occurred by January 1, 2020, the program will be considered to be operating and effective as of the calendar year following the date on which the department allocates the conditional allowances as it corresponds to the schedule of 9VAC5-140-6190 A. Permitting and compliance dates, including the due date for a permit as required by 9VAC5-140-6150 , shall be adjusted to be in force six months after the date the department allocates the conditional allowances. Any excess emissions tonnage identified by the new program implementation date may be addressed through program review and regulatory action as necessary to ensure compliance with the final compliance date. The department will notify the board and each affected CO_2 budget source accordingly.~~

9VAC5-140-6050. Standard requirements.

A. Permit requirements shall be as follows.

1. The CO_2 authorized account representative of each CO_2 budget source required to have an operating permit pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) and each CO_2 budget unit required to have an operating permit pursuant to 9VAC5-85 shall:

a. Submit to the department a complete CO_2 budget permit application under 9VAC5-140-6160 in accordance with the deadlines specified in 9VAC5-140-6150; and

b. Submit in a timely manner any supplemental information that the department determines is necessary in order to review the CO_2 budget permit application and issue or deny a CO_2 budget permit.

2. The owners and operators of each CO_2 budget source required to have an operating permit pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) and each CO_2 budget unit required to have an operating permit pursuant to 9VAC5-85 for the source shall have a CO_2 budget permit and operate the CO_2 budget source and the CO_2 budget unit at the source in compliance with such CO_2 budget permit.

B. Monitoring requirements shall be as follows.

1. The owners and operators and, to the extent applicable, the CO_2 authorized account representative of each CO_2 budget source and each CO_2 budget unit at the source shall comply with the monitoring requirements of Article 8 (9VAC5-140-6330 et seq.) of this part.

2. The emissions measurements recorded and reported in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part shall be used to determine compliance by the unit with the CO_2 requirements under subsection C of this section.

C. CO_2 requirements shall be as follows.

1. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions that have been generated as a result of combusting fossil fuel for ~~the initial control period,~~ an interim control period ~~,~~ or control period from all CO_2 budget units at the source, less the CO_2 allowances deducted to meet the requirements of subdivision 2 of this subsection, with respect to the previous two interim control periods as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part.

2. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions that have been generated as a result of combusting fossil fuel for ~~the initial control period, an interim control period, or for~~ the interim control period from all CO_2 budget units at the source multiplied by 0.50, as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part.

3. Each ton of CO_2 emitted in excess of the CO_2 budget emissions limitation for ~~the initial control period or~~ a control period shall constitute a separate violation of this part and applicable state law.

4. Each ton of excess interim emissions shall constitute a separate violation of this part and applicable state law.

5. A CO_2 budget unit shall be subject to the requirements under subdivision 1 of this subsection starting on the later of January 1, ~~2020~~ 2021, or the date on which the unit commences operation.

6. CO_2 allowances shall be held in, deducted from, or transferred among COATS accounts in accordance with Article 5 (9VAC5-140-6190 et seq.), Article 6 (9VAC5-140-6220 et seq.), and Article 7 (9VAC5-140-6300 et seq.) of this part.

7. A CO_2 allowance shall not be deducted, to comply with the requirements under subdivision 1 or 2 of this subsection, for a control period that ends prior to the year for which the CO_2 allowance was allocated.

8. A CO_2 allowance under the CO_2 Budget Trading Program is a limited authorization by the department to emit one ton of CO_2 in accordance with the CO_2 Budget Trading Program. No provision of the CO_2 Budget Trading Program, the CO_2 budget permit application, or the CO_2 budget permit or any provision of law shall be construed to limit the authority of the department or a participating state to terminate or limit such authorization.

9. A CO_2 allowance under the CO_2 Budget Trading Program does not constitute a property right.

D. The owners and operators of a CO_2 budget source that has excess emissions in ~~an initial control period or~~ a control period shall:

1. Forfeit the CO_2 allowances required for deduction under 9VAC5-140-6260 D 1; and

2. Pay any fine, penalty, or assessment or comply with any other remedy imposed under 9VAC5-140-6260 D 2.

E. Recordkeeping and reporting requirements shall be as follows:

1. Unless otherwise provided, the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source shall keep on site at the source each of the following documents for a period of 10 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 10 years, in writing by the department.

a. The account certificate of representation for the CO_2 authorized account representative for the source and each CO_2 budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 9VAC5-140-6110, provided that the certificate and documents shall be retained on site at the source beyond such 10-year period until such documents are superseded because of the submission of a new account certificate of representation changing the CO_2 authorized account representative.

b. All emissions monitoring information, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part and 40 CFR 75.57.

c. Copies of all reports, compliance certifications, and other submissions and all records made or required under the CO_2 Budget Trading Program.

d. Copies of all documents used to complete a CO_2 budget permit application and any other submission under the CO_2 Budget Trading Program or to demonstrate compliance with the requirements of the CO_2 Budget Trading Program.

2. The CO_2 authorized account representative of a CO_2 budget source and each CO_2 budget unit at the source shall submit the reports and compliance certifications required under the CO_2 Budget Trading Program, including those under Article 4 (9VAC5-140-6170 et seq.) of this part.

F. Liability requirements shall be as follows.

1. No permit revision shall excuse any violation of the requirements of the CO_2 Budget Trading Program that occurs prior to the date that the revision takes effect.

2. Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget source, including a provision applicable to the CO_2 authorized account representative of a CO_2 budget source, shall also apply to the owners and operators of such source and of the CO_2 budget units at the source.

3. Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget unit, including a provision applicable to the CO_2 authorized account representative of a CO_2 budget unit, shall also apply to the owners and operators of such unit.

G. No provision of the CO_2 Budget Trading Program, a CO_2 budget permit application, or a CO_2 budget permit shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the CO_2 authorized account representative of the CO_2 budget source or CO_2 budget unit from compliance with any other provisions of applicable state and federal law or regulations.

9VAC5-140-6060. Computation of time.

A. Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

B. Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

C. Unless otherwise stated, if the final day of any time period, under the CO_2 Budget Trading Program, falls on a weekend or a state or federal holiday, the time period shall be extended to the next business day.

9VAC5-140-6070. Severability.

If any provision of this part, or its application to any particular person or circumstances, is held invalid, the remainder of this part, and the application thereof to other persons or circumstances, shall not be affected thereby.

Article 2. CO_2 Authorized Account Representative for CO_2 Budget Sources

9VAC5-140-6080. Authorization and responsibilities of the CO_2 authorized account representative.

A. Except as provided under 9VAC5-140-6090, each CO_2 budget source, including all CO_2 budget units at the source, shall have one and only one CO_2 authorized account representative, with regard to all matters under the CO_2 Budget Trading Program concerning the source or any CO_2 budget unit at the source.

B. The CO_2 authorized account representative of the CO_2 budget source shall be selected by an agreement binding on the owners and operators of the source and all CO_2 budget units at the source and must act in accordance with the account certificate of representation under 9VAC5-140-6110.

C. Upon receipt by the department or its agent of a complete account certificate of representation under 9VAC5-140-6110 , the CO_2 authorized account representative of the source shall represent and, by his representations, actions, inactions, or submissions, legally bind each owner and operator of the CO_2 budget source represented and each CO_2 budget unit at the source in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CO_2 authorized account representative by the department or a court regarding the source or unit.

D. No CO_2 budget permit shall be issued, and no COATS account shall be established for a CO_2 budget source, until the department or its agent has received a complete account certificate of representation under 9VAC5-140-6110 for a CO_2 authorized account representative of the source and the CO_2 budget units at the source.

E. Each submission under the CO_2 Budget Trading Program shall be submitted, signed, and certified by the CO_2 authorized account representative for each CO_2 budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CO_2 authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting

false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

F. The department or its agent will accept or act on a submission made on behalf of owners or operators of a CO_2 budget source or a CO_2 budget unit only if the submission has been made, signed, and certified in accordance with subsection E of this section.

9VAC5-140-6090. CO_2 authorized alternate account representative.

A. An account certificate of representation may designate one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative.

B. Upon receipt by the department or its agent of a complete account certificate of representation under 9VAC5-140-6110, any representation, action, inaction, or submission by the CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

C. Except in this section and 9VAC5-140-6080 A, 9VAC5-140-6100, 9VAC5-140-6110, and 9VAC5-140-6230, whenever the term "CO_2 authorized account representative" is used in this part, the term shall be construed to include the CO_2 authorized alternate account representative.

9VAC5-140-6100. Changing the CO_2 authorized account representatives and the CO_2 authorized alternate account representative; changes in the owners and operators.

A. The CO_2 authorized account representative may be changed at any time upon receipt by the department or its agent of a superseding complete account certificate of representation under 9VAC5-140-6110. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative or CO_2 authorized alternate account representative prior to the time and date when the department or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

B. The CO_2 authorized alternate account representative may be changed at any time upon receipt by the department or its agent of a superseding complete account certificate of representation under 9VAC5-140-6110. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized

alternate account representative or CO_2 authorized alternate account representative prior to the time and date when the department or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized alternate account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

C. Changes in the owners and operators shall be addressed as follows.

1. In the event a new owner or operator of a CO_2 budget source or a CO_2 budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative of the source or unit, and the decisions, orders, actions, and inactions of the department, as if the new owner or operator were included in such list.

2. Within 30 days following any change in the owners and operators of a CO_2 budget source or a CO_2 budget unit, including the addition of a new owner or operator, the CO_2 authorized account representative or CO_2 authorized alternate account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.

9VAC5-140-6110. Account certificate of representation.

A. A complete account certificate of representation for a CO_2 authorized account representative or a CO_2 authorized alternate account representative shall include the following elements in a format prescribed by the department or its agent:

1. Identification of the CO_2 budget source and each CO_2 budget unit at the source for which the account certificate of representation is submitted;

2. The name, address, email address, telephone number, and facsimile transmission number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

3. A list of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source;

4. The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: "I certify that I was selected as the CO_2 authorized account representative or CO_2 authorized alternate account representative, as applicable, by an agreement binding on the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under

the CO_2 Budget Trading Program on behalf of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the department or a court regarding the source or unit."; and

5. The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed.

B. Unless otherwise required by the department or its agent, documents of agreement referred to in the account certificate of representation shall not be submitted to the department or its agent. Neither the department nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

9VAC5-140-6120. Objections concerning the CO_2 authorized account representative.

A. Once a complete account certificate of representation under 9VAC5-140-6110 has been submitted and received, the department and its agent will rely on the account certificate of representation unless and until the department or its agent receives a superseding complete account certificate of representation under 9VAC5-140-6110.

B. Except as provided in 9VAC5-140-6100 A or B, no objection or other communication submitted to the department or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or the finality of any decision or order by the department or its agent under the CO_2 Budget Trading Program.

C. Neither the department nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CO_2 authorized account representative, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

9VAC5-140-6130. Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative.

A. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent under this part.

B. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent under this part.

C. To delegate authority to make an electronic submission to the department or its agent in accordance with subsections A and B of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

1. The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

2. The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as the "electronic submission agent";

3. For each such natural person, a list of the type of electronic submissions under subsection A or B of this section for which authority is delegated to him; and

4. The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any electronic submission to the department or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6130 D shall be deemed to be an electronic submission by me. Until this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6130 D, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under 9VAC5-140-6130 is terminated."

D. A notice of delegation submitted under subsection C of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

E. Any electronic submission covered by the certification in subdivision C 4 of this section and made in accordance with a notice of delegation effective under subsection D of this section shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

F. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to review information in the CO_2 allowance tracking system under this part.

G. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to review information in the CO_2 allowance tracking system under this part.

H. To delegate authority to review information in the CO_2 allowance tracking system in accordance with subsections F and G of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

1. The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

2. The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as the "reviewer";

3. For each such natural person, a list of the type of information under subsection F or G of this section for which authority is delegated to him; and

4. The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any information that is reviewed by a natural person identified in this notice of delegation and of a type listed for such information accessible by the reviewer in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subsection I of this section shall be deemed to be a reviewer by me. Until this notice of delegation is superseded by another notice of delegation under subsection I of this section, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under this section is terminated."

I. A notice of delegation submitted under subsection H of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of

delegation may replace any previously identified reviewer, add a new reviewer, or eliminate entirely any delegation of authority.

Article 3. Permits

9VAC5-140-6140. CO_2 budget permit requirements.

A. Each CO_2 budget source shall have a permit issued by the department pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation).

B. Each CO_2 budget permit shall contain all applicable CO_2 Budget Trading Program requirements and shall be a complete and distinguishable portion of the permit under subsection A of this section.

9VAC5-140-6150. Submission of CO_2 budget permit applications.

For any CO_2 budget source, the CO_2 authorized account representative shall submit a complete CO_2 budget permit application under 9VAC5-140-6160 covering such CO_2 budget source to the department by the later of January 1, ~~2020~~ 2021, or 12 months before the date on which the CO_2 budget source, or a new unit at the source, commences operation.

9VAC5-140-6160. Information requirements for CO_2 budget permit applications.

A complete CO_2 budget permit application shall include the following elements concerning the CO_2 budget source for which the application is submitted, in a format prescribed by the department:

1. Identification of the CO_2 budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration of the U.S. Department of Energy if applicable;

2. Identification of each CO_2 budget unit at the CO_2 budget source; and

3. The standard requirements under 9VAC5-140-6050.

Article 4. Compliance Certification

9VAC5-140-6170. Compliance certification report.

A. For ~~the initial control period and~~ each control period in which a CO_2 budget source is subject to the CO_2 requirements of 9VAC5-140-6050 C, the CO_2 authorized account representative of the source shall submit to the department by March 1 following the relevant control period, a compliance certification report. A compliance

certification report is not required as part of the compliance obligation during an interim control period.

B. The CO_2 authorized account representative shall include in the compliance certification report under subsection A of this section the following elements, in a format prescribed by the department:

1. Identification of the source and each CO_2 budget unit at the source;

2. At the CO_2 authorized account representative's option, the serial numbers of the CO_2 allowances that are to be deducted from the source's compliance account under 9VAC5-140-6260 for the control period; and

3. The compliance certification under subsection C of this section.

C. In the compliance certification report under subsection A of this section, the CO_2 authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the CO_2 budget units at the source in compliance with the CO_2 Budget Trading Program, whether the source and each CO_2 budget unit at the source for which the compliance certification is submitted was operated during the calendar years covered by the report in compliance with the requirements of the CO_2 Budget Trading Program, including:

1. Whether the source was operated in compliance with the CO_2 requirements of 9VAC5-140-6050 C;

2. Whether the monitoring plan applicable to each unit at the source has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute CO_2 emissions to the unit, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part;

3. Whether all the CO_2 emissions from the units at the source were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

4. Whether the facts that form the basis for certification under Article 8 (9VAC5-140-6330 et seq.) of this part of each monitor at each unit at the source, or for using an excepted monitoring method or alternative monitoring method approved under Article 8 (9VAC5-140-6330 et seq.) of this part, if any, have changed; and

5. If a change is required to be reported under subdivision 4 of this subsection, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

9VAC5-140-6180. Action on compliance certifications.

A. The department or its agent may review and conduct independent audits concerning any compliance certification or any other submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions.

B. The department or its agent may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on the information in the compliance certifications or other submissions, as adjusted under subsection A of this section.

Article 5. CO_2 Allowance Allocations

9VAC5-140-6190. Base budgets.

A. The Virginia CO_2 Budget Trading Program base budget shall be as follows:

1. ~~For 2020, the Virginia CO_2 Budget Trading Program base budget is 28 million tons.~~

~~2.~~ For 2021, the Virginia CO_2 Budget Trading Program base budget is 27.16 million tons.

~~3.~~ 2. For 2022, the Virginia CO_2 Budget Trading Program base budget is 26.32 million tons.

~~4.~~ 3. For 2023, the Virginia CO_2 Budget Trading Program base budget is 25.48 million tons.

~~5.~~ 4. For 2024, the Virginia CO_2 Budget Trading Program base budget is 24.64 million tons.

~~6.~~ 5. For 2025, the Virginia CO_2 Budget Trading Program base budget is 23.80 million tons.

~~7.~~ 6. For 2026, the Virginia CO_2 Budget Trading Program base budget is 22.96 million tons.

~~8.~~ 7. For 2027, the Virginia CO_2 Budget Trading Program base budget is 22.12 million tons.

~~9.~~ 8. For 2028, the Virginia CO_2 Budget Trading Program base budget is 21.28 million tons.

~~10.~~ 9. For 2029, the Virginia CO_2 Budget Trading Program base budget is 20.44 million tons.

~~11.~~ 10. For 2030, the Virginia CO_2 Budget Trading Program base budget is 19.60 million tons.

B. ~~The department will allocate conditional allowances to CO_2 budget units and to DMME. After a conditional allowance has been consigned in an auction by a CO_2 budget unit or the holder of a public contract with DMME as specified under Article 9 (9VAC5-140-6410 et seq.) of this part, the conditional allowance becomes a CO_2 allowance once it is sold to an auction participant.~~

~~C.~~ For 2031 and each succeeding calendar year, the Virginia CO_2 Budget Trading Program base budget is 19.60 million tons unless modified as a result of a program review and future regulatory action.

9VAC5-140-6200. Undistributed and unsold ~~conditional~~ CO_2 allowances.

A. The department will retire undistributed ~~conditional~~ CO_2 allowances at the end of ~~the initial control period and~~ each ~~subsequent~~ control period.

B. The department will retire unsold ~~conditional~~ CO_2 allowances at the end of ~~the initial control period and~~ each ~~subsequent~~ control period.

9VAC5-140-6210. ~~Conditional~~ CO_2 allowance allocations.

A. The department will allocate the Virginia CO_2 Budget Trading Program base budget ~~conditional~~ CO_2 allowances ~~to CO_2 budget sources to be consigned to auction~~ to the Virginia ~~Consignment~~ Auction Account.

B. For allocation years ~~2020~~ 2021 through ~~2031~~ 2030, the Virginia CO_2 Budget Trading Program adjusted budget shall be the maximum number of allowances available for allocation in a given allocation year, except for ~~conditional~~ CO_2 CCR allowances.

C. ~~Conditional allowances allocated for a calendar year will be automatically transferred to the Virginia Consignment Auction Account to be consigned to auction. Following each auction, all conditional allowances sold at the auction will be transferred~~

~~from the Virginia Consignment Auction Account to winning bidders' accounts as CO_2 allowances.~~

~~D. The cost containment reserve (CCR) allocation shall be managed as follows.~~ ~~The~~ In the event that the CCR is triggered during an auction, the department will allocate ~~conditional~~ CO_2 CCR allowances, separate from and additional to the Virginia CO_2 Budget Trading Program base budget set forth in 9VAC5-140-6190 to the Virginia ~~Consignment~~ Auction Account. The CCR allocation is for the purpose of containing the cost of CO_2 allowances. The department will allocate ~~conditional~~ CO_2 CCR allowances as follows:

1. ~~Beginning in calendar year 2020, the department will initially allocate, on a pro rata basis to CO2 budget sources, 2.8 million conditional CO2 CCR allowances.~~

~~2.~~ On or before January 1, 2021, and each year thereafter, the department will allocate~~, on a pro rata basis to CO2 budget sources, current vintage year conditional~~ CO_2 CCR allowances equal to the quantity in Table 140-5A.

Table 140-5A
~~Conditional~~ CO_2 CCR Allowances from 2021 Forward

2021	2.716 million tons
2022	2.632 million tons
2023	2.548 million tons
2024	2.464 million tons
2025	2.380 million tons
2026	2.296 million tons
2027	2.212 million tons
2028	2.128 million tons
2029	2.044 million tons
2030 and each year thereafter	1.960 million tons

~~3. The pro rata calculation to be used for the distribution of conditional CO2 CCR allowances is as follows:~~

~~$SAA/TAA * CCR = SCCR$~~

~~Where:~~

~~SAA = source adjusted allocation~~
~~TAA = total adjusted allocation~~
~~SCCR = source CCR~~

~~4.~~ 2. ~~Conditional~~ CCR allowances allocated for a calendar year will be automatically transferred to the Virginia ~~Consignment~~ Auction Account to be ~~consigned to auction~~ auctioned. Following each auction, all ~~conditional~~ CO_2 CCR allowances sold at auction will be transferred to winning bidders' accounts as CO_2 CCR allowances.

~~5.~~ 3. Unsold ~~conditional~~ CO_2 CCR allowances will remain in the Virginia ~~Consignment~~ Auction Account to be re-offered for sale at auction within the same calendar year. ~~Conditional~~ CO_2 CCR allowances remaining unsold at the end of the calendar year in which they were originated will be made unavailable for sale at future auctions.

~~E.~~ D. In the event that the ECR is triggered during an auction, the department will authorize its agent to withhold ~~conditional~~ CO_2 allowances as needed. The department will further authorize its agent to convert and transfer any ~~conditional~~ CO_2 allowances that have been withheld from any auction into the Virginia ECR account. The ECR withholding is for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs. The department's agent will withhold CO_2 ECR allowances as follows:

1. If the condition in 9VAC5-140-6420 ~~D 1~~ C 1 is met at an auction, then the maximum number of CO_2 ECR allowances that will be withheld from that auction will be equal to the quantity shown in Table 140-5B minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the Virginia ECR account.

Table 140-5B
ECR Allowances from 2021 Forward

2021	2.716 million tons
2022	2.632 million tons
2023	2.548 million tons
2024	2.464 million tons
2025	2.380 million tons
2026	2.296 million tons
2027	2.212 million tons
2028	2.128 million tons
2019	2.044 million tons
2030 and each year thereafter	1.960 million tons

2. Allowances that have been transferred into the Virginia ECR account shall not be withdrawn.

~~F.~~ E. The adjustment for banked allowances will be as follows. On March 15, 2021, the department may determine the adjustment for banked allowances quantity for allocation years 2021 through 2025 through the application of the following formula:

$$TABA = ((TA - TAE)/5) \times RS\%$$

Where:

TABA is the adjustment for banked allowances quantity in tons.

TA, adjustment, is the total quantity of allowances of vintage years prior to 2021 held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program but not including accounts opened by participating states, as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

TAE, adjustment emissions, is the total quantity of 2018, 2019, and 2020 emissions from all CO_2 budget sources in all participating states, reported pursuant to CO_2 Budget Trading Program as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

RS% is Virginia budget divided by the regional budget.

~~G.~~ F. CO_2 Budget Trading Program adjusted budgets for 2021 through 2025 shall be determined as follows: on April 15, 2021, the department will determine the Virginia CO_2 Budget Trading Program adjusted budgets for the 2021 through 2025 allocation years by the following formula:

$$AB = BB - TABA$$

Where:

AB is the Virginia CO_2 Budget Trading Program adjusted budget.

BB is the Virginia CO_2 Budget Trading Program base budget.

TABA is the adjustment for banked allowances quantity in tons.

~~H.~~ G. The department or its agent will publish the CO_2 trading program adjusted budgets for the 2021 through 2025 allocation years.

~~I. Timing requirements for conditional allowance allocations shall be as follows:~~

~~1. By August 25, 2019, the department will submit to its agent the conditional allowance allocations in accordance with 9VAC5-140-6215 A and B, for the initial control period, 2020.~~

~~2. By the month and day established by subdivision 1 of this subsection, 2020, the department will submit to its agent 50% of the conditional allowance allocations in accordance with 9VAC5-140-6215 A and B, for the 2021 control period.~~

~~By the month and day one month before the date established by subdivision 1 of this subsection, 2021, the department will submit to its agent the remainder of the conditional allowance allocations in accordance with 9VAC5-140-6215 A and B, for 2021.~~

~~3. By the month and day established by subdivision 1 of this subsection, 2021, and the month and day established by subdivision 1 of this subsection of every subsequent year thereafter, the department will submit to its agent the conditional allowance allocations for the applicable control period in accordance with 9VAC5-140-6215 A and B.~~

~~J. Implementation of the CCR (subsection C of this section), the ECR (subsection D of this section) and the banking adjustment (subsection E of this section) shall be determined based on the extent of the CO2 trading program.~~

~~K. Conditional allowances and conditional CCR allowances allocated for a calendar year will be automatically transferred to the Virginia Consignment Auction Account to be consigned to auction. Following each auction, all conditional allowances sold at the auction will be transferred from the Virginia Consignment Auction Account to winning bidders' accounts as CO_2 allowances. Conditional CCR allowances sold at auction will be transferred to winning bidders' accounts as CO_2 CCR allowances. Unsold conditional CCR allowances will remain in the Virginia Consignment Auction Account to be re-offered for sale at auction within the same calendar year. Conditional CCR allowances remaining unsold at the end of the calendar year in which they were originated will be made unavailable for sale at future auctions.~~

9VAC5-140-6211. ~~Conditional allowance allocations, DMME allowances.~~ (Repealed.)

~~Notwithstanding 9VAC5-140-6210, the department will allocate 5.0% of the Virginia CO_2 Budget Trading Program base or adjusted budget allowances, as applicable, to DMME to be consigned to auction by the holder of a public contract with DMME to assist the department for the abatement and control of air pollution, specifically CO_2, by the implementation of programs that lower base and peak electricity demand and reduce the cost of the program to consumers and budget sources.~~

9VAC5-140-6215. ~~Conditional allocation methodology.~~ (Repealed.)

~~A. The net electric output in MWh used with respect to conditional allowance allocations under subsection B of this section for each CO_2 budget unit shall be:~~

~~1. For units operating on or before January 1, 2020, the average of the three amounts of the unit's net electric output during 2016, 2017, and 2018 to determine allocations for the initial control period.~~

~~2. For all units operating in each control period after 2020, the average of the three amounts of the unit's total net-electric output during the three most recent years for which data are available prior to the start of the control period.~~

~~B. 1. For each control period beginning in 2020 and thereafter, the department will allocate to all CO_2 budget units that have a net-electric output, as determined under subsection A of this section, a total amount of conditional allowances equal to the CO2 base budget.~~

~~2. The department will allocate conditional allowances to each conditional budget unit under subdivision 1 of this subsection in an amount determined by multiplying the total amount of CO_2 allowances allocated under subdivision 1 of this subsection by the ratio of the baseline electrical output of such CO_2 budget unit to the total amount of baseline electrical output of all such CO_2 budget units and rounding to the nearest whole allowance as appropriate.~~

~~3. New CO_2 budget units will be allocated conditional allowances once they have established electrical output data to be used in the conditional allowance allocation process.~~

~~C. For the purpose of the allocation process as described in subsections A and B of this section, CO_2 budget units shall report the unit's net-electric output to the department on a yearly basis as follows:~~

~~1. By August 25, 2019, each CO_2 budget unit shall report yearly net-electric output data during 2016, 2017, and 2018.~~

~~2. By the month and day established by subdivision 1 of this subsection, 2020, and each year thereafter, each CO_2 budget unit shall report yearly net-electric output data for the previous year.~~

Article 6. CO_2 Allowance Tracking System

9VAC5-140-6220. CO_2 allowance tracking system accounts.

A. Consistent with 9VAC5-140-6230 A, the department or its agent will establish one compliance account for each CO_2 budget source. Allocations of ~~conditional~~ CO_2 allowances pursuant to Article 5 (9VAC5-140-6190 et seq.) of this part and deductions or transfers of ~~conditional~~ CO_2 allowances pursuant to 9VAC5-140-6180, 9VAC5-140-6260, 9VAC5-140-6280, or Article 7 (9VAC5-140-6300 et seq.) of this part will be recorded in the compliance accounts in accordance with this section.

B. Consistent with 9VAC5-140-6230 B, the department or its agent will establish, upon request, a general account for any person. Transfers of CO_2 allowances pursuant

to Article 7 (9VAC5-140-6300 et seq.) of this part will be recorded in the general account in accordance with this article.

9VAC5-140-6230. Establishment of accounts.

A. Upon receipt of a complete account certificate of representation under 9VAC5-140-6110, the department or its agent will establish ~~a conditional~~ an allowance account and a compliance account for each CO_2 budget source for which an account certificate of representation was submitted ~~and a conditional allowance account for DMME~~.

B. General accounts shall operate as follows.

1. Any person may apply to open a general account for the purpose of holding and transferring CO_2 allowances. An application for a general account may designate one and only one CO_2 authorized account representative and one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative. A complete application for a general account shall be submitted to the department or its agent and shall include the following elements in a format prescribed by the department or its agent:

a. Name, address, email address, telephone number, and facsimile transmission number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

b. At the option of the CO_2 authorized account representative, organization name and type of organization;

c. A list of all persons subject to a binding agreement for the CO_2 authorized account representative or any CO_2 authorized alternate account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

d. The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: "I certify that I was selected as the CO_2 authorized account representative or the CO_2 authorized alternate account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the department or its agent or a court regarding the general account.";

e. The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed; and

f. Unless otherwise required by the department or its agent, documents of agreement referred to in the application for a general account shall not be submitted to the department or its agent. Neither the department nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

2. Authorization of the CO_2 authorized account representative shall be as follows:

a. Upon receipt by the department or its agent of a complete application for a general account under subdivision 1 of this subsection:

(1) The department or its agent will establish a general account for the person for whom the application is submitted.

(2) The CO_2 authorized account representative and any CO_2 authorized alternate account representative for the general account shall represent and, by his representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative or any CO_2 authorized alternate account representative and such person. Any such person shall be bound by any order or decision issued to the CO_2 authorized account representative or any CO_2 authorized alternate account representative by the department or its agent or a court regarding the general account.

(3) Any representation, action, inaction, or submission by any CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

b. Each submission concerning the general account shall be submitted, signed, and certified by the CO_2 authorized account representative or any CO_2 authorized alternate account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission shall include the following certification statement by the CO_2 authorized account representative or any CO_2 authorized alternate account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry

of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

c. The department or its agent will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with subdivision 2 b of this subsection.

3. Changing CO_2 authorized account representative and CO_2 authorized alternate account representative, and changes in persons with ownership interest, shall be accomplished as follows:

a. The CO_2 authorized account representative for a general account may be changed at any time upon receipt by the department or its agent of a superseding complete application for a general account under subdivision 1 of this subsection. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the department or its agent receives the superseding application for a general account shall be binding on the new CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

b. The CO_2 authorized alternate account representative for a general account may be changed at any time upon receipt by the department or its agent of a superseding complete application for a general account under subdivision 1 of this subsection. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the department or its agent receives the superseding application for a general account shall be binding on the new alternate CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

c. In the event a new person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative, and the decisions, orders, actions, and inactions of the department or its agent, as if the new person were included in such list.

d. Within 30 days following any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or deletion of persons, the CO_2 authorized account representative or any CO_2 authorized alternate account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CO_2 allowances in the general account to include the change.

4. Objections concerning CO_2 authorized account representative shall be governed as follows:

a. Once a complete application for a general account under subdivision 1 of this subsection has been submitted and received, the department or its agent will rely on the application unless and until a superseding complete application for a general account under subdivision 1 of this subsection is received by the department or its agent.

b. Except as provided in subdivisions 3 a and 3 b of this subsection, no objection or other communication submitted to the department or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative or the finality of any decision or order by the department or its agent under the CO_2 Budget Trading Program.

c. Neither the department nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

5. Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative shall be accomplished as follows:

a. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent provided for under this article and Article 7 (9VAC5-140-6300 et seq.) of this part.

b. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent provided for under this article and Article 7 (9VAC5-140-6300 et seq.) of this part.

c. To delegate authority to make an electronic submission to the department or its agent in accordance with subdivisions 5 a and 5 b of this subsection, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

(1) The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(2) The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as "electronic submission agent";

(3) For each such natural person, a list of the type of electronic submissions under subdivision 5 c (1) or 5 c (2) of this subsection for which authority is delegated to him; and

(4) The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any electronic submission to the department or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6230 B 5 d shall be deemed to be an electronic submission by me. Until this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6230 B 5 d, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under 9VAC5-140-6230 B 5 is terminated."

d. A notice of delegation submitted under subdivision 5 c of this subsection shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

e. Any electronic submission covered by the certification in subdivision 5 c (4) of this subsection and made in accordance with a notice of delegation effective under subdivision 5 d of this subsection shall be deemed to be an

electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

C. The department or its agent will assign a unique identifying number to each account established under subsection A or B of this section.

9VAC5-140-6240. CO_2 allowance tracking system responsibilities of CO_2 authorized account representative.

Following the establishment of a COATS account, all submissions to the department or its agent pertaining to the account, including submissions concerning the deduction or transfer of CO_2 allowances in the account, shall be made only by the CO_2 authorized account representative for the account.

9VAC5-140-6250. Recordation of ~~conditional~~ CO_2 allowance allocations.

A. By January 1 of each calendar year, the department or its agent will record in the following accounts:

1. In each CO_2 budget source's ~~and DMME's conditional~~ allowance account, the ~~conditional~~ CO_2 allowances allocated to those sources ~~and DMME~~ by the department prior to being ~~consigned to auction~~ auctioned; and

2. In each CO_2 budget source's compliance account, the ~~CO_2~~ allowances purchased at auction by CO_2 budget units at the source under 9VAC5-140-6210 A.

B. Each year the department or its agent will record ~~conditional~~ CO_2 allowances, as allocated to the unit under Article 5 (9VAC5-140-6190 et seq.) of this part, in the compliance account for the year after the last year for which ~~conditional~~ CO_2 allowances were previously allocated to the compliance account. Each year, the department or its agent will also record ~~conditional~~ CO_2 allowances, as allocated under Article 5 (9VAC5-140-6190 et seq.) of this part, in an allocation set-aside for the year after the last year for which ~~conditional~~ CO_2 allowances were previously allocated to an allocation set-aside.

C. Serial numbers for allocated ~~conditional~~ CO_2 allowances shall be managed as follows. When allocating ~~conditional~~ CO_2 allowances to and recording them in an account, the department or its agent will assign each ~~conditional~~ CO_2 allowance a unique identification number that will include digits identifying the year for which the ~~conditional~~ CO_2 allowance is allocated.

9VAC5-140-6260. Compliance.

A. CO_2 allowances that meet the following criteria are available to be deducted for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for ~~the initial control period,~~ a control period , or an interim control period.

1. The CO_2 allowances are of allocation years that fall within ~~an initial control period,~~ a prior control period, the same control period, or the same interim control period for which the allowances will be deducted.

2. The CO_2 allowances are held in the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that ~~initial control period,~~ control period , or interim control period or are transferred into the compliance account by a CO_2 allowance transfer correctly submitted for recordation under 9VAC5-140-6300 by the CO_2 allowance transfer deadline for that ~~initial control period,~~ control period , or interim control period.

3. For CO_2 offset allowances generated by other participating states, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an ~~initial~~ interim control period shall not exceed 3.3% of the CO_2 budget source's CO_2 emissions for that control period, or may not exceed 3.3% of 0.50 times the CO_2 budget source's CO_2 emissions for an interim control period, as determined in accordance with this article and Article 8 (9VAC5-140-6330 et seq.) of this part.

4. The CO_2 allowances are not necessary for deductions for excess emissions for a prior ~~initial control period or a~~ control period under subsection D of this section.

B. Following the recordation, in accordance with 9VAC5-140-6310, of CO_2 allowance transfers submitted for recordation in the CO_2 budget source's compliance account by the CO_2 allowance transfer deadline for ~~the initial control period,~~ a control period , or an interim control period, the department or its agent will deduct CO_2 allowances available under subsection A of this section to cover the source's CO_2 emissions, as determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, for the ~~initial control period,~~ control period , or interim control period, as follows:

1. Until the amount of CO_2 allowances deducted equals the number of tons of total CO_2 emissions, or 0.50 times the number of tons of total CO_2 emissions for an interim control period, determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, from all CO_2 budget units at the CO_2 budget source for the ~~initial control period,~~ control period , or interim control period; or

2. If there are insufficient CO_2 allowances to complete the deductions in subdivision 1 of this subsection, until no more CO_2 allowances available under subsection A of this section remain in the compliance account.

C. Identification of available CO_2 allowances by serial number and default compliance deductions shall be managed as follows:

1. The CO_2 authorized account representative for a source's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for ~~the initial control period,~~ a control period ~~,~~ or interim control period in accordance with subsection B or D of this section. Such identification shall be made in the compliance certification report submitted in accordance with 9VAC5-140-6170.

2. The department or its agent will deduct CO_2 allowances for ~~the initial control period,~~ an interim control period ~~,~~ or a control period from the CO_2 budget source's compliance account, in the absence of an identification or in the case of a partial identification of available CO_2 allowances by serial number under subdivision 1 of this subsection, as follows: Any CO_2 allowances that are available for deduction under subdivision 1 of this subsection. CO_2 allowances shall be deducted in chronological order (i.e., CO_2 allowances from earlier allocation years shall be deducted before CO_2 allowances from later allocation years). In the event that some, but not all, CO_2 allowances from a particular allocation year are to be deducted, CO_2 allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances.

D. Deductions for excess emissions shall be managed as follows.

1. After making the deductions for compliance under subsection B of this section, the department or its agent will deduct from the CO_2 budget source's compliance account a number of CO_2 allowances equal to three times the number of the source's excess emissions. In the event that a source has insufficient CO_2 allowances to cover three times the number of the source's excess emissions, the source shall be required to immediately transfer sufficient allowances into its compliance account.

2. Any CO_2 allowance deduction required under subdivision 1 of this subsection shall not affect the liability of the owners and operators of the CO_2 budget source or the CO_2 budget units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under applicable state law. The following guidelines will be followed in assessing fines, penalties, or other obligations:

a. For purposes of determining the number of days of violation, if a CO_2 budget source has excess emissions for a control period, each day in the control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

b. Each ton of excess emissions is a separate violation.

c. For purposes of determining the number of days of violation, if a CO_2 budget source has excess interim emissions for an interim control period, each day in the interim control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

d. Each ton of excess interim emissions is a separate violation.

3. The propriety of the department's determination that a CO_2 budget source had excess emissions and the concomitant deduction of CO_2 allowances from that CO_2 budget source's account may be later challenged in the context of the initial administrative enforcement, or any civil or criminal judicial action arising from or encompassing that excess emissions violation. The commencement or pendency of any administrative enforcement, or civil or criminal judicial action arising from or encompassing that excess emissions violation will not act to prevent the department or its agent from initially deducting the CO_2 allowances resulting from the department's original determination that the relevant CO_2 budget source has had excess emissions. Should the department's determination of the existence or extent of the CO_2 budget source's excess emissions be revised either by a settlement or final conclusion of any administrative or judicial action, the department will act as follows:

a. In any instance where the department's determination of the extent of excess emissions was too low, the department will take further action under subdivisions 1 and 2 of this subsection to address the expanded violation.

b. In any instance where the department's determination of the extent of excess emissions was too high, the department will distribute to the relevant CO_2 budget source a number of CO_2 allowances equaling the number of CO_2 allowances deducted which are attributable to the difference between the original and final quantity of excess emissions. Should such CO_2 budget source's compliance account no longer exist, the CO_2 allowances will be provided to a general account selected by the owner or operator of the CO_2 budget source from which they were originally deducted.

E. The department or its agent will record in the appropriate compliance account all deductions from such an account pursuant to subsections B and D of this section.

F. Action by the department on submissions shall be as follows:

1. The department may review and conduct independent audits concerning any submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the submissions.

2. The department may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on information in the submissions, as adjusted under subdivision 1 of this subsection.

9VAC5-140-6270. Banking.

Each CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under 9VAC5-140-6180, 9VAC5-140-6260, 9VAC5-140-6280, or Article 7 (9VAC5-140-6300 et seq.) of this part.

9VAC5-140-6280. Account error.

The department or its agent may, at its sole discretion and on its own motion, correct any error in any COATS account. Within 10 business days of making such correction, the department or its agent will notify the CO_2 authorized account representative for the account.

9VAC5-140-6290. Closing of general accounts.

A. A CO_2 authorized account representative of a general account may instruct the department or its agent to close the account by submitting a statement requesting deletion of the account from the COATS and by correctly submitting for recordation under 9VAC5-140-6300 a CO_2 allowance transfer of all CO_2 allowances in the account to one or more other COATS accounts.

B. If a general account shows no activity for a period of one year or more and does not contain any CO_2 allowances, the department or its agent may notify the CO_2 authorized account representative for the account that the account will be closed in the COATS 30 business days after the notice is sent. The account will be closed after the 30-day period unless before the end of the 30-day period the department or its agent receives a correctly submitted transfer of CO_2 allowances into the account under 9VAC5-140-6300 or a statement submitted by the CO_2 authorized account representative demonstrating to the satisfaction of the department or its agent good cause as to why the account should not be closed. The department or its agent will have sole discretion to determine if the owner or operator of the unit demonstrated that the account should not be closed.

Article 7. CO_2 Allowance Transfers

9VAC5-140-6300. Submission of CO_2 Allowance Transfers.

The CO_2 authorized account representatives seeking recordation of a CO_2 allowance transfer shall submit the transfer to the department or its agent. To be

considered correctly submitted, the CO_2 allowance transfer shall include the following elements in a format specified by the department or its agent:

1. The numbers identifying both the transferor and transferee accounts;

2. A specification by serial number of each CO_2 allowance to be transferred;

3. The printed name and signature of the CO_2 authorized account representative of the transferor account and the date signed;

4. The date of the completion of the last sale or purchase transaction for the allowance, if any; and

5. The purchase or sale price of the allowance that is the subject of a sale or purchase transaction under subdivision 4 of this section.

9VAC5-140-6310. Recordation.

A. Within five business days of receiving a CO_2 allowance transfer, except as provided in subsection B of this section, the department or its agent will record a CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified by the request, provided that:

1. The transfer is correctly submitted under 9VAC5-140-6300; and

2. The transferor account includes each CO_2 allowance identified by serial number in the transfer.

B. A CO_2 allowance transfer into or out of a compliance account that is submitted for recordation following the CO_2 allowance transfer deadline and that includes any CO_2 allowances that are of allocation years that fall within a control period prior to or the same as the control period to which the CO_2 allowance transfer deadline applies will not be recorded until after completion of the process pursuant to 9VAC5-140-6260 B.

C. Where a CO_2 allowance transfer submitted for recordation fails to meet the requirements of subsection A of this section, the department or its agent will not record such transfer.

9VAC5-140-6320. Notification.

A. Within five business days of recordation of a CO_2 allowance transfer under 9VAC5-140-6310 , the department or its agent will notify each party to the transfer. Notice will be given to the CO_2 authorized account representatives of both the transferor and transferee accounts.

B. Within 10 business days of receipt of a CO_2 allowance transfer that fails to meet the requirements of 9VAC5-140-6310 A, the department or its agent will notify the CO_2 authorized account representatives of both accounts subject to the transfer of (i) a decision not to record the transfer and (ii) the reasons for such nonrecordation.

C. Nothing in this section shall preclude the submission of a CO_2 allowance transfer for recordation following notification of nonrecordation.

9VAC5-140-6325. Life-of-the-unit contractual arrangements.

A. A power purchaser entered into a life-of-the-unit contractual arrangement as described in subdivision b of the definition of "life-of-the-unit contractual arrangement" with a CO_2 budget source or unit shall be responsible for acquiring and transferring all allowances to the CO_2 budget source or unit that are necessary for demonstrating compliance with the CO_2 budget trading program.

B. The CO_2 budget source or unit shall provide a copy of the energy conversion or energy tolling agreement to the department within six months of the effective date of this part. If such agreement is subject to third-party disclosure restrictions, the CO_2 budget source or unit shall provide purchaser with 10 days prior written notice of its intention to disclose the agreement to the department and request confidential treatment from the public disclosure of such agreement. The department will grant a request for confidential treatment pursuant to applicable statutory and regulatory requirements addressing confidential information.

C. The CO_2 budget source or unit shall be responsible for compliance with and otherwise be subject to all other requirements of this part and the CO_2 budget trading program.

Article 8. Monitoring, Reporting, and Recordkeeping

9VAC5-140-6330. General requirements.

A. The owners and operators, and to the extent applicable, the CO_2 authorized account representative of a CO_2 budget unit shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this section and all applicable sections of 40 CFR Part 75. Where referenced in this article, the monitoring requirements of 40 CFR Part 75 shall be adhered to in a manner consistent with the purpose of monitoring and reporting CO_2 mass emissions pursuant to this part. For purposes of complying with such requirements, the definitions in 9VAC5-140-6020 and in 40 CFR 72.2 shall apply, and the terms "affected unit," "designated representative," and "CEMS" in 40 CFR Part 75 shall be replaced by the terms "CO_2 budget unit," "CO_2 authorized account representative," and "CEMS," respectively, as defined in 9VAC5-140-6020. For units not subject to an ~~acid rain~~ Acid Rain emissions limitation, the term

"administrator" in 40 CFR Part 75 shall be replaced with "the department or its agent." Owners or operators of a CO_2 budget unit who monitor a non-CO_2 budget unit pursuant to the common, multiple, or bypass stack procedures in 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16 (b)(2)(ii)(B) pursuant to 40 CFR 75.13, for purposes of complying with this part, shall monitor and report CO_2 mass emissions from such non-CO_2 budget units according to the procedures for CO_2 budget units established in this article.

B. The owner or operator of each CO_2 budget unit shall meet the following general requirements for installation, certification, and data accounting.

1. Install all monitoring systems necessary to monitor CO_2 mass emissions in accordance with 40 CFR Part 75, except for equation G-1. Equation G-1 in Appendix G shall not be used to determine CO_2 emissions under this part. This may require systems to monitor CO_2 concentration, stack gas flow rate, O_2 concentration, heat input, and fuel flow rate.

2. Successfully complete all certification tests required under 9VAC5-140-6340 and meet all other requirements of this section and 40 CFR Part 75 applicable to the monitoring systems under subdivision 1 of this subsection.

3. Record, report, and quality-assure the data from the monitoring systems under subdivision 1 of this subsection.

C. The owner or operator shall meet the monitoring system certification and other requirements of subsection B of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under subdivision B 1 of this section on and after the following dates:

1. The owner or operator of a CO_2 budget unit, except for a CO_2 budget unit under subdivision 2 of this subsection, shall comply with the requirements of this section by January 1, ~~2020~~ 2021.

2. The owner or operator of a CO_2 budget unit that commences commercial operation July 1, ~~2020~~ 2021, shall comply with the requirements of this section by (i) January 1, ~~2021~~ 2022, or (ii) the earlier of 90 unit operating days after the date on which the unit commences commercial operation or 180 calendar days after the date on which the unit commences commercial operation.

3. For the owner or operator of a CO_2 budget unit for which construction of a new stack or flue installation is completed after the applicable deadline under subdivision 1 or 2 of this subsection by the earlier of (i) 90 unit operating days after the date on which emissions first exit to the atmosphere through the new stack or flue or (ii) 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue.

D. Data shall be reported as follows:

1. Except as provided in subdivision 2 of this subsection, the owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in subsection C of this section for any monitoring system under subdivision B 1 of this section shall, for each such monitoring system, determine, record, and report maximum potential, or as appropriate minimum potential, values for CO_2 concentration, CO_2 emissions rate, stack gas moisture content, fuel flow rate, heat input, and any other parameter required to determine CO_2 mass emissions in accordance with 40 CFR 75.31(b)(2) or (c)(3) or Section 2.4 of Appendix D of 40 CFR Part 75 as applicable.

2. The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in subdivision C 3 of this section for any monitoring system under subdivision B 1 of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in Subpart D, or Appendix D of 40 CFR Part 75, in lieu of the maximum potential, or as appropriate minimum potential, values for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under subdivision C 3 of this section.

a. CO_2 budget units subject to an ~~acid rain~~ Acid Rain emissions limitation or CSAPR NO_x Ozone Season Trading Program that qualify for the optional SO_2, NO_x, and CO_2 (for ~~acid rain~~ Acid Rain) or NO_x (for CSAPR NO_x Ozone Season Trading Program) emissions calculations for low mass emissions (LME) units under 40 CFR 75.19 and report emissions for such programs using the calculations under 40 CFR 75.19, shall also use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

b. CO_2 budget units subject to an ~~acid rain~~ Acid Rain emissions limitation that do not qualify for the optional SO_2, NO_x, and CO_2 (for ~~acid rain~~ Acid Rain) or NO_x (for CSAPR NO_x Ozone Season Trading Program) emissions calculations for LME units under 40 CFR 75.19 shall not use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

c. CO_2 budget units not subject to an ~~acid rain~~ Acid Rain emissions limitation shall qualify for the optional CO_2 emissions calculation for LME units under 40 CFR 75.19, provided that they emit less than 100 tons of NO_x annually and no more than 25 tons of SO_2 annually.

3. The owner or operator of a CO_2 budget unit shall report net-electric output data to the department as required by Article 5 (9VAC5-140-6190 et seq.) of this part.

E. Prohibitions shall be as follows.

1. No owner or operator of a CO_2 budget unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required CEMS without having obtained prior written approval in accordance with 9VAC5-140-6380.

2. No owner or operator of a CO_2 budget unit shall operate the unit so as to discharge, or allow to be discharged, CO_2 emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this article and 40 CFR Part 75.

3. No owner or operator of a CO_2 budget unit shall disrupt the CEMS, any portion thereof, or any other approved emissions monitoring method, and thereby avoid monitoring and recording CO_2 mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this article and 40 CFR Part 75.

4. No owner or operator of a CO_2 budget unit shall retire or permanently discontinue use of the CEMS, any component thereof, or any other approved emissions monitoring system under this article, except under any one of the following circumstances:

a. The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this article and 40 CFR Part 75, by the department for use at that unit that provides emissions data for the same pollutant or parameter as the retired or discontinued monitoring system; or

b. The CO_2 authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with 9VAC5-140-6340 D 3 a.

9VAC5-140-6340. Initial certification and recertification procedures.

A. The owner or operator of a CO_2 budget unit shall be exempt from the initial certification requirements of this section for a monitoring system under 9VAC5-140-6330 B 1 if the following conditions are met:

1. The monitoring system has been previously certified in accordance with 40 CFR Part 75; and

2. The applicable quality-assurance and quality-control requirements of 40 CFR 75.21 and Appendix B and Appendix D of 40 CFR Part 75 are fully met for the certified monitoring system described in subdivision 1 of this subsection.

B. The recertification provisions of this section shall apply to a monitoring system under 9VAC5-140-6330 B 1 exempt from initial certification requirements under subsection A of this section.

C. Notwithstanding subsection A of this section, if the administrator has previously approved a petition under 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16(b)(2)(ii)(B) as pursuant to 40 CFR 75.13 for apportioning the CO_2 emissions rate measured in a common stack or a petition under 40 CFR 75.66 for an alternative requirement in 40 CFR Part 75, the CO_2 authorized account representative shall submit the petition to the department under 9VAC5-140-6380 A to determine whether the approval applies under this program.

D. Except as provided in subsection A of this section, the owner or operator of a CO_2 budget unit shall comply with the following initial certification and recertification procedures for a CEMS and an excepted monitoring system under Appendix D of 40 CFR Part 75 and under 9VAC5-140-6330 B 1. The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology in 40 CFR 75.19 or that qualifies to use an alternative monitoring system under Subpart E of 40 CFR Part 75 shall comply with the procedures in subsection E or F of this section, respectively.

1. For initial certification, the owner or operator shall ensure that each CEMS required under 9VAC5-140-6330 B 1, which includes the automated DAHS, successfully completes all of the initial certification testing required under 40 CFR 75.20 by the applicable deadlines specified in 9VAC5-140-6330 C. In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this article in a location where no such monitoring system was previously installed, initial certification in accordance with 40 CFR 75.20 is required.

2. For recertification, the following requirements shall apply.

a. Whenever the owner or operator makes a replacement, modification, or change in a certified CEMS under 9VAC5-140-6330 B 1 that the administrator or the department determines significantly affects the ability of the system to accurately measure or record CO_2 mass emissions or to meet the quality-assurance and quality-control requirements of 40 CFR 75.21 or Appendix B to 40 CFR Part 75, the owner or operator shall recertify the monitoring system according to 40 CFR 75.20(b).

b. For systems using stack measurements such as stack flow, stack moisture content, CO_2 or O_2 monitors, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the administrator or the department determines to significantly change the flow or concentration profile, the owner or operator shall recertify the CEMS according to 40 CFR 75.20(b). Examples of changes that require recertification include

replacement of the analyzer, change in location or orientation of the sampling probe or site, or change of flow rate monitor polynomial coefficients.

3. The approval process for initial certifications and recertification shall be as follows: subdivisions 3 a through 3 d of this subsection apply to both initial certification and recertification of a monitoring system under 9VAC5-140-6330 B 1. For recertifications, replace the words "certification" and "initial certification" with the word "recertification," replace the word "certified" with "recertified," and proceed in the manner prescribed in 40 CFR 75.20(b)(5) and (g)(7) in lieu of subdivision 3 e of this subsection.

a. The CO_2 authorized account representative shall submit to the department or its agent, the appropriate EPA Regional Office and the administrator a written notice of the dates of certification in accordance with 9VAC5-140-6360.

b. The CO_2 authorized account representative shall submit to the department or its agent a certification application for each monitoring system. A complete certification application shall include the information specified in 40 CFR 75.63.

c. The provisional certification date for a monitor shall be determined in accordance with 40 CFR 75.20(a)(3). A provisionally certified monitor may be used under the CO_2 Budget Trading Program for a period not to exceed 120 days after receipt by the department of the complete certification application for the monitoring system or component thereof under subdivision 3 b of this subsection. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of 40 CFR Part 75, will be considered valid quality assured data, retroactive to the date and time of provisional certification, provided that the department does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the department.

d. The department will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under subdivision 3 b of this subsection. In the event the department does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of 40 CFR Part 75 and is included in the certification application will be deemed certified for use under the CO_2 Budget Trading Program.

(1) If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR Part 75, then the department will issue a written notice of approval of the certification application within 120 days of receipt.

(2) If the certification application is incomplete, then the department will issue a written notice of incompleteness that sets a reasonable date by which the CO_2 authorized account representative shall submit the additional information required to complete the certification application. If the CO_2 authorized account representative does not comply with the notice of incompleteness by the specified date, then the department may issue a notice of disapproval under subdivision 3 d (3) of this subsection. The 120-day review period shall not begin before receipt of a complete certification application.

(3) If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of 40 CFR Part 75, or if the certification application is incomplete and the requirement for disapproval under subdivision 3 d (2) of this subsection is met, then the department will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the department and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in subdivision 3 e of this subsection for each monitoring system or component thereof, which is disapproved for initial certification.

(4) The department may issue a notice of disapproval of the certification status of a monitor in accordance with 9VAC5-140-6350 B.

e. If the department issues a notice of disapproval of a certification application under subdivision 3 d (3) of this subsection or a notice of disapproval of certification status under subdivision 3 d (3) of this subsection, then:

(1) The owner or operator shall substitute the following values for each disapproved monitoring system, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under 40 CFR 75.20(a)(5)(i) or 40 CFR 75.20(g)(7): (i) for units using or intending to monitor for CO_2 mass emissions using heat input or for units sing the low mass emissions excepted methodology under 40 CFR 75.19, the maximum potential hourly heat input of the unit; or (ii) for units intending to monitor for CO_2 mass emissions using a CO_2 pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO_2 and the maximum potential flow rate of the unit under Section 2.1 of Appendix A of 40 CFR Part 75;

(2) The CO_2 authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with subdivisions 3 a and 3 b of this subsection; and

(3) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the department's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

E. The owner or operator of a unit qualified to use the low mass emissions excepted methodology under 9VAC5-140-6330 D 3 shall meet the applicable certification and recertification requirements of 40 CFR 75.19(a)(2), 40 CFR 75.20(h), and this section. If the owner or operator of such a unit elects to certify a fuel flow meter system for heat input determinations, the owner or operator shall also meet the certification and recertification requirements in 40 CFR 75.20(g).

F. The CO_2 authorized account of each unit for which the owner or operator intends to use an alternative monitoring system approved by the administrator and, if applicable, the department under Subpart E of 40 CFR Part 75 shall comply with the applicable notification and application procedures of 40 CFR 75.20(f).

9VAC5-140-6350. Out-of-control periods.

A. Whenever any monitoring system fails to meet the quality assurance/quality control (QA/QC) requirements or data validation requirements of 40 CFR Part 75, data shall be substituted using the applicable procedures in Subpart D or Appendix D of 40 CFR Part 75.

B. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under 9VAC5-140-6340 or the applicable provisions of 40 CFR Part 75, both at the time of the initial certification or recertification application submission and at the time of the audit, the department or administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this subsection, an audit shall be either a field audit or an audit of any information submitted to the department or the administrator. By issuing the notice of disapproval, the department or administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the initial certification or recertification procedures in 9VAC5-140-6340 for each disapproved monitoring system.

9VAC5-140-6360. Notifications.

The CO_2 authorized account representative for a CO_2 budget unit shall submit written notice to the department and the administrator in accordance with 40 CFR 75.61.

9VAC5-140-6370. Recordkeeping and reporting.

A. The CO_2 authorized account representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under 40 CFR 75.73, and the requirements of 9VAC5-140-6080 E.

B. The owner or operator of a CO_2 budget unit shall submit a monitoring plan in the manner prescribed in 40 CFR 75.62.

C. The CO_2 authorized account representative shall submit an application to the department within 45 days after completing all CO_2 monitoring system initial certification or recertification tests required under 9VAC5-140-6340 , including the information required under 40 CFR 75.63 and 40 CFR 75.53(e) and (f).

D. The CO_2 authorized account representative shall submit quarterly reports, as follows:

1. The CO_2 authorized account representative shall report the CO_2 mass emissions data for the CO_2 budget unit, in an electronic format prescribed by the department unless otherwise prescribed by the department for each calendar quarter.

2. The CO_2 authorized account representative shall submit each quarterly report to the department or its agent within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in Subpart H of 40 CFR Part 75 and 40 CFR 75.64. Quarterly reports shall be submitted for each CO_2 budget unit, or group of units using a common stack, and shall include all of the data and information required in Subpart G of 40 CFR Part 75, except for opacity, heat input, NO_x, and SO_2 provisions.

3. The CO_2 authorized account representative shall submit to the department or its agent a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

a. The monitoring data submitted were recorded in accordance with the applicable requirements of this article and 40 CFR Part 75, including the quality assurance procedures and specifications;

b. For a unit with add-on CO_2 emissions controls and for all hours where data are substituted in accordance with 40 CFR 75.34(a)(1), the add-on emissions controls were operating within the range of parameters listed in the QA/QC program under Appendix B of 40 CFR Part 75 and the substitute values do not systematically underestimate CO_2 emissions; and

c. The CO_2 concentration values substituted for missing data under Subpart D of 40 CFR Part 75 do not systematically underestimate CO_2 emissions.

9VAC5-140-6380. Petitions.

A. Except as provided in subsection C of this section, the CO_2 authorized account representative of a CO_2 budget unit that is subject to an ~~acid rain~~ Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this article only to the extent that the petition is approved in writing by the administrator, and subsequently approved in writing by the department.

B. Petitions for a CO_2 budget unit that is not subject to an ~~acid rain~~ Acid Rain emissions limitation shall meet the following requirements.

1. The CO_2 authorized account representative of a CO_2 budget unit that is not subject to an ~~acid rain~~ Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this article only to the extent that the petition is approved in writing by the administrator and subsequently approved in writing by the department.

2. In the event that the administrator declines to review a petition under subdivision 1 of this subsection, the CO_2 authorized account representative of a CO_2 budget unit that is not subject to an ~~acid rain~~ Acid Rain emissions limitation may submit a petition to the department requesting approval to apply an alternative to any requirement of this article. That petition shall contain all of the relevant information specified in 40 CFR 75.66. Application of an alternative to any requirement of this article is in accordance with this article only to the extent that the petition is approved in writing by the department.

C. The CO_2 authorized account representative of a CO_2 budget unit that is subject to an ~~acid rain~~ Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of 40 CFR 75.72 or a CO_2 concentration CEMS used under 40 CFR 75.71(a)(2). Application of an alternative to any such requirement is in

accordance with this article only to the extent the petition is approved in writing by the administrator and subsequently approved in writing by the department.

9VAC5-140-6390. (Reserved.)

9VAC5-140-6400. (Reserved.)

Article 9. Auction of CO_2 CCR and ECR Allowances

9VAC5-140-6410. Purpose.

The following requirements shall apply to each allowance auction. The department or its agent may specify additional information in the auction notice for each auction. Such additional information may include the time and location of the auction, auction rules, registration deadlines, and any additional information deemed necessary or useful.

9VAC5-140-6420. General requirements.

A. The department's agent will include the following information in the auction notice for each auction:

1. The number of ~~conditional~~ CO_2 allowances offered for sale at the auction, not including any ~~conditional~~ CO_2 CCR allowances;

2. The number of ~~conditional~~ CO_2 CCR allowances that will be offered for sale at the auction if the condition of subdivision B 1 of this section is met;

3. The minimum reserve price for the auction;

4. The CCR trigger price for the auction;

5. The maximum number of ~~conditional~~ CO_2 allowances that may be withheld from sale at the auction if the condition of subdivision D 1 of this section is met; and

6. The ECR trigger price for the auction.

B. The department's agent will follow these rules for the sale of ~~conditional~~ CO_2 CCR allowances.

1. ~~Conditional~~ CO_2 CCR allowances shall only be sold at an auction in which total demand for allowances, above the CCR trigger price, exceeds the number of ~~conditional~~ CO_2 allowances available for purchase at the auction, not including any ~~conditional~~ CO_2 CCR allowances.

2. If the condition of subdivision 1 of this subsection is met at an auction, then the number of ~~conditional~~ CO_2 CCR allowances offered for sale by the department or its agent at the auction shall be equal to the number of ~~conditional~~ CO_2 CCR allowances in the Virginia ~~Consignment~~ Auction Account at the time of the auction.

3. After all of the ~~conditional~~ CO_2 CCR allowances in the Virginia ~~Consignment~~ Auction Account have been sold in a given calendar year, no additional ~~conditional~~ CO_2 CCR allowances will be sold at any auction for the remainder of that calendar year, even if the condition of subdivision 1 of this subsection is met at an auction.

4. At an auction in which ~~conditional~~ CO_2 CCR allowances are sold, the reserve price for the auction shall be the CCR trigger price.

5. If the condition of subdivision 1 of this subsection is not satisfied, no ~~conditional~~ CO_2 CCR allowances shall be offered for sale at the auction, and the reserve price for the auction shall be equal to the minimum reserve price.

C. The department's agent shall implement the reserve price as follows: (i) no allowances shall be sold at any auction for a price below the reserve price for that auction and (ii) if the total demand for allowances at an auction is less than or equal to the total number of allowances made available for sale in that auction, then the auction clearing price for the auction shall be the reserve price.

D. The department's agent will meet the following rules for the withholding of CO_2 ECR allowances from an auction.

1. CO_2 ECR allowances shall only be withheld from an auction if the demand for allowances would result in an auction clearing price that is less than the ECR trigger price prior to the withholding from the auction of any ECR allowances.

2. If the condition in subdivision 1 of this subsection is met at an auction, then the maximum number of CO_2 ECR allowances that may be withheld from that auction will be equal to the quantity shown in Table 140-5B of 9VAC5-140-6210 E minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the Virginia ECR Account.

9VAC5-140-6430. ~~Consignment auction.~~ (Repealed.)

~~In accordance with Article 5 (9VAC5-140-6190 et seq.) of this part, one quarter of the annual conditional allowance allocation shall be consigned by the CO_2 budget source to whom they are allocated or the holder of a public contract with DMME to each auction in accordance with procedures specified by the department. At the~~

~~completion of the consignment auction, a conditional allowance sold at auction shall become a CO_2 allowance.~~

9VAC5-140-6435. ~~Other auction~~. (Repealed.)

~~Notwithstanding the requirements of 9VAC5-140-6430 , the department may participate in a direct auction of allowances without consignment in accordance with requirements established by the Virginia General Assembly. A "direct auction" means a CO_2 auction conducted by a CO_2 Budget Trading Program in which Virginia is a participating state.~~

Article 10. Program Monitoring and Review

9VAC5-140-6440. Program monitoring and review.

In conjunction with the CO_2 Budget Trading Program program monitoring and review process, the department will evaluate impacts of the program specific to Virginia, including economic, energy, and environmental impacts and impacts on vulnerable and environmental justice and underserved communities. The department will, in evaluating the impacts on environmental justice communities, including low income, minority, and tribal communities, develop and implement a plan to ensure increased participation of environmental justice communities in the review.

Form: TH-09
April 2020

townhall.virginia.gov

Exempt Action: Final Regulation
Agency Background Document

Agency name	Department of Environmental Quality for State Air Pollution Control Board
Virginia Administrative Code (VAC) Chapter citation(s)	Part VII of 9VAC5-140
VAC Chapter title(s)	Regulation for Emissions Trading
Action title	Amend CO_2 Budget Trading Program to comport with RGGI Model Rule as required by Chapter 1219, 2020 Acts of Assembly (Revision A20).
Final agency action date	
Date this document prepared	

Although a regulatory action may be exempt from executive branch review pursuant to § 2.2-4002 or § 2.2-4006 of the *Code of Virginia*, the agency is still encouraged to provide information to the public on the Regulatory Town Hall using this form. However, the agency may still be required to comply with the Virginia Register Act, Executive Order 14 (as amended, July 16, 2018), the Regulations for Filing and Publishing Agency Regulations (1VAC7-10), and the *Form and Style Requirements for the Virginia Register of Regulations and Virginia Administrative Code.*

Brief Summary

Provide a brief summary (preferably no more than 2 or 3 paragraphs) of this regulatory change (i.e., new regulation, amendments to an existing regulation, or repeal of an existing regulation). Alert the reader to all substantive matters. If applicable, generally describe the existing regulation.

Chapter 1219 of the 2020 Acts of Assembly amends the Air Pollution Control Law to add a new Article 4, the Clean Energy and Community Flood Preparedness Act. Under § 10.1-1330 A, Clean Energy and Community Flood Preparedness, "[T]he provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et seq.)."

Accordingly, Part VII of 9VAC5-140, Regulation for Emissions Trading, has been amended such that it comports with the full Regional Greenhouse Gas Initiative (RGGI) CO_2 emissions trading program and associated auction as mandated by Chapter 1219.

Mandate and Impetus

Identify the mandate for this regulatory change and any other impetus that specifically prompted its initiation (e.g., new or modified mandate, internal staff review, petition for rulemaking, periodic review, or board decision). "Mandate" is defined as "a directive from the General Assembly, the federal government, or a court that requires that a regulation be promulgated, amended, or repealed in whole or part."

The mandate for this regulatory action is a directive from the General Assembly (Chapter 1219, 2020 Acts of Assembly).

Statement of Final Agency Action

Provide a statement of the final action taken by the agency including: 1) the date the action was taken; 2) the name of the agency taking the action; and 3) the title of the regulation.

On #[date], the Director of the Virginia Department of Environmental Quality (DEQ) incorporated the provisions of Chapter 1219 of the 2020 Acts of Assembly, without further action by the State Air Pollution Control Board, into the final regulation adopted by the board on April 19, 2019, and published in the Virginia Register on May 27, 2019, by amending the Regulation for Emissions Trading, specifically, the CO_2 Budget Trading Program (Part VII of 9VAC5-140). The regulatory action is to be effective on #[date].

The regulation amendments are exempt from the state administrative procedures for adoption of regulations contained in the Administrative Process Act by the provisions of Chapter 1219 of the 2020 Acts of Assembly

REG\DEV\A20-09TF

NOTE

The preceding Director's Package document references an Attachment 3 on page 2. That attachment is protected from disclosure by attorney-client privilege, and is therefore not included. The memorandum following this page from the Office of Attorney General is that publically available.

MEMORANDUM

FROM: Gray O'Dwyer
Assistant Attorney General

DATE: July 09, 2020

RE: Proposed Exempt Regulations - 9 Va. Admin. Code §§ 5-140 *et seq.*

Please note that this memorandum does not constitute an opinion, formal or informal, of the Attorney General. Rather, this memorandum contains the legal analysis of the individual staff member providing it.

It is my view that the Department of Environmental Quality ("Department") on behalf of the Virginia Air Pollution Control Board ("Board") has the authority to promulgate these proposed amendments to its regulations in 9 Va. Admin. Code §§ 5-140 *et seq.*

It is also my view that this regulation is exempted from the Virginia Administrative Process Act, §§ 2.2-4000 *et seq.*, by its enabling legislation. Chapter 1219 of the 2020 Acts of Assembly amended the Air Pollution Control Law to add a new Article 4, the Clean Energy and Community Flood Preparedness Act. Under § 10.1-1330 A, Clean Energy and Community Flood Preparedness, "[T]he provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et seq.)."

The foregoing conclusion is my own. It does not constitute an opinion, formal or informal, of the Attorney General.

COMMONWEALTH OF VIRGINIA

BEFORE THE STATE AIR POLLUTION CONTROL BOARD

IN RE: State Air Pollution Control Board
Final Regulation 9 VAC §§ 5-140 *et seq.*
Regulation for Emissions Trading Programs
Amending 9 VAC § 5-140-6010 through 9 VAC § 5-140-6440

NOTICE OF APPEAL

In accordance with Rule 2A:2 of the Rules of the Supreme Court of Virginia, the Virginia Manufacturers Association ("Appellant" or "VMA") hereby files this notice of appeal with David K. Paylor, Executive Secretary of the Virginia State Air Pollution Control Board, for judicial review of the Virginia Department of Environmental Quality's amendments of the Regulation for Emissions Trading Programs (9 VAC §§ 5-140 *et seq.*) as a final regulation, effective on July 10, 2020.

The appeal of this case decision will be taken to the Circuit Court for the City of Richmond, 13th Judicial Circuit of Virginia, located at 400 North Ninth Street, Richmond, Virginia 23219. Under Rule 2A:3 of the Rules of the Supreme Court of Virginia, the agency record should be forwarded to the Clerk of the Circuit Court for the City of Richmond as soon as possible.

As required by Rule 2A:2(b) of the Rules of the Supreme Court of Virginia, the Appellant provides the following information:

1. The Appellant is:

   Virginia Manufacturers Association
   2108 W. Laburnam Ave, Suite 230
   Richmond, VA 23227

2. Counsel for the Appellant is:

Elizabeth C. Williamson, Esq.
John M. Holloway, Esq.
Williams Mullen
200 South 10th Street
Richmond, VA 23219

3. The Appellee is:

Virginia State Air Pollution Control Board
Virginia Department of Environmental Quality
c/o David K. Paylor, Executive Secretary and Director
1111 East Main Street St., Suite 1400
Richmond, VA 23219

4. Counsel for the Appellee is:

Mark R. Herring, Attorney General of Virginia
Gray O'Dwyer, Assistant Attorney General
Office of the Attorney General of Virginia
202 North Ninth Street
Richmond, VA 23219

Dated: September 2, 2020

Respectfully submitted,

Virginia Manufacturers Association

Elizabeth C. Williamson, Esq.
John M. Holloway, Esq.

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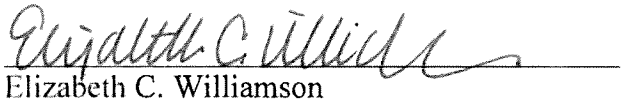
CERTIFICATE OF SERVICE

I hereby certify that on September 2, 2020, I have hand-delivered a complete copy of the foregoing Notice of Appeal to Appellee and its counsel identified above.



Elizabeth C. Williamson

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VIRGINIA:

IN THE CIRCUIT COURT OF THE CITY OF RICHMOND

Virginia Manufacturers Association,

Appellant,

v. Case No.: CL20004918-00

Virginia Department of Environmental Quality, et al.

Appellees.

CERTIFICATE OF SERVICE

I certify that on this 18th of March, 2021, I mailed by first class mail, postage prepaid, a true copy of the foregoing Agency Record to

Elizabeth C. Williamson, Esq.
John M. Holloway, III, Esq.
Harold E. Johnson, Esq.
Williams Mullen
200 South 10th Street
Suite 1600
Richmond, Virginia 23219
Counsel for Appellant

Michael G. Dowd, on behalf of Appellees,
Virginia Department of Environmental Quality, et al.

Attachment 13

The Washington Post
Democracy Dies in Darkness

Youngkin says he will take Virginia out of the Regional Greenhouse Gas Initiative to save ratepayers money

By Laura Vozzella

Updated December 8, 2021 at 8:08 p.m. EST | Published December 8, 2021 at 6:37 p.m. EST

CORRECTION

A previous version of this article incorrectly calculated the amount ratepayers would save yearly on electric bills if Virginia pulled out of a regional greenhouse gas compact. They would save $52.44 per year, not $227.24 per year. This article has been corrected.

RICHMOND — Gov.-elect Glenn Youngkin (R) told a business group Wednesday that he will use executive action to pull Virginia out of a regional greenhouse gas compact, a plan that Democrats said would cost the state hundreds of millions a year in flooding and energy-assistance funding.

The typical residential customer would save $4.37 a month on electric bills, or $52.44 per year, if Virginia pulled out, Youngkin's transition office said.

Nearly two years ago, as Democrats took control of the House of Delegates, Virginia joined the Regional Greenhouse Gas Initiative — a carbon cap-and-trade market among states in the Northeast and Mid-Atlantic. It was part of sweeping environmental legislation that also set a goal of going carbon-free by 2050.

In a speech to the Hampton Roads Chamber of Commerce, Youngkin said he will take the state out of the RGGI, as the regional initiative is known.

“RGGI describes itself as a regional market for carbon. It is really a carbon tax that is fully passed on to ratepayers,” he said. “It’s a bad deal for Virginians. It’s a bad deal for Virginia businesses. And as governor, I will withdraw us from RGGI by executive action. I promised to lower the cost of living in Virginia, and this is just the beginning.”

Del. Todd Gilbert (R-Shenandoah), who is slated to become House speaker when Republicans take back control of the chamber in January, cheered the news, saying RGGI’s impact on climate change has been “negligible at best.”

“Virginia was reducing carbon emissions from power plants at a rate comparable to RGGI states before joining the cap and trade group,” Gilbert said in a written statement. “When a policy costs the public a significant amount of money for no tangible benefit, that policy should be examined carefully, and if practical, rolled back.”

Some RGGI supporters said they were disappointed and questioned Youngkin’s authority to single-handedly pull the state out.

“I can assure you there’s a lot of lawyers … that are busy going to the books right now,” said Sen. Lynwood W. Lewis Jr. (D-Accomack), who sponsored the legislation in the Senate.

Regardless of Youngkin’s action on RGGI, the carbon targets will remain in state code — something that cannot be changed without new legislation from the General Assembly, said Cale Jaffe, an associate professor at the University of Virginia School of Law and director of the school’s Environmental Law and Community Engagement Clinic. The Senate remains under narrow Democratic control.

“You might leave this multistate trading program but still have to meet the zero-carbon mandate in the code,” Jaffe said. “Leaving the trading program just seems like cutting off your nose to spite your face. … I don’t know why you would relinquish a market that is helping to make the Clean Economy Act more affordable.”

Lewis said Virginia raised $227 million early this year in its first auction of carbon credits — money earmarked for flood preparedness across the state and energy-efficiency programs for low-income ratepayers.

“Regardless of your political party, if you’re a legislator in an area that’s impacted by sea-level rise of just recurrent flooding … you should be very reluctant and cautious in completely devastating that fund,” Lewis said. “This was going to provide a significant source of revenue.”

In his remarks to the chamber, Youngkin pledged to formulate a plan to “combat sea-level rise” before vowing to get the state out of RGGI via executive action. Asked about his authority to do so, Youngkin’s transition office issued a statement saying, “Virginia’s participation is governed by a contract agreement, signed by the Department of Environmental Quality and other regulations.”

Language in the statute directs the Department of Environmental Quality to manage the auction program under RGGI, Jaffe said, so that may be the avenue Youngkin is exploring, because the governor has the authority to direct the department’s actions. But under the legislation, the state’s Air Pollution Control Board has already promulgated regulations establishing a multistate trading program, he said.

“The governor cannot just undo regulations that he might not like via executive order,” Jaffe said, noting that it would be up to the seven-member board, currently all Democratic appointees, to change the regulations. Youngkin will not have the chance to put his own appointees on the board until July, when two seats will become open.

The members’ staggered four-year terms are “designed so you avoid this kind of whiplash,” Jaffe said.

Attachment 14

COMMONWEALTH of VIRGINIA

Office of the Attorney General

Mark R. Herring
Attorney General

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7-1-1

January 11, 2022

The Honorable Charniele L. Herring
Member, Virginia House of Delegates
Post Office Box 11779
Alexandria, Virginia 22312

The Honorable Richard "Rip" Sullivan
Member, Virginia House of Delegates
Post Office Box 50753
Arlington, Virginia 22205

Dear Delegates Herring and Sullivan:

I am responding to your request for an official advisory opinion in accordance with § 2.2-505 of the Code of Virginia.

Issue Presented

You ask whether the Governor, solely through an executive order or other executive action, can repeal or eliminate the regulatory requirement that electric utilities and other electricity producers hold carbon dioxide allowances that equal the amount of their carbon dioxide emissions.

Discussion and Analysis

The Clean Energy and Community Flood Preparedness Act (the "Act") was passed by the General Assembly in 2020, amended Va. Code § 10.1-1330. The Act directs the Virginia Department of Environmental Quality to amend its regulations that established a carbon dioxide cap and trade program to reduce carbon dioxide emissions. Section 10.1-1330(B) authorizes the Director of DEQ "to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the [Regional Greenhouse Gas Initiative] program and this article."[1]

Consistent with the Act's requirements, DEQ issued amendments to its CO_2 Budget Trading Program regulations. Pursuant to those regulations, an owner or operator of a CO_2 budget source, such as an electric utility, must "hold CO2 allowances . . . in an amount not less than CO2 emissions that have been

[1] VA. CODE ANN. § 10.1-1300(B). This and other citations to the Code of Virginia herein are from the electronic version of the Code on LexisNexis and are current through the 2021 Regular Session and Special Session I and II of the General Assembly.

generated as a result of combusting fossil fuel" for a given time period.[2] Put differently, in order to lawfully produce electricity in Virginia by combusting fossil fuels, producers must now hold carbon dioxide allowances that equal the amount of their carbon dioxide emissions. One of the ways producers obtain CO_2 allowances in order to comply with this regulation is by purchasing them through the Regional Greenhouse Gas Initiative auction. You have asked whether the Governor may, through an executive order or other executive action, do away with this regulatory requirement.

A recent Attorney General opinion discussed the separation of powers doctrine with respect to the Governor's power to alter tax laws.[3] The same rationale applies to validly enacted laws. The Constitution of Virginia does not grant the Governor the power to suspend laws, and in fact, it requires the opposite that "[t]he Governor shall take care that the laws be faithfully executed."[4] Article I, § 7 of the Constitution of Virginia provides "[t]hat all power of suspending laws, or the execution of laws, by any authority, without consent of the representatives of the people, is injurious to their rights, and ought not to be exercised."

A previous Attorney General opinion explained the interplay between these sections of the Constitution. "Thus, the prohibition that is implicit in Article V, § 7's 'take care' clause is made explicit by Article I, § 7: the Governor may not unilaterally direct, by any means, that a validly adopted regulation that has the force of law be suspended or ignored."[5] In my opinion, the Governor may not repeal or eliminate, through an executive order or other action, the enacted statutes and regulations pertaining to the Commonwealth's participation in the Regional Greenhouse Gas Initiative and/or a market-based trading program like the Regional Greenhouse Gas Initiative, or do away with the requirement that electricity producers hold carbon dioxide allowances that equal the amount of their carbon dioxide emissions.

Conclusion

Accordingly, it is my opinion that the Governor may not, solely through an executive order or other executive action, repeal or eliminate the regulatory requirement that electric utilities and other electricity producers hold carbon dioxide allowances that equal the amount of their carbon dioxide emissions.

With kindest regards, I am,

Very truly yours,

Mark R. Herring

Mark R. Herring
Attorney General

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[2] 9 VA. ADMIN. CODE § 5-140-6050(C) (2021).

[3] 2021 Op. Va. Att'y Gen. No. 21-087, available at https://www.oag.state.va.us/citizen-resources/opinions/official-opinions/30-resource/opinions/1917-2021-official-opinions#november.

[4] VA. CONST., art. V § 7.

[5] 2014 Op. Va. Att'y Gen. 43, 45-46.

Attachment 15

Commonwealth of Virginia
Office of the Governor

Executive Order

NUMBER NINE (2022)

PROTECTING RATEPAYERS FROM THE RISING COST OF LIVING DUE TO THE REGIONAL GREENHOUSE GAS INITIATIVE

By virtue of the authority vested in me as Governor, I hereby issue this Executive Order to re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative and immediately begin regulatory processes to end it.

Importance of the Initiative

Reliable and affordable access to electricity is imperative to the health and safety of all Virginians. Our hospitals, schools, businesses, and homes all rely on this essential service. And the unpredictable and rising cost of electricity poses a significant and immediate threat to our Commonwealth and its citizens. In 2019, alone, over 100,000 Virginian households required Energy Assistance with a cost of $46 million to the Commonwealth.

Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) risks contributing to the increased cost of electricity for our citizens. Virginia's utilities have sold over $227 million in allowances in 2021 during the RGGI auctions, doubling the initial estimates. Those utilities are allowed to pass on the costs of purchasing allowances to their ratepayers. Under the initial bill "RGGI rider" created for Dominion Energy customers, typical residential customer bills were increased by $2.39 a month and the typical industrial customer bill by was raised by $1,554 per month. In a filling before the State Corporation Commission, Dominion Energy stated that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.

Simply stated, the benefits of RGGI have not materialized, while the costs have skyrocketed. Re-evaluation of the Initiative represents a meaningful step toward alleviating this financial burden on the Commonwealth's businesses and households. Regulations must be evaluated in view of the costs and benefits to all Virginians.

Directive

Accordingly, by virtue of the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural and Historic Resources, to take the following actions in accordance with the provisions and requirements of § 10.1-1300, et seq. and § 2.2-4000, et seq. of the *Code of Virginia*:

1. Provide me a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data, within 30 days.

2. During this same period, develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal 9VAC5-140.

3. During this same period, take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the *Code of Virginia*.

4. During this same period, notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

Effective Date

This Executive Order shall be effective upon its signing and shall remain in force and effect unless amended or rescinded by further executive order or directive.

Given under my hand and under the Seal of the Commonwealth of Virginia, this 15th day of January 2022.

Glenn Youngkin, Governor

Attest:

Kelly Thomasson, Secretary of the Commonwealth

Attachment 16

ENERGY + ENVIRONMENT

Youngkin administration outlines plan to withdraw Virginia from carbon market by regulation

Opponents insist legislation is required for RGGI withdrawal

By: Charlie Paullin - September 1, 2022 12:04 am

Environmental activists rally outside of Community College Workforce Alliance in Richmond before a Air Pollution Control Board meeting in which Secretary of Natural and Historic Resources Travis Voyles announced the plan to withdrawal Virginia from the Regional Greenhouse Gas Initiative, or RGGI. RGGI aims to reduce energy producer carbon emissions. The activists want to stay in it. (Charlie Paullin/The Mercury).

Gov. Glenn Youngkin's administration announced their newest plans for how they intend to withdraw Virginia from a regional carbon market Wednesday, a move critics say is not allowed by law, would drain important state programs of funding and would hurt the fight against climate change.

Acting Secretary of Natural and Historic Resources Travis Voyles said at a State Air Pollution Control Board meeting that the administration plans to withdraw Virginia from the Regional Greenhouse Gas Initiative through changes to the regulations that govern the state's participation in the market.

The regulatory process typically takes 18 to 24 months from start to finish, after which the air board will vote on repealing the regulation.

The move is a pivot from the approach outlined in an executive order Youngkin issued at the start of his term. That plan called for a two-track approach that would first repeal the regulation through an emergency provision and then eliminate it permanently through the normal regulatory process.

The full regulatory process "will allow for public comment … provides some certainty and times well with the contractual period," Voyles told the Virginia Mercury after the meeting.

Virginia's three-year contract with RGGI, Inc., the body that coordinates the market, ends next year.

RGGI is a carbon reduction market involving 10 other Mid-Atlantic and New England states in which energy producers must buy allowances for the carbon they emit, and a cap is placed on overall carbon emissions.

The proceeds of purchasing those allowances are then returned to the state. In Virginia, they're funneled into flood assistance and low-income energy efficiency programs. Virginia has received some $379 million in RGGI proceeds to date.

Under state law, electric utilities are permitted to pass on the costs of RGGI participation to ratepayers. The Youngkin administration has said those increased costs, which averaged $2.39 per month for Dominion residential customers, are a burden on ratepayers. Dominion has since stopped charging customers a specific fee for RGGI participation.

"RGGI is a bad deal for Virginia," Voyles said, adding that the state can't control the market costs for allowances, which have increased.

But groups like the Southern Environmental Law Center continue to say the Youngkin administration can't withdraw Virginia from RGGI by changing regulations because the regulations were the result of legislation passed by the General Assembly in 2020.

"That's not consistent with the law," SELC attorney Nate Benforado said.

From 2010 to 2020, before Virginia joined RGGI, power plant emissions did not decrease, Benforado stated, referencing a March report on the program that the Department of Environmental Quality completed at Youngkin's request. Emissions dropped over 30% with RGGI participation, he added.

"Virginia needs RGGI," Benforado said.

Board response

Reactions from the seven-member board differed among the four appointees made by Youngkin, a Republican, and the three appointees made by former Gov. Ralph Northam, a Democrat.

Northam appointee Hope Cupit, president and CEO of SERCAP, an organization that helps low- to moderate-income people in the southeastern U.S, asked whether it was constitutional to override the RGGI law passed by the General Assembly through regulations.

Cupit has previously said she received an email from an attorney with the Office of the Attorney General saying the air board doesn't have the authority to withdraw Virginia from RGGI. A lawsuit seeking to force the release of that email under the state's Freedom of Information Act is still awaiting an order from a judge in Charlottesville Circuit Court.

She also noted the benefits of flood protection programs funded by RGGI given recent flooding in Buchanan County.

"We feel forgotten sometimes," said Cupit, who lives in Bedford.

Another Northam appointee, retired pulmonologist Lornel Tompkins, said one year's worth of data on Virginia's participation in RGGI is not enough to determine its effectiveness. She also questioned why the RGGI fee was being attacked, versus other fees utility customers pay, and said costs could be lower in the long run.

"Why are we not going after the General Assembly to change the rules, rather than taking away something from the state or the commonwealth which is turning out by some factors to be a positive?" Tompkins said.

Conversely, Youngkin appointee David Hudgins, executive director for the Virginia Energy Consumer Trust, an advocacy group skeptical of renewables, said he was concerned about RGGI's impact on the state's ability to appeal to business because of rising energy costs. Virginia has previously been able to attract businesses from the Northeast by touting its lower electricity rates, he said.

"If we get affiliated (with) the Northeast, southern states are going to start sending their economic development teams up here because our cost structure is changing and reflecting more of the Northeast than we do with the people to the south," Hudgins said.

Another Youngkin appointee, retired attorney Jay Holloway, asked whether RGGI actually caps carbon emissions because it allows producers to buy allowances beyond the cap.

But Michael Dowd, director of DEQ's Air and Renewable Energy Division, clarified that allowances can only exceed the cap by a certain percentage.

"There is a cap, in a general sense, because it is a regional cap. There is a finite number of allowances for sale," Dowd said.

Environmental outcry

Several environmental groups rallied outside the meeting's location at the Community College Workforce Alliance in Richmond, with rallies also held throughout the state in Roanoke, Harrisonburg, Woodbridge, Abingdon and Virginia Beach.

In Richmond, activists displayed caricatures of Youngkin and former Environmental Protection Agency chief Andrew Wheeler while chanting "RGGI is the law."

Wheeler, who is serving as an adviser to Youngkin, was appointed to his current position after Senate Democrats stymied his nomination to be secretary of natural and historic resources. The Democrats' move led to Republicans blocking 11 other Northam-era appointments, including two air board members.

Leah Jones, a coordinator with Virginia Interfaith Power & Light, a group focused on climate and environmental justice, called RGGI "an important stepping stone for our state to provide funds to those affected by energy burden and severe flooding while also providing an incentive … to act on climate and reduce Virginia's carbon emissions."

Jones and five other public speakers spoke in support of RGGI during Wednesday's meeting. Virginia Manufacturers Association executive director Brett Vassey spoke against it, calling RGGI a tax and accusing it of being redundant given Virginia's emission reduction efforts through the Virginia Clean Economy Act.

While the Virginia Clean Economy Act sets aggressive carbon reduction goals for the state's regulated utilities, it does not apply to non-utility power producers, who generate more than a quarter of the state's carbon emissions subject to RGGI.

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Attachment 17

townhall.virginia.gov

Proposed Regulation
Agency Background Document

Agency name	State Air Pollution Control Board
Virginia Administrative Code (VAC) Chapter citation(s)	Part VII of 9VAC5-140
VAC Chapter title(s)	Regulation for Emissions Trading
Action title	Repeal CO_2 Budget Trading Program as required by Executive Order 9 (Revision A22)
Date this document prepared	December 7, 2022

This information is required for executive branch review and the Virginia Registrar of Regulations, pursuant to the Virginia Administrative Process Act (APA), Executive Order 19 (2022) (EO 19), any instructions or procedures issued by the Office of Regulatory Management (ORM) or the Department of Planning and Budget (DPB) pursuant to EO 19, the Regulations for Filing and Publishing Agency Regulations (1 VAC 7-10), and the *Form and Style Requirements for the Virginia Register of Regulations and Virginia Administrative Code*.

Brief Summary

Provide a brief summary (preferably no more than 2 or 3 paragraphs) of this regulatory change (i.e., new regulation, amendments to an existing regulation, or repeal of an existing regulation). Alert the reader to all substantive matters. If applicable, generally describe the existing regulation.

Executive Order 9 (2022), "Protecting Ratepayers from the Rising Cost of Living Due to the Regional Greenhouse Gas Initiative," requires that the department re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) and begin regulatory processes to end it. Specifically, the order requires that the department develop a regulation for the State Air Pollution Control Board's consideration to repeal the implementing regulation implementing participation in RGGI (Part VII of 9VAC5-140), and take all necessary steps so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the Code of Virginia. This regulatory action repeals Part VII of 9VAC-140, and adds transition language in a new section in order that the repeal be implemented without disruption to affected facilities or the market.

Acronyms and Definitions

Define all acronyms used in this form, and any technical terms that are not also defined in the "Definitions" section of the regulation.

APA - Virginia Administrative Process Act
ASNH - Affordable and Special Needs Housing
CFPF - Community Flood Preparedness Fund
CO_2 - carbon dioxide
DCR - Virginia Department of Conservation and Recreation
DEQ - Virginia Department of Environmental Quality
DHCD - Virginia Department of Housing and Community Development
DOE - Virginia Department of Energy
GHG - greenhouse gas
HIEE - Housing Innovations in Energy Efficiency
EO-9 - Executive Order 9 (2022)
kWh - kilowatt hour
MWe - megawatt electrical
NO_X - nitrogen oxides
PDC - planning district commission
PJM - PJM Interconnection
REC - renewable energy certificate
RGGI - Regional Greenhouse Gas Initiative
RPS - Renewable Energy Portfolio Standards
SCC - State Corporation Commission
SO_2 - sulfur dioxide
U.S. DOE - U.S. Department of Energy
VCEA - Virginia Clean Economy Act
WAP - Weatherization Assistance Program
WDR - Weatherization Deferral Repair

Mandate and Impetus

Identify the mandate for this regulatory change and any other impetus that specifically prompted its initiation (e.g., new or modified mandate, petition for rulemaking, periodic review, or board decision). For purposes of executive branch review, "mandate" has the same meaning as defined in the ORM procedures, "a directive from the General Assembly, the federal government, or a court that requires that a regulation be promulgated, amended, or repealed in whole or part."

The mandate and necessity for this regulatory change are described in EO-9 as follows:

> Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) risks contributing to the increased cost of electricity for our citizens. Virginia's utilities have sold over $227 million in allowances in 2021 during the RGGI auctions, doubling the initial estimates. Those utilities are allowed to pass on the costs of purchasing allowances to their ratepayers. Under the initial bill "RGGI rider" created for Dominion Energy customers, typical residential customer bills were increased by $2.39 a month and the typical industrial customer bill by was raised by $1,554 per month. In a filling before the State Corporation Commission, Dominion Energy stated that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.
>
> Simply stated, the benefits of RGGI have not materialized, while the costs have skyrocketed. Re-evaluation of the Initiative represents a meaningful step toward alleviating this financial burden on the

Commonwealth's businesses and households. Regulations must be evaluated in view of the costs and benefits to all Virginians.

According to the U.S. DOE, Virginians pay on average $2,323 per year in non-transportation energy costs, which is higher than the national average of $1,850. The index for electricity rose by more than 13% over the last 12 months, the largest single-year increase since 2006, while the natural gas index rose by 38.4%--the biggest 12-month jump since October 2005. In July 2022 alone, electricity prices rose 1.7% and natural gas prices 8.2%. Considering that Virginia obtains most of its electricity from natural gas, rising natural gas prices have forced electricity prices even higher.

Dominion Energy has filed for 16 rate adjustments over a 12-month period ending July 1, 2022. In May 2022 alone, Dominion filed for a rate increase with the State Corporation Commission (SCC) that could result in monthly rate increases between 12-20% due to rising fuel costs. The cumulative impact of those adjustments results in an increase of $0.022423/kilowatt hour or 18% in Dominion's rates that it charges for delivered electricity. This assumes final SCC approval of the fuel rate adjustment and its agreement to Dominion's request to amortize the fuel adjustment over three years.

According to the most recent data supplied by the Federal Energy Information Administration (2020), the average annual household consumption of electricity in Virginia is 13,140 kilowatt hours. Historically, the average energy consumption in Virginia has increased by 1.38% per year. The cumulative impact of the adjustments described above would increase the average household's bill by approximately $294 per year, but will increase as consumption continues to increase.

The current energy framework in Virginia allows energy providers to also charge ratepayers for the transition and expansion of clean energy infrastructure. For example, the SCC recently approved an application by Dominion for cost recovery associated with its proposed Coastal Virginia Offshore Wind Project. The project consists of 176 wind turbines, each designed to generate 14.7 megawatts, to be located about 27 miles off the coast of Virginia Beach. The project is expected to have a capital cost of $9.8 billion and will likely be the largest capital investment, and single largest project, in Dominion's history. The SCC approved a revenue requirement of $78.702 million for the rate year of September 1, 2022, to August 31, 2023, to be recovered through a new rate adjustment clause. Over the projected 35-year lifetime of the project, for a residential customer using 1,000 kilowatt-hours of electricity per month, the rate adjustment is projected to result in an average monthly bill increase of $4.72 and a peak monthly bill increase of $14.22 in 2027. This is another instance of upward pressure on utility costs with a direct impact on consumers.

These energy cost increases are coming at a time that Virginians can least afford them. As of June 2022, inflation has risen 9.1% on an annual basis, the highest increase in over 40 years. According to the Bureau of Labor Statistics, consumer energy prices are up 41.6% in the last year. The rate of inflation for energy is more than four times the inflation rate of all food items and the Consumer Price Index.

Real wage growth has not kept pace with this rapid inflation, and real wages decreased by 1% in June 2022; over the last year they have decreased 3.6%. This hurts Virginia families, and those families and individuals who can least afford increases in energy costs. According to the American Council for an Energy Efficient Economy, "Black households spend 43% more of their income on energy costs, Hispanic households spend 20% more, and Native American households spend 45% more. Low-income households (those with incomes 200% of the federal poverty level) spend three times more of their income on energy costs than non-low income households."

EO-9 directed the department to provide the Governor with a full report re-evaluating the costs and benefits of participation in RGGI in view of all available data. As detailed above, it is clear that in effect participation in RGGI operates as a direct tax on households and businesses. Since the consumers are utility-captive ratepayers that do not have the opportunity to switch electric providers, they are unable to avoid the pass-through of RGGI costs—whether through a direct rate adjustment clause or incorporation into the base rate of their electricity bill. Emission allowance prices have increased over 146% since Virginia joined RGGI in 2020, and these substantial increases are expected to continue, which in turn will result in increased rates to ratepayers.

The original analysis and consignment auction approach for RGGI was designed on the basis that proceeds would be returned to offset the cost of compliance, and have little impact on electricity prices. However, since this is not how the program was implemented in Virginia, the costs of compliance with RGGI have materialized in higher electricity rates for Virginians. The impact of RGGI and the other factors discussed above on the current state of electricity costs shows a substantial burden placed on Virginians that must be addressed.

Legal Basis

Identify (1) the promulgating agency, and (2) the state and/or federal legal authority for the regulatory change, including the most relevant citations to the Code of Virginia and Acts of Assembly chapter number(s), if applicable. Your citation must include a specific provision, if any, authorizing the promulgating agency to regulate this specific subject or program, as well as a reference to the agency's overall regulatory authority.

Statutory Authority

Section 10.1-1308 of the Virginia Air Pollution Control Law (Title 10.1, Chapter 13 of the Code of Virginia) authorizes the State Air Pollution Control Board to promulgate regulations abating, controlling and prohibiting air pollution in order to protect public health and welfare.

Promulgating Entity

The promulgating entity for this regulation is the State Air Pollution Control Board.

State Requirements

EO-9 specifically directs the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural and Historic Resources, to present to the State Air Pollution Control Board a regulation amendment to repeal 9VAC5-140 in accordance with the board's authority pursuant to § 10.1-1308 of the Code of Virginia.

Purpose

Explain the need for the regulatory change, including a description of: (1) the rationale or justification, (2) the specific reasons the regulatory change is essential to protect the health, safety or welfare of citizens, and (3) the goals of the regulatory change and the problems it is intended to solve.

As described in the Mandate and Impetus section of this document, EO-9 describes the necessity for this regulatory change in order to protect public health, safety, and welfare.

Substance

Briefly identify and explain the new substantive provisions, the substantive changes to existing sections, or both. A more detailed discussion is provided in the "Detail of Changes" section below.

The purpose of this regulatory action is to repeal Part VII of 9VAC5-140 in its entirety, while adding a new transition section so that the repeal will be effected smoothly.

Issues

Identify the issues associated with the regulatory change, including: 1) the primary advantages and disadvantages to the public, such as individual private citizens or businesses, of implementing the new or amended provisions; 2) the primary advantages and disadvantages to the agency or the Commonwealth; and 3) other pertinent matters of interest to the regulated community, government officials, and the public. If there are no disadvantages to the public or the Commonwealth, include a specific statement to that effect.

The primary advantage to the public include reduced residential and commercial energy costs.

The primary advantages to the Commonwealth are reduced energy costs. The Commonwealth will also benefit from greater certainty and transparency in the energy markets.

There are no disadvantages to the public or the Commonwealth associated with this regulatory change.

Requirements More Restrictive than Federal

Identify and describe any requirement of the regulatory change which is more restrictive than applicable federal requirements. Include a specific citation for each applicable federal requirement, and a rationale for the need for the more restrictive requirements. If there are no applicable federal requirements, or no requirements that exceed applicable federal requirements, include a specific statement to that effect.

There are no applicable federal requirements.

Agencies, Localities, and Other Entities Particularly Affected

Consistent with § 2.2-4007.04 of the Code of Virginia, identify any other state agencies, localities, or other entities particularly affected by the regulatory change. Other entities could include local partners such as tribal governments, school boards, community services boards, and similar regional organizations. "Particularly affected" are those that are likely to bear any identified disproportionate material impact which would not be experienced by other agencies, localities, or entities. "Locality" can refer to either local governments or the locations in the Commonwealth where the activities relevant to the regulation or regulatory change are most likely to occur. If no agency, locality, or entity is particularly affected, include a specific statement to that effect.

Other State Agencies Particularly Affected

Department of Housing and Community Development (DHCD); Department of Conservation and Recreation (DCR) Flood Preparedness Fund.

Localities Particularly Affected

No locality will be particularly affected by this action.

Other Entities Particularly Affected

Organizations that receive funding from DHCD and DCR; any fossil fuel-fired unit that serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe (megawatt electrical).

Economic Impact

Consistent with § 2.2-4007.04 of the Code of Virginia, identify all specific economic impacts (costs and/or benefits) anticipated to result from the regulatory change. When describing a particular economic impact, specify which new requirement or change in requirement creates the anticipated economic impact. Keep in mind that this is the proposed change versus the status quo.

Impact on State Agencies

For your agency: projected costs, savings, fees, or revenues resulting from the regulatory change, including: a) fund source / fund detail; b) delineation of one-time versus on-going expenditures; and c) whether any costs or revenue loss can be absorbed within existing resources.	It is expected that repealing the regulation will not result in any cost to the department. The sources of department funds to carry out this regulation are currently the general fund and RGGI funds (3% of total auction proceeds for administrative needs), which will no longer be generated. The activities are budgeted under the following programs (codes): Air Protection Permitting (513025); Air Protection Compliance and Enforcement (513026); Air Protection Planning and Policy (513028); and Air Protection Monitoring and Assessment (513029). The ongoing costs will cease with the program.
For other state agencies: projected costs, savings, fees, or revenues resulting from the regulatory change, including a delineation of one-time versus on-going expenditures.	DHCD: Any ongoing expenses associated with administering the program will cease with the program. DCR: Any ongoing expenses associated with administering the program will cease with the program.
For all agencies: Benefits the regulatory change is designed to produce.	The primary benefits of the regulatory change are reduced energy costs, and greater certainty and transparency in the energy markets.

Impact on Localities

If this analysis has been reported on the ORM Economic Impact form, indicate the tables (1a or 2) on which it was reported. Information provided on that form need not be repeated here.

Projected costs, savings, fees, or revenues resulting from the regulatory change.	See ORM Economic Impact form.
Benefits the regulatory change is designed to produce.	See ORM Economic Impact form.

Impact on Other Entities

If this analysis has been reported on the ORM Economic Impact form, indicate the tables (1a, 3, or 4) on which it was reported. Information provided on that form need not be repeated here.

Description of the individuals, businesses, or other entities likely to be affected by the regulatory change. If no other entities will be affected, include a specific statement to that effect.	See ORM Economic Impact form.

Agency's best estimate of the number of such entities that will be affected. Include an estimate of the number of small businesses affected. Small business means a business entity, including its affiliates, that: a) is independently owned and operated, and; b) employs fewer than 500 full-time employees or has gross annual sales of less than $6 million.	See ORM Economic Impact form.
All projected costs for affected individuals, businesses, or other entities resulting from the regulatory change. Be specific and include all costs including, but not limited to: a) projected reporting, recordkeeping, and other administrative costs required for compliance by small businesses; b) specify any costs related to the development of real estate for commercial or residential purposes that are a consequence of the regulatory change; c) fees; d) purchases of equipment or services; and e) time required to comply with the requirements.	See ORM Economic Impact form.
Benefits the regulatory change is designed to produce.	See ORM Economic Impact form.

Alternatives to Regulation

Describe any viable alternatives to the regulatory change that were considered, and the rationale used by the agency to select the least burdensome or intrusive alternative that meets the essential purpose of the regulatory change. Also, include discussion of less intrusive or less costly alternatives for small businesses, as defined in § 2.2-4007.1 of the Code of Virginia, of achieving the purpose of the regulatory change.

1. Repeal the regulation to satisfy the provisions of EO-9. This option is being selected because it meets the stated purpose of the regulatory action.

2. Make alternative regulatory changes to those required by EO-9. This option is not being selected because it would not meet the stated purpose of the regulatory action.

3. Take no action. This option is not being selected because it would not satisfy the provisions of EO-9.

Regulatory Flexibility Analysis

Consistent with § 2.2-4007.1 B of the Code of Virginia, describe the agency's analysis of alternative regulatory methods, consistent with health, safety, environmental, and economic welfare, that will accomplish the objectives of applicable law while minimizing the adverse impact on small business. Alternative regulatory methods include, at a minimum: 1) establishing less stringent compliance or reporting requirements; 2) establishing less stringent schedules or deadlines for compliance or reporting requirements; 3) consolidation or simplification of compliance or reporting requirements; 4) establishing performance standards for small businesses to replace design or operational standards required in the proposed regulation; and 5) the exemption of small businesses from all or any part of the requirements contained in the regulatory change.

See ORM Economic Impact form.

Periodic Review and Small Business Impact Review Report of Findings

If you are using this form to report the result of a periodic review/small business impact review that is being conducted as part of this regulatory action, and was announced during the NOIRA stage, indicate whether the regulatory change meets the criteria set out in EO 19 and the ORM procedures, e.g., is necessary for the protection of public health, safety, and welfare; minimizes the economic impact on small businesses consistent with the stated objectives of applicable law; and is clearly written and easily understandable. In addition, as required by § 2.2-4007.1 E and F of the Code of Virginia, discuss the agency's consideration of: (1) the continued need for the regulation; (2) the nature of complaints or comments received concerning the regulation; (3) the complexity of the regulation; (4) the extent to the which the regulation overlaps, duplicates, or conflicts with federal or state law or regulation; and (5) the length of time since the regulation has been evaluated or the degree to which technology, economic conditions, or other factors have changed in the area affected by the regulation. Also, discuss why the agency's decision, consistent with applicable law, will minimize the economic impact of regulations on small businesses.

This form is not being used to report the result of a periodic review/small business impact review.

Public Comment

Summarize all comments received during the public comment period following the publication of the previous stage, and provide the agency's response. Include all comments submitted: including those received on Town Hall, in a public hearing, or submitted directly to the agency. If no comment was received, enter a specific statement to that effect.

Commenter	Comment	Agency response
1. About 50 Town Hall commenters	General support for the proposal. Key topics included the effectiveness of the program, and whether the program constitutes a tax and unneeded financial burden.	Support for the proposal is appreciated.
2. About 745 Town Hall commenters, and about 16 individual emails	General opposition to the proposal. Key topics included the legality of the regulatory action, the need for utility structure reform, protection of public health and welfare, and the need to fund resiliency and energy efficiency programs.	The commenters' concerns are acknowledged; detailed responses to specific issues are noted below.
3. About 225 identical emails sponsored by Virginia League of Conservation Voters	In a time of extreme weather and climate impacts, and rising energy costs, RGGI is bringing hundreds of millions of dollars to our state every year to help localities address flooding and sea level rise; and fund energy efficiency improvements for low-income households. An estimated 60% of total proceeds help either low-	The commenters' concerns are acknowledged; detailed responses to specific issues are noted below.

	income individuals directly, or low-income communities. Since January 2021, RGGI has generated upward of $378M for these efforts. With no Plan B to make up this revenue, this action would leave localities without funding to adapt to climate change and protect their communities, while also leaving low-income Virginians behind. Taking Virginia out of RGGI undermines our ability to cut harmful pollution from power plants; dirty air threatens us all, and RGGI is helping drive down pollution. This misguided repeal also imperils our economy. We are one of the fastest growing states for clean energy jobs because of strong policies like membership in RGGI, and we must stay the course to advance the clean energy transition. Lastly, Governor Youngkin lacks the authority to leave RGGI through the regulatory process--our participation is mandated by the General Assembly and only the General Assembly can legally take us out.	
4. Ceres	To reaffirm the sentiments of leading businesses in Virginia, we recognize that climate change poses a material risk to business operations, the livelihood of employees, and the health of Virginia's communities. In March 2020, a coalition of our Virginia based member companies and other large Virginia employers sent a letter in support of Virginia joining RGGI. In January 2022, 11 companies and educational institutions wrote a letter in support of maintaining and building upon Virginia's climate legislation. RGGI is one of many important tools that exist in Virginia to help businesses cut energy costs, avoid the volatility of fuel prices, and stay competitive. Our companies are motivated to make investments in places where we can continue to access these types of policies. We hope Virginia will continue to provide a hospitable environment for spurring clean energy adoption and expansion by	DEQ agrees with the commenters that that climate change represents a serious threat to Virginia's public health and welfare. We note that emissions of CO_2 and other pollutants have been and continue to decrease within Virginia's borders. Such decreases are not directly attributable to participation in RGGI but are primarily the result of other ongoing programs, thus, the health benefits resulting from reduced pollution are not attributable to RGGI participation. These programs include market-driven trends toward cleaner electricity generation (fuel switching, use of solar, etc.) and federal emissions reduction mandates (such as the suite of clean power rules and motor vehicle standards).

	not leaving RGGI. We appreciate the many economic opportunities presented by Virginia's continued transition to a clean energy economy. It is critical that these programs persist to ensure both the state and our companies achieve the shared goals of driving new in-state investment, encouraging innovation, and fostering long-term economic health.	
5. Ceres	RGGI is a cooperative agreement among 11 states; there is no abandonment or relinquishment of state sovereignty or responsibility. RGGI is implemented through a CO_2 Budget Trading Program specific to each member state. Virginia's DEQ coordinates Virginia's participation. Due to the structure of RGGI, member states are allowed to bank emission allowances for future use, which yields substantial flexibility in the trading program.	Participating RGGI states must follow a model rule which is agreed to by all states. Very little flexibility may be realized by states in changes to the model rule, and rightly so--such a regional agreement could not function effectively if there were significant differences among the participants. The fact remains that once a state enters into RGGI, that state must follow in step with every other state with respect to CO_2 budgets, compliance mechanisms, and the overall structure of RGGI. As previously noted, there are additional costs and steps associated with participating in RGGI that are avoided through direct implementation of Virginia programs by Virginia agencies.
6. Ceres	After decades of overinvestment in fossil fuels, Virginia's electric rates have climbed higher than every neighboring regulated state. Under the leadership of both Republicans and Democrats, RGGI states have seen their economies grow faster while utility rates are lower. RGGI states have agreed that at least 25% of the emission allowance value will be distributed for consumer benefit, which is predominantly used for energy efficiency and renewable energy investments. Studies have indicated that this provides multiple benefits of emission reductions, lower electricity bills, and regional job creation. Any adjustment in the utility rate structure should come through legislative reform and not the proven and successful RGGI program.	Virginia is currently a participating RGGI state, and has yet to see the lower utility rates. Over the past 15 years, an average monthly residential bill for a Dominion customer has increased by over $30 (roughly 34%). Consumer energy prices were up by 41.6% in the last year, with an increase in June 2022 alone of 9%. Natural gas is the predominant fuel in Virginia, and the natural gas price index is sharply higher (+38%), resulting in rate increases amounting to 18%. Furthermore, the cost of allowances continues to increase; these costs are being passed down directly to Virginia consumers. Given the current climate of economic distress, including increasing energy costs to every household and business in Virginia, the benefits of certain carbon control programs must be weighed against their costs, and their effectiveness carefully reviewed. It is important to note that all RGGI costs are passed through to the ratepayers as required by state law. By design, utilities are not penalized for failure to meet RGGI CO_2 emissions limits since they can pass on the costs to the ratepayers. Consumers are unable to avoid these costs because they do

		not have the opportunity to switch electric providers. Other states designed their systems to provide rebates to ratepayers, while the Virginia General Assembly chose to disburse the funds through grant programs. The costs of compliance with the trading rule and participation in RGGI are materializing in higher electricity rates for all ratepayers, and future rate increases due to RGGI are expected and will be tied to the allowance prices which are difficult to predict. We agree that any adjustments to the utility rate structure would require changes to state law that are beyond the purview of this regulatory action or the legal authority of DEQ to implement; however, the fact remains that participation in RGGI is not helping bring utility rates down in Virginia. Moreover, RGGI participation does not comport with the "all of the above" strategy espoused by the Commonwealth's 2022 Energy Plan.
7. Ceres	The market-based mechanisms of RGGI not only ensure that Virginia pursues the most economically efficient carbon reduction pathways, but that the proceeds from RGGI allow for the establishment of energy efficiency programs and the creation and expansion of flood mitigation programs in every corner of the state. Virginia has received approximately $452M in cumulative proceeds since its first auction in March 2021. In terms of health benefits, for the first six years of the RGGI program, RGGI states' improvement in air quality had a cumulative economic value of $5.7B. RGGI accounts for nearly half of the northeastern U.S. post-2009 emissions reductions, which is far greater than those achieved in the rest of the U.S. The estimated avoided cases of adverse children health outcomes from 2009-2020, includes an avoided cost ranging from $191-$350M. This monetary figure represents the prevention of infant mortality, preterm births, respiratory illness, and asthma among our most vulnerable Virginians.	Energy efficiency programs and resiliency measures are indeed needed throughout the state. These programs are obviously costly, and the money to fund them must be obtained one way or another; regardless, such programs should be funded in an open and transparent way, not through a third party. Other sources of funding are available, both state and federal, without the additional costs and complex means of creating and distributing the revenue that the RGGI program imposes. The Virginia General Assembly will also fund important resiliency and energy efficiency programs in future sessions.

8. Virginia Energy Efficiency Council (VEEC); City of Charlottesville; Virginia Conservation Network	RGGI provides unprecedented and irreplaceable funding for energy efficiency improvements in low income residences. Virginia is the only RGGI state that dedicates 50% of its carbon-trading funds to make both new and existing low-income housing more energy efficient, allowing weatherization providers and affordable housing developers to provide safe, affordable and energy-efficient homes to low-income families like never before. Only the General Assembly has the authority to cut off this vital funding source. Virginia's first year in RGGI provided nearly $114M in revenue for low-income energy efficiency housing. Administered by DHCD, the HIEE fund provides capital to make energy efficiency upgrades to residential buildings. From major health and safety repairs on existing housing to the construction of affordable, energy-efficient homes, money from RGGI is being used in every region of Virginia--and is creating high-paying jobs that cannot be outsourced. Along the Eastern Shore, weatherization provider Project:HOMES was able to use RGGI dollars to help the most vulnerable in this community. But something was standing in the way--hazardous living conditions. While the federal weatherization program helps provide energy-efficient upgrades, homes that require major repairs are disqualified from receiving services. That means weatherization providers have had to walk away, or "defer," houses in such disrepair, leaving those most in need living in unsafe, unhealthy and energy-inefficient homes. This is where the state Weatherization Deferral Repair (WDR) program comes in. This RGGI-funded program works in tandem with the federal weatherization program to provide funds specifically for health and	As discussed in the response to comment 7, we agree that these types of projects are important for protecting public health and welfare; however, RGGI is not the only possible source of funding for these types of projects, nor is it the most efficient or transparent means of obtaining this type of funding.

	safety repairs to help vulnerable citizens qualify for weatherization services. Project:HOMES took advantage of this program to make extensive health and safety repairs to 12 homes. The organization hired more than 30 local subcontractors to fix roofs, repair heating and cooling systems and address major mold, electrical and plumbing problems. Once repairs were made through WDR, those homes received weatherization services through the federal program. Those residents now reap on average 20% savings on their utility bills, in addition to living in safer, healthier homes. The Senior Deerfield Apartments in Crewe VA received $93,195 in repairs, including replacement roofs and new HVAC systems. In Shenandoah County, Community Housing Partners used RGGI funds to help weatherize 52 units of low-income housing and put 24 subcontractors to work in the process. And that's just on existing housing stock. RGGI dollars also provide affordable housing developers the financial capital to build and renovate energy-efficient housing for low-income families. In Charlottesville, Piedmont Housing Alliance was awarded RGGI money through the Affordable and Special Needs Housing program to renovate and build over 230 homes. They are committed to making all future housing units more energy-efficient, but that may not be feasible if RGGI funding disappears. People Inc. Housing Group is building a new, energy-efficient 22-unit complex in Abingdon for low-income families, which will include five accessible units for those with disabilities. The RGGI funding received for this project ensures that these units will be as energy-efficient as possible. RGGI funding is a game-changer for the most vulnerable in our communities. While administration	

	officials have suggested that other funding sources could be found to replace RGGI funds, that would be a herculean task. In 2021, the RGGI auctions brought in millions of dollars more than every other energy efficiency program in the state--combined. Virginians can't afford to have these programs disappear.	
9. Northern Virginia Regional Commission (NVRC)	NVRC strongly encourages maintaining participation in RGGI because of the benefits to northern Virginia and the rest of the state from RGGI funding and programing. RGGI funds and programs have helped make northern Virginia climate resilient, socially equitable and economically sustainable. The 2020 law gave DEQ the authority it had lacked previously--to sell allowances directly into the quarterly RGGI auctions and raise revenue for Virginia. But it also requires DEQ to use that new authority, mandating that DEQ "shall seek to sell 100 percent of allowances" in a trading program consistent with RGGI. Thus, Virginia's participation in RGGI is required by the statute. Therefore, any effort to withdraw Virginia from the RGGI program must be approved by the General Assembly. This position was acknowledged by an Attorney General's Opinion dated January 11, 2022. Participation by Virginia in RGGI has led to the establishment of two important funding sources: CFPF, and HIEE. These programs have been provided vital--and at times the only--financial support to help financially-pressed local governments protect marginalized and low-income communities from economic hardship, health threats and environmental degradation. These funds also promote proactive climate resilient planning that supports public, ecologic and commercial health, rather than costly reactive and unplanned remediation. Local governments in	As discussed in the response to comment 7, we agree that these types of projects are important and necessary. We disagree that RGGI is the best means of achieving them. § 10.1-1330 A of the Clean Energy and Community Flood Preparedness Act does require that the department adopt the provisions of Article 4 into the final regulation previously adopted by the board. However, § 10.1-1330 B then goes on merely to authorize the Director to establish an auction program. This is an authorization, not a mandate, and that provision of the code is therefore discretionary.

	northern Virginia have used and will continue to use these funds to support resiliency planning that aids the operations of our region's hospitals, energy and water infrastructure, schools, businesses, and residences. Withdrawing Virginia from RGGI would seriously limit local governments a vital financial mechanism that cannot be replaced. For example, in RGGI funds from CFPF will support these critical resiliency planning activities in 2022: - $3,241,200 City of Alexandria Waterfront Improvement Project Design - $516,500 City of Alexandria Flood Mitigation, Edison and Dale Street Capacity Project Phase I - $11,250 Northern Virginia Regional Commission, Flood Prevention and Protection Study: Northern Virginia Rain Gauge Network Evaluation Alexandria's waterfront is already highly vulnerable flooding from storm events and sea level rise. Funds from the CFPF will help the city and region prevent loss of property, infrastructure, and economic stress. NVRC analysis points to the current threats from flooding: a rise in the water levels of the Potomac River between 3-5 feet would impact property values of parcels along Alexandria's waterfront between the northern boundary of Jones Point Park and Oronoco Park between $35-100M. The ties between Alexandria's flood protection efforts, affordable housing planning and support from CFPF can also be seen in NVRC's Social and Housing Vulnerable Populations interactive mapping tool. This information indicates that the Alexandria flood mitigation project not only supports flood mitigation, but it also is supporting a socially vulnerable community in need of housing support. Alexandria has one of northern	

	Virginia's largest concentrations of socially vulnerable populations. Alexandria is a majority-minority community with approximately 51.5% of renter households over-burdened by housing costs. Flood mitigation planning like that supported by RGGI and CFPF, give the city greater opportunities to protect the low-income families of Alexandria from the threats of flooding. Despite its affluence, northern Virginia has sizeable concentrations of low-income households vulnerable to high energy costs. NVRC has analyzed the number of households earning below 50% of Area Median Income. It is estimated that there are over 170,000 households below this threshold. Since July 2021, RGGI on a statewide basis has invested $27.8M in funds to help 2335 families residing in affordable housing projects. It is estimated that some of these families have incomes as low as 40% of area median income. RGGI funds via HIEE for 2021-2022 also will help low-income households in northern Virginia receive weatherization services: $1.2M for 80 units in Fairfax County and $2.0M for 163 units in Arlington County Currently, RGGI provides long-term, institutional, and reliable funding across the state. As the stressors from climate change escalate, reliance on RGGI-funded programs will rise. Virginia was the first southern state to participate in RGGI and RGGI-funded programs have helped Virginia reduce carbon emissions, create a more stable business environment, protect the state's infrastructure and improve public health at unprecedented rates. It would be unfortunate to slow or halt this progress.	
10. Virginia Chapter, American	Market-driven reductions in air and water pollution have proven highly successful at preserving a healthy environment for children. Building	The commenters' concerns are acknowledges and shared. As discussed elsewhere, these issues must be addressed;

Academy of Pediatrics	on the success of prior programs in the northeast, RGGI reduces air pollution and thereby protects children's health. The health outcomes of RGGI have been characterized in two studies. The first analyzed RGGI's health effects from 2009-2014. Reductions in air pollution associated with the program prevented adverse health outcomes across the northeast from 2009-2014, including 420-510 instances of acute bronchitis, over 200 asthma emergency department visits, more than 8200 asthma exacerbations, and tens of thousands of lost work days. These and other health benefits have resulted in over $5.7B in health and productivity savings. A second study published in 2020 focused on children and the developing fetus. This study found that from 2009-2014, RGGI-associated reductions in air pollution prevented 537 cases of child asthma, 98 instances of autism spectrum disorder and 112 pre-term births. While reducing criteria air pollutants, the program also has reduced carbon emissions from power plants in participating states by almost 50%, a 90% greater reduction than in non-participating states. Protecting children from climate change is a priority of this organization. RGGI is working to protect the health of current and future children. We therefore support Virginia's continued participation in this program.	however, RGGI participation is not the best approach for doing so.
11. Hampton Roads Planning District Commission (HRPDC)	On behalf of the HRPDC board and 17 member jurisdictions, I write to oppose the proposed actions to remove Virginia from RGGI. HRPDC appreciates the concern regarding the increase in energy costs, part of which are due to the state's participation in RGGI. We recognize that any increase in energy costs places significant burdens on Virginia residents and businesses. Securing more	As discussed in the response to comment 6, a balance must be struck between the need for pollution control to protect public health and welfare, and the reasonableness of the costs needed to achieve it. Energy efficiency and resiliency are indeed important concerns that must be addressed--they must be achieved in the most efficient and fiscally responsible means possible.

	affordable energy will help Virginia remain economically competitive and protect our quality of life. However, we also believe that energy costs cannot be the only factor in reconsidering whether the participation in RGGI continues. Crucially, the NOIRA does not consider that Virginia's proceeds from RGGI auctions fund both the HIEE program and the CFPF. RGGI auctions have provided nearly $430M to these programs since March 2021, funding that would not have been possible without participation in RGGI. The Hampton Roads region is significantly vulnerable to both current and future flooding. The CFPF is the only significant source of state funding for local resiliency initiatives and projects. Having a reliable, ongoing, and adequate funding source is critical for addressing resiliency and flooding issues. Until an alternative source of revenue is identified, any decision to remove the state from RGGI will be premature. The HRPDC therefore opposes the regulatory action. We encourage the Administration to consider Virginia's participation in RGGI in the broader context of resiliency and energy efficiency goals.	
12. Town of Blacksburg	The Mayor and Town Council of the Town of Blacksburg urge the board to reject attempts to remove Virginia from RGGI. Participation in RGGI is already yielding tremendous economic benefit and has put the state on a predictable, market-driven path to a clean energy economy. The 10 other states that have participated in RGGI have reduced climate-warming emissions 90% faster than the rest of the country while growing 31% faster economically. Furthermore, it has been asserted that the board does not have clear authority to take this action as detailed in a recent letter signed by 61 state lawmakers.	As discussed elsewhere, DEQ acknowledges that the impacts of carbon and other forms of pollution must be addressed to protect public health and welfare; there are means of achieving this other than participating in RGGI. See the response to comment 9 for further discussion of the board's authority to address this issue by means of the APA regulatory process.

	Evidence continues to mount that continued inaction on GHG emissions could lead to catastrophic changes for Virginians, destabilizing the systems that support and sustain our communities. Millions of people will experience these changes through threats to public health, disruption of national and local economies, and food and water insecurity. Buildings and infrastructure will be increasingly impacted by the severity and frequency of weather events with enormous response and recovery costs falling on resource-strapped local governments. For coastal communities, these threats will be amplified by rising sea levels. We know that nearly early every element of our society is impacted by energy. A step-wise, predictable transition to a clean energy future will preserve our quality of life, improve economic resilience and foster an ethic of responsible stewardship of our shared natural resources and climate. RGGI provides the state policy framework and structure needed to support that transition. Beyond its climate implications, participation in RGGI benefits Virginia in other ways. Residents of RGGI states enjoy lower energy prices: electricity prices in RGGI states dropped by almost 6% while they went up almost 9% throughout the rest of the country. And RGGI has generated $452M to support much-needed low-income energy efficiency programs and flood resilience infrastructure in Virginia. We urge the board to embrace the numerous economic and environmental benefits of Virginia's continued participation in RGGI.	
13. American Lung Association (ALA) Virginia	We strongly oppose the efforts to repeal the regulation implementing Virginia's participation in RGGI. ALA believes that Virginia must continue participation in RGGI to	The commenter's concerns are acknowledged. As discussed elsewhere, the protection of public health and welfare through the control of GHG and other forms

	make meaningful reductions in GHG emissions that protect the health and well-being of Virginians. Our 2022 State of the Air report revealed that some of Virginia's metro areas were named the top places to live while others had much worse results. Ozone and particle pollution can harm the health of all Virginia's residents and of particular risk are children, older adults, pregnant people and those living with chronic diseases – approximately 140,000 children and 580,000 adults are living with asthma in Virginia. Both ozone and particle pollution can cause premature death and other serious health effects such as asthma attacks, cardiovascular damage, and developmental and reproductive harm. Climate change is one of the most urgent threats to human health of the 21st century. Reduction of harmful pollutants caused by burning fossil fuels is critical to improving the local health today and ensuring a stable climate for future generations. Climate change is first and foremost a public health issue and one that creates disproportionate impacts across Virginia's diverse communities. Climate change is making the job of cleaning our air much more difficult as temperatures rise and drive conditions for unhealthy ozone pollution days, among other health challenges. In 2020, Virginia became the first southern state to join RGGI. The RGGI states have established a regional cap on CO_2 emissions. Over time these caps will decline and so will CO_2 and other harmful emissions. For example, a July 2020 study published in Environmental Health Perspectives concluded, "RGGI has provided considerable child health benefits to participating and neighboring states beyond those conventionally considered. Moreover, those health	of air pollution can be better realized outside of the RGGI program.

	benefits are estimated to have significant economic value." Participation in RGGI allows for CO_2 emission to decline in a planned and predictable way to protect health and safeguard our children's future. Since RGGI started emissions have already reduced more than 50%. Through the auction process, it allows funds to be raised to be reinvested into local communities. When the General Assembly passed legislation authorizing participation in RGGI it also outlined initiatives where the revenues should be invested, including 50% for low-income energy efficiency programs, and 45% for the CFPF to address recurrent flooding and rising sea levels. All people are entitled to breathe healthy air and to be free of the adverse health effects of air pollution, especially those who suffer disproportionate exposure from local sources of emissions. ALA strongly opposes efforts to repeal Virginia's participation in RGGI.	
14. James River Association (JRA)	Every two years, JRA releases a comprehensive assessment of the health of the river and ongoing efforts to restore the James. Our 2021 State of the James report found that the effects of climate change, including heavier and more frequent rainfall, will increasingly impact the overall health of the river and our watershed communities. Virginia's participation in RGGI plays a key role in addressing these impacts by reducing carbon emissions and helping communities prepare for flooding. Absent viable alternatives for an emissions reduction program and dedicated flood resilience funding, removing Virginia from RGGI would leave the river and our communities at greater risk, and we urge you to abandon this path. As a market-based, cap and invest cooperative initiative, RGGI has	DEQ recognizes that the continued health of the James River and our other natural resources is essential, as is the protection of human health. See the responses to comments 4 and 7 for a discussion of program effectiveness, and the availability if sources to fund energy efficiency and resiliency programs.

	produced results. DEQ's report to Governor Youngkin regarding the costs and benefits of the Virginia Carbon Trading Rule and RGGI participation agrees that "the RGGI region has a long track record of emissions reductions . . . Since its inception, RGGI emissions have reduced by more than 50%--twice as fast as the nation as a whole--and raised over $4B to invest in local communities." While Virginia's participation is too nascent for data to show state-specific trends, modeling predicts that RGGI participation, with closure of coal electric facilities and renewable energy generation, will put the state on a path to net-zero carbon emissions by 2045. An emissions reduction program akin to RGGI is not just complimentary but, in fact, necessary to meet our carbon free power sector targets. As DEQ's cost-benefit report makes clear, "[i]n the absence of any such program, emissions may not reduce sufficiently to achieve these goals." Removing Virginia from RGGI would cripple our ability to reach our emissions reduction needs, and it would significantly handicap the resources available for communities facing localized flood risks as a result of climate change. Currently, 45% of the proceeds received from RGGI allowances are invested in the statewide CFPF, the only dedicated state funding for critical flood resilience planning and projects. RGGI is the sole source of revenue for the CFPF and has successfully generated over $203M since Virginia's first allowance auction. Of this amount, nearly $46M has been awarded to localities--$28M of which was to localities completely or partially within the James River watershed. This level of state investment, unheard of until now, is greatly needed by communities from our headwaters to our coastal regions. CFPF, and the RGGI	

	proceeds fueling its success, can remove obstacles for localities needing new sources of investment. For example, CFPF can be used for capacity-building and planning initiatives that most federal grant programs will not support. These planning initiatives will help to identify and prioritize where investments can be most impactful. With these plans in place, localities can go on to pursue larger project implementation funds made available through other state and federal initiatives. CFPF dollars can also be used as a match for federal grant programs, increasing Virginia's competitiveness on the national stage. And one out of every four dollars invested in CFPF is set aside for low-income geographic areas. Gutting CFPF's sole source of funding without a viable, reliable alternative in place would make it much harder for localities, particularly low income communities, to address the current and future flood risks. No feasible alternative to RGGI has been proposed that will maintain Virginia's trajectory toward a carbon-free future and guarantee much-needed state funding for local flood resilience efforts. Accordingly, RGGI remains the best bet for mitigating the impacts of and preparing localities for a changing climate, which will increasingly put our rivers and our watershed communities at risk. We urge DEQ to maintain Virginia's participation within RGGI.	
15. National Parks Conservation Association (NPCA)	Virginia is fortunate to host 22 national park sites. Over 20M visitors come to national parks in Virginia and contribute over $1.5B in economic benefit from tourism. Our parks must have clean, healthy air to thrive. RGGI reduces GHG emissions and improves air quality. Decreased pollution translates into public health benefits for all Virginians. Not only does RGGI improve our public health by improving air quality, it generates	Public health and welfare, including the continuing health of Virginia's national parks, are indeed important, and must be protected from the effects of carbon and other forms of pollution. See the response to comment 7 for a discussion of funding, and the response to comment 6 for a discussion of utility structure reform.

	funding for important programs. RGGI funding allows low-income families to have access to energy-efficient homes and localities to better plan for and prevent the flooding we continue to experience during recurrent coastal storms. Rather than repeal this successful program, we urge you to reform Dominion's current monopoly on utility rates that hurt consumers. RGGI is working in Virginia to clean our air, improve our health, and fund important programs that help our citizens. We urge you to continue to build upon the success of this program by keeping Virginia enrolled in RGGI.	
16. The Nature Conservancy	The Nature Conservancy strongly supports Virginia's continued full participation in RGGI and the full distribution of revenue of RGGI funds as prescribed in Code of Va § 10.1-1330. The benefits of RGGI to the state are numerous. Half of the revenue that Virginia acquires through RGGI auctions is designated for low-income energy efficiency programs, including programs for eligible housing developments, administered by DHCD, which has created the HIEE program with the RGGI funds. 1. Using RGGI revenue to reduce wasted energy through energy efficiency is a direct way to lower unnecessary pollution. Since energy efficiency upgrades are being done on households that could not otherwise afford the upgrades, RGGI is directly causing cleaner air through improved energy efficiency. 2. Through energy efficiency improvements, the HIEE program reduces the high energy bills of low-income households. This is a wise investment in Virginia households. Rather than relying on bill assistance programs which must go on indefinitely, HIEE fixes the underlying root of the problem to help families consume less energy in the first place. 3. The HIEE program can provide health benefits to program	We agree that resiliency and energy efficiency projects are essential for protecting public health and welfare throughout the state, however, we do not believe that the RGGI program is the best way to effectuate such programs; see the response to comments 4 and 7 for further discussion.

	participants. Energy efficiency and weatherization improves ventilation and regulates indoor temperature and moisture, leading to lower rates of asthma, allergies, hypertension, heart disease, and other costly medical conditions. 4: The HIEE program is generating economic benefits by hiring local contractors and subcontractors across the state, creating local jobs that cannot be outsourced. There are two components to the HIEE program. First, DHCD uses HIEE funds to make new Affordable and Special Needs Housing more efficient. This investment keeps this housing affordable while also lowering the monthly energy bills for its residents. The second is the innovative WDR program. DHCD administers the federal WAP to low-income households. However, almost 20% of WAP applicants in Virginia are turned down or "deferred" for this program because their home needs repair before it can support the weatherization. Because the residents do not have the funds to repair the building, it does not qualify for WAP upgrades, perpetuating the cycle of paying too-high energy bills. The WDR program invests RGGI revenue to make those repairs in order to unlock the federal WAP dollars. Given that all the benefits of WAP had previously been out of reach for many, leveraging RGGI revenue to tap into federal dollars is important and should continue. The longer Virginia stays in RGGI and puts RGGI revenue to work as designed, the more these benefits will accrue for society. That's important, because the need to improve energy efficiency for low-income households is huge, and the benefits extend beyond the families living in them. There are no other sources of funds that comes close to matching RGGI if these funds are revoked--in 2021, the	

	RGGI auctions brought in millions of dollars more than every other energy efficiency program in the state, combined. The HIEE program has only just begun. The potential benefits of what it can achieve for Virginians with RGGI revenue is substantial. We ask the board to reject proposals to end Virginia's participation in RGGI.	
17. William Penniman	Climate change and air pollution generally are strongly driven by combustion of fossil fuels, and electric utilities are among the largest sources of those emissions. CO_2 is the largest cause of climate change and must be rapidly reduced if we are to have any chance of protecting our children and future generations from severe harm. The Governor's proposal, the rapidly drafted March 11 report to support it and the Agency Background Document are badly flawed. They ignore the dangers and harms from CO_2 emissions and are based on flawed claims about RGGI, electric utilities and consumers. They also ignore the reality that states participating in RGGI have substantially reduced CO_2 emissions while growing their economies faster than non-RGGI states and while improving health outcomes through reduced pollution from electric utilities. The March 11 report makes many sweeping assertions based on very little actual data. It acknowledges that the availability of data is "limited since Virginia has just completed its first year of participation." It ignores the actual benefits achieved by states that have participated longer in RGGI. The NOIRA Background Document repeats many of the same mistakes and adds a collection of prices-are-rising statistics that have nothing to do with RGGI and its benefits and do not differentiate electricity from other parts of the economy. Indeed, the rising cost of natural gas is a good reason to reduce reliance on	Resiliency and energy efficiency projects are indeed essential for protecting public health and welfare throughout the state from the effects of carbon and other air pollution, however, the RGGI program is not the best way to effectuate such programs; see the response to comments 4 and 7 for further discussion.

	fossil fuels, which is one of RGGI's benefits. The report asserts that "participation in RGGI is in effect a direct carbon tax on all households and businesses." One could more accurately characterize it as a fee for emissions, which all economists would agree is a sensible way to link price to causation in order to mitigate harms from an activity like combusting fossil fuels. Moreover, after surveying the recent climate-driven disasters in southwestern Virginia, the Governor said he intended to fund disaster relief and efficiency programs, which would require taxing Virginians based on income or transactions without any linkage to the CO_2 emissions they cause. That general taxation would cost all taxpayers without the incentives from a carbon-based emission fee. It would be still worse to gut funding designed to help residents to reduce their energy bills through energy efficiency improvements or to gut funding to help communities threatened or harmed by accelerating climate change. Gutting such funding is likely what would result from trying to shift such measures to general taxation. The report claims that "RGGI fails to achieve its goal as a carbon 'cap-and-trade' system because it lacks any incentive for power generators to actually reduce carbon-intensive gas emissions." That claim is built on two other misleading claims: that utilities have no incentive to reduce emissions due to cost-based ratemaking and that customers have no ability to reduce their purchases because Virginia's market has not yet open to full competition. Those claims are wrong for several reasons. (a) Utilities' rates are subject to review for imprudent incurrence of costs which can result in limiting recovery of costs that a prudent utility would	

	have avoided. (b) Utilities always have incentives to grow load, which requires them to seek to mitigate costs. (c) Virginia utilities are directed by existing law to reduce their CO_2 emissions over the next 20 years which fits well with RGGI's system. (d) Small and large customers can reduce their purchases of electricity from utilities through greater energy efficiency or conservation practices, by installing solar on their property or by joining a community solar program. Utility prices, including CO_2 charges, will help to drive those consumer decisions, which is what we want in order to mitigate global warming. The report makes the misleading claim that other states return RGGI revenues through rebates. Most offer rebates to support energy efficiency investments by residents, which is what much of what Virginia would do. Some use funds to support adaptation and recovery measures, which is part of what Virginia would do. It is misleading to imply that most or any other states use most of their RGGI revenues to simply return cash to residents. Although it is possible that CO_2 emission charges will raise utilities' per-KWH rates for sales, that would likely be a temporary impact. As utilities shift to zero-carbon energy sources their operating costs will decline both because wind and solar have near-zero operating costs and because that switch will reduce incurrence of RGGI charges. Also, customers' reduced purchases from utilities through energy efficiency or solar energy would offset rate increases and lower bills, while cutting CO_2 emissions. In other words, RGGI's CO_2 charges will do what they are supposed to do: provide incentives to reduce emissions and mitigate climate change.	

	The report says that Virginia's CO_2 emission rates per MWH have been reduced but "mass emissions levels of CO_2 from the Virginia power sector have remained fairly constant over the last 10 years despite a 30% increase in power production." However, continuing to emit the same total amount of CO_2 as in the past will destroy the future for our children. We need to achieve total reductions to limit the accelerating climate change. It is fortunate that renewable energy options have become the cheapest fuel and that there still remains much that can be done to improve energy efficiency. But there is no guarantee that past trends will continue. RGGI's targeting CO_2 emissions is vital to moving Virginia to the net-zero emissions level. The report and Background Document focus on hypothesized utility rate impacts in a vacuum. They ignore the external costs of fossil fuel emissions to human health and climate harms. The primary recommendation of these documents is to turn the clock back to higher emissions. GHG must be cut now and cut rapidly. Virginia's citizens and economy will be badly harmed by removing RGGI's incentives for more rapidly reducing CO_2 and for accelerating energy efficiency.	
18. Climate Action Alliance of the Valley	We take issue with EO-9, which requires DEQ to re-evaluate Virginia's participation in RGGI and begin the regulatory processes to end it. As we noted in our letter of August 25, 2022 to the Governor, in our view DEQ and the board, cannot legally withdraw Virginia from RGGI. The 2022 General Assembly declined to repeal RGGI; therefore the law stands. As VAEEC noted in its October 13 submission, RGGI is performing as intended and many low and middle income Virginians are benefiting from RGGI's revenues. Other funding sources could be found to replace RGGI funds, but finding	As discussed in the response to comment 9, § 10.1-1330 B of the Clean Energy and Community Flood Preparedness Act authorizes the Director to establish an auction program. This is an authorization, not a mandate. We agree that resiliency and energy efficiency projects are essential for protecting public health and welfare throughout the state, however, we do not believe that the RGGI program is the best way to effectuate such programs; see the responses to comment 4 and 7.

	those funds would be a herculean task. Even if other funding sources are identified, there will be a gap in the forward progress made to date and in all likelihood the new sources would not provide the added benefit of reducing Virginia's carbon emissions. We concur with VAEEC's comments. We provided two opinion pieces addressing our substantive concerns with the proposal for Virginia to withdraw from RGGI. Our January 26, 2022 piece argued that Virginia Should Remain In RGGI; our March 25, 2022 open letter to Valley Legislators pointed out that there is no logical reason to withdraw Virginia from RGGI and that the decision to do so must come from the legislature. We stand by our previous opinions. The RGGI auction proceeds that go to the CFPF is and will remain sorely needed. The Governor has pointed out that the need for community resiliency is real and urgent. RGGI is the sole source of revenue for the statewide CFPF, which represents the only dedicated state funding source for flood resilience planning and project implementation for localities, tribes, and soil and water conservation districts across Virginia. The CFPF provides money for capacity-building efforts not usually funded through federal grants and that CFPF dollars can serve as a match for such programs. The need for long-term planning and action—and funding—for recurrent flooding inland and on the coast is real, ongoing, and increasing. There is no justification for pulling Virginia out of RGGI because critical funding that local governments need would disappear, be greatly reduced or be available episodically subject to annual and biennial decisions. The obvious result would mean disproportionate harm to under-resourced, small,	

	rural cities, towns, and counties who cannot address flood risk on their own. This is no time to deprive the CFPF of the RGGI funds. Doing so would make a mockery of the Governor's publicly expressed concerns for places like Buchanan County and certainly would greatly limit Virginia's ability to assist its many vulnerable localities when the worst happens.	
19. Virginia Clinicians for Climate Action (VCCA)	RGGI protects the health of Virginia residents from climate change and air pollution. VCCA strongly opposes efforts to remove Virginia from the program. Climate change is associated with far-reaching adverse health impacts. Worsening extreme weather events place residents of affected communities at risk of injury, death, disrupted medical services and mental health effects. Longer and more intense heat waves increase the risk of heat-related illness, particularly in the elderly, outdoor workers and athletes. More severe allergy seasons worsen exacerbations of asthma, chronic lung disease, and allergic diseases. Infectious disease patterns shift in response to changing climate conditions. Reducing carbon emissions in order to reduce climate change impacts is imperative to protecting public health. Since its inception, RGGI has effectively reduced carbon emissions from electricity generating facilities. States that participate in the RGGI program have reduced their power plant carbon emissions by 50%, outpacing the rest of the country by 90%. Electricity prices have simultaneously declined in RGGI states while increasing in the rest of the country. In addition to CO_2, fossil fuel combustion releases numerous other air pollutants including fine particulate matter, VOCs, NO_X, and SO_2 that are harmful to human health. Adverse health impacts of air pollution include heart attacks, strokes,	Reducing carbon emissions in order to reduce climate change impacts is indeed imperative to protecting public health and welfare. We note in the responses to comment 4 and 7 that the RGGI program is not the most effective means of achieving these important goals.

	asthma exacerbations, chronic obstructive pulmonary disease exacerbations, and preterm births. These harms disproportionately impact low income and racial minority populations. RGGI is already protecting health across the northeast by reducing toxic air pollution. A 2017 study found that from 2009-2014, RGGI-associated reductions in air pollution prevented 420-510 instances of acute bronchitis, 240-540 instances of adult mortality, 8,200 asthma exacerbations, over 200 asthma emergency room visits, and tens of thousands of lost work days. Prevention of these outcomes resulted in over $5.7B in health and productivity savings. A 2020 study found that air pollution reductions associated with RGGI prevented 537 cases of child asthma, 98 instances of autism spectrum disorder, and 112 preterm births in the northeast from 2009-2014. In addition to reducing air pollution, RGGI protects the health of Virginians by providing crucial funding for energy efficiency improvements to low-income families. Through major health and safety repairs on existing homes as well as the construction of affordable energy efficient homes, revenue from RGGI is being used to improve living conditions for residents across the state. These improvements create homes with reduced indoor pollutants, better controlled moisture, and reduced mold. These improvements lower the risk of heart disease, respiratory disease, severe asthma, COPD, and cancer. Since its implementation, the RGGI program has proven highly effective at reducing harmful emissions and protecting health . VCCA therefore strongly supports Virginia's continued participation in the program.	

20 The Pew Charitable Trusts	Virginia's participation in RGGI is pursuant to the Clean Energy and Community Flood Preparedness Act. Repeal of the regulations governing the state's participation in RGGI without the promulgation of replacement regulations appears to be facially inconsistent with the statutory requirements of existing law and will undermine a key flood-preparedness resource funded by RGGI auction revenue. Injecting uncertainty into Virginia's participation in RGGI would have significant adverse impacts for the state. RGGI auction receipts represent Virginia's sole source of funding for community-scale flood mitigation projects and capacity-building through its resourcing of the CFPF. The Fund has accrued more than $203M and dedicated $46M.The National Institute of Building Sciences research shows investing in mitigation has a national average benefit of $6 to every $1 invested in upfront mitigation costs. The Youngkin Administration has repeatedly raised its commitment to mitigating the risk of flooding to Virginians. Efforts to withdraw from RGGI run counter to this priority, and Pew urges the Administration to reverse course.	DEQ disagrees that this action conflicts with state law; see the response to comment 9. Rather than injecting uncertainty into the electricity market, leaving the RGGI program will protect utilities and their customers from the uncertain outcomes of RGGI auctions. As discussed elsewhere, there are other more transparent and stable means of funding important resiliency and energy efficiency projects.
21. American Council for an Energy-Efficient Economy (ACEEE)	Energy efficiency programs reduce energy costs and protect health, making them a powerful tool for mitigating longstanding inequities experienced particularly by marginalized and underserved communities. Proceeds generated from RGGI's quarterly auctions yield millions of dollars of funding that can be used to invest in energy efficiency programs in historically underserved communities. These investments can help ensure an equitable distribution of benefits and avoid placing disproportionate cost burdens on already disadvantaged communities. In short, RGGI makes energy affordable for low-income	See the responses to comments 4 and 7 for a discussion of the need to fund these types of projects, and the clearest, most effective means of obtaining and distributing funding.

	Virginians, in alignment with the objectives of the 2022 Virginia Energy Plan. In recognition of the importance of investing in energy efficiency for marginalized communities, the Clean Energy and Community Flood Preparedness Act requires Virginia to allocate half of its RGGI proceeds to low-income energy efficiency housing programs. In 2021, these proceeds amounted to $114M. These funds are administered by DHCD and go toward the HIEE program. HIEE provides funding to the WDR program and the ASNH program to tackle energy efficiency improvements for both new and existing housing. The WDR program provides crucial health and safety repairs for homes that have been deferred from the federal WAP. WAP provides funding to make low-income homes more energy efficient, but households are often deferred from the program due to health and safety hazards, that make weatherization difficult or unsafe. Using WDR to address preexisting conditions that need to be remediated prior to weatherization lowers the energy burden for low-income households and allows them to reap the benefits of living in safe homes. The ASNH program uses RGGI dollars to develop new affordable housing and renovate existing affordable housing units. Developers that receive this funding must work to greatly increase the energy efficiency performance of the units. Virginia's participation in RGGI reduces energy bills for the state's most vulnerable residents by offering affordable, healthy, and efficient housing. From 2008–2017, other states that participated in RGGI saw a decline in electricity prices by 5.7% while other non-	

	RGGI states saw electricity prices rise by 8.6% during the same time period. RGGI is also a job creator and improves overall air quality and health from decreased pollution. In 2020 alone, investments in energy efficiency using RGGI proceeds created 1,400–1,500 job-years for states involved in the cap-and-invest program. Other analyses have shown that from 2009–2017, RGGI generated over $4B in net economic benefits and resulted in more than 44,000 job-years. Virginians deserve to have these economic benefits of RGGI, and Virginia should avoid taking steps that will jeopardize these benefits. ACEEE urges the board to reject any efforts to withdraw Virginia's participation in RGGI.	
22. Arlington County Office of Sustainability and Environmental Management	RGGI is a high-performance mechanism for delivery of vital services and benefits to Virginia's citizens and businesses. Participation in this market-based program provides direct, cost-effective benefits addressing energy efficiency opportunities for the vulnerable populations and addressing community resiliency. As a cap-and-investment compact, RGGI: - Benefits utilities with a flexible and responsibly paced instrument for decarbonizing its energy resources that is cost-neutral to the utility - Has kept costs for households low, which is especially important for low-income ratepayers, by distributing the expense of investments and allowing utilities to identify the most cost-effective, high-performance approaches to reduce emissions - Funds Virginia programs that generate benefits and co-benefits at a scale that cannot be otherwise duplicated, at a conversely low-cost-of-government - Creates an investment stream that levels opportunity between high- and low-income communities and reduces profound, near- and long-term risk and cost burdens to Virginia constituents	As discussed in the responses to comments 4 and 7, we agree that these types of projects are important; we disagree that the RGGI program is the clearest, most effective means of obtaining and distributing funding to these projects.

	- Benefits utilities with a flexible and responsibly paced instrument for decarbonizing its energy resources that is cost-neutral RGGI's market-based approach allows utilities to meet electricity demands without requiring a specific mix of generation sources, while allowing for flexible decision-making. Utilities can meet the environmental performance requirements of the program in the most cost-effective manner with the flexibility to plan and phase implementation in a responsible path toward a clean energy resource portfolio. The allowance market enables utilities to optimize their approach to decarbonization, encouraging early GHG reductions through allowance banking and multi-year compliance periods. The cost containment reserve mechanism of RGGI mitigates any risk associated with high allowance costs, thus limiting price volatility so utilities can plan energy generating resources for the future with limited uncertainty. At the same time, RGGI is a tailored, mission-specific program that will cease operation once decarbonization goals and defined outcomes are achieved. RGGI has kept costs for households low, which is especially important for low-income ratepayers, by distributing the expense of investment and allowing utilities to identify the most cost-effective, high-performance approaches to reduce emissions. RGGI costs to ratepayers are exceptionally low, and its benefits to the public represent diverse and substantive returns-on-investment. A study by the Analysis Group found that during the 2015-2017 compliance period, RGGI led to $1.4B in net positive economic activity regionally through investment in energy efficiency, renewable energy, bill assistance, and other measures to reduce GHGs. RGGI has generated over	

	$4B in net economic gain over its first ten years. RGGI auction proceeds have also been used to fund research, education, and job training programs. Further, energy consumers saw a net savings of $220M on energy costs during the 2015-2017 compliance period. Over the first 10 years of the program, CO_2 emissions from RGGI power plants fell 47% regionally while electricity prices in RGGI fell 5.7%, even while prices increased in the rest of the country. The RGGI framework reduces GHGs, as well as other localized pollutants, at low cost. By reducing emissions of NOx, SO_2, and other pollutants that negatively impact air quality, RGGI achieves significant co-benefits in the form of improved public health. A report from Abt Associates found that, from 2009-2014, RGGI saved 300 to 830 lives, avoided 8,200 asthma attacks, and generated $5.7B in health savings and other benefits. Another study found that RGGI avoided 537 cases of childhood asthma. Proceeds from RGGI in Virginia are allocated to the CFPF. In its latest round, this fund provided $13.6M to local and regional governments across the state. This fund awarded over $32M in 2021. RGGI has funded critical, long-deferred investments in flood, encroachment, and subsidence mitigation projects, producing exponentially favorable, long-term returns and substantial reduction of present and future risk. The most recent auction has provided the state $452M in auction proceeds, which have been reinvested in projects and programs benefit residents and businesses across the state. Funding from RGGI auction proceeds unlock investment opportunities that can benefit communities of all income levels,	

	and can be directed to disadvantaged communities. By shifting Virginia's energy system to cleaner, low-carbon, and renewable sources, the state increases energy independence and reduces its exposure to volatility in global energy markets, providing stable energy prices to its ratepayers. These investments create jobs for Virginians. RGGI led to net job creation in all nine participating states from 2015-2017, creating over 14,500 job-years in that period. Over the first 10 years of the program, RGGI created over 44,000 job-years.	
23. Justin M. Wilson, Mayor, City of Alexandria	The City Council of Alexandria urges you to keep Virginia in RGGI. In addition to driving down GHG emissions, which improves air quality and public health, Virginia's participation brings in otherwise unavailable revenue to assist families with energy bills through weatherization funding and flood protection via projects funded by the CFPF. Flooding is the most common and costly natural disaster, and communities across Virginia are experiencing coastal, riverine and stormwater flooding more often, and with greater impacts to homes, businesses, roads, life, health and public safety, than ever before. We know that proactively investing in programs and projects to prevent flooding is a more efficient and effective use of taxpayer dollars than spending on flooding recovery, as exemplified by FEMA research showing that $1 spent on disaster prevention saves up to $7 in recovery costs. Virginia's participation in RGGI provides the sole source of funding for the CFPF, which is currently supported in its entirety by 45% of the revenue generated by our participation in RGGI. To date, the CFPF has granted just over $45M to communities across Virginia in support of flood resilience initiatives and efforts to reduce the impacts of flooding in these communities. But	See the responses to comments 4 and 7 for a discussion of the need to fund these types of projects, and the clearest, most effective means of obtaining and distributing funding.

	the demand far exceeds this level of investment, with over $93M in planning and project requests submitted during Round 3 alone. Localities across the state are working to put the infrastructure in place that can allow our communities to adapt and become more resilient in the face of the impacts of a changing climate. This significant undertaking requires a massive financial commitment that goes far beyond the ability of any single locality to fund with their own resources. As a Commonwealth, we must take advantage of every option to plan for and accelerate this work. This includes the CFPF, which is wholly funded through Virginia's participation in RGGI. In recent years, Alexandria has experienced severe impacts from multiple urban flash flooding events due to intense storms caused by climate change. The Flood Action Alexandria initiative was created in 2021 to accelerate capital projects and operating programs to help mitigate the impacts of flooding caused by these storms. The creation of this initiative coincided with a doubling of the local stormwater utility fee and a shift in resources to develop the Stormwater Management 10-Year Plan to focus on flooding mitigation capital projects and related programs. The city's commitment to investing in flood related infrastructure in Alexandria is clearly reflected in this $197M, 10-year stormwater capacity and spot improvement capital program, with $136M of investment planned over the next five years. In addition to these plans, programs and projects, the city has been awarded approximately $5.5M in CFPF grants, which have allowed us to accelerate these capital projects and bring relief to our community even faster than previously planned. For instance,	

	CFPF funding has allowed the city to begin delivering smaller flood mitigation projects in the equity area of Alexandria well in advance of the FY2026 scheduled funding for the large capacity project planned for this area. In this way, we can protect people and property from flooding ahead of our existing funding schedule while reducing the burden of the stormwater utility fee on rate payers. The CFPF is potentially even more valuable to localities across the state that otherwise would not have the financial resources or professional expertise to even take the first steps toward resilience, including developing flood vulnerability assessments and action-oriented flood mitigation plans. Communities across Virginia need to plan for, mitigate, and build resilience to the climate change impacts being felt today. The dedicated source of funding for the CFPF provided by Virginia's participation in RGGI is critical to our ability to do the work of flood mitigation and resilience planning in our communities.	
24. Levar M. Stoney, Mayor, City of Richmond Virginia	We cannot escape the environmental impacts of climate change that are taking shape in cities across the country, that's why I'm proud of the work that has gone into developing the RVAgreen 2050 plan. This framework is Richmond's equity-centered climate action and resilience planning initiative to reduce GHG emissions 45% by 2030, achieve net zero greenhouse gas emissions by 2050 and help our community adapt to climate impacts of extreme heat, precipitation, and flooding. However, local governments alone cannot solve the climate crisis. RGGI is a commonsense, market-based, cost-effective, and critically important program that cuts harmful carbon pollution while delivering a multitude of benefits to communities across Virginia. The proceeds from RGGI will fund vital	See the responses to comments 4 and 7 for a discussion of the need to fund these types of projects, and the clearest, most effective means of obtaining and distributing funding.

	programs including community flood preparedness and mitigation efforts as well as low-income energy efficiency and housing programs. Richmond has received $1,246,047 in RGGI CFPF funding that is increasing flood protection and improving public safety in some of the most vulnerable and underserved neighborhoods in our community. 80 low-income households in our community are receiving approximately $720,000 in much needed health and safety repairs from the RGGI funded WDR program. The repairs will help these households qualify for weatherization services that will lower utility bills and make the homes more comfortable. I urge the board to continue Virginia's participation in RGGI.	
25. Chesapeake Bay Foundation	RGGI has a demonstrated track record of reducing carbon emissions while funding key climate mitigation needs for the state. Before our participation in RGGI, Virginia had no funding to address the significant and costly impacts of flooding across the state and our energy efficiency programs were substantially underfunded. The cap-and-trade approach of RGGI means Virginia will continually draw down carbon emissions as it moves toward the net zero goals laid out in the VCEA. RGGI provides accountability that the state is taking the necessary steps to meet VCEA objectives while providing the resources to ensure our communities are prepared to handle climate change impacts. We know that cleaning up the bay is a priority for this Administration and so we want to highlight the importance of RGGI to bay restoration. Reducing emissions from fossil fuel production will improve air quality but those same reductions also help improve water quality. Scientists estimate that over one-third of the nitrogen that pollutes the bay comes from airborne	DEQ agrees with the commenter that the Chesapeake Bay is one of our most important natural resources; we disagree that participating in the RGGI program is the most efficient and cost-effective means of obtaining funding for bay protection projects.

	sources. Continuing to reduce NO_X emissions from the burning of coal and gas is a key component of the roadmap to a restored bay. RGGI has a demonstrated record of reducing emissions leading to cleaner air and waters. Climate change impacts such as sea level rise and increased rainfall intensity are already impacting the daily lives of Virginians, but these rising waters are also increasing nutrient and sediment loads to the bay. Increases in water temperature are reducing the bay's ability to hold dissolved oxygen. The Phase III Watershed Implementation Plan estimates 9M pounds in additional nitrogen reductions will be needed throughout the watershed to keep pace with climate impacts through 2025. As we look past 2025, sea level rise and rainfall intensity will continue to increase, bringing additional pollution loads into our waters. Virginia must do its part to reduce global emissions and the RGGI cap and trade approach ensures our numbers will continue to decline in the years ahead. Funds from RGGI are already helping communities across the state respond to climate impacts through the CFPF. The CFPF is the only source of state funding for resilience planning and project implementation, with 100% of those funds coming from RGGI auctions. RGGI has provided more than $200M to the CFPF since Virginia began receiving auction proceeds in 2021. As of today, nearly $46M has been awarded to more than 40 localities. CFPF funds capacity-building initiatives that most federal grant programs do not, providing necessary planning resources that allow localities to pursue larger projects. Grants from the CFPF can also be used as a local match for federal grant programs, making Virginia applicants more competitive for national programs.	

	Without a reliable, long-term funding source like RGGI, localities will be unable to complete flood resilience planning, studies, and implementation they need to address flood risk. CFPF also prioritizes the implementation of nature-based solutions. Major living shoreline projects, that would have otherwise not been built, will now be cleaning Virginia waters while protecting the communities around them. Our participation in RGGI supports bay restoration by funding practices that protect and enhance our waters. Without RGGI revenues localities would be forced to turn to funding sources that do not prioritize nature-based design, or worse, forego adaptation work entirely. Many of the historic approaches to water quantity have negative impacts on water quality which leads to additional financial obligations for the state. RGGI proceeds to the CFPF have an excellent return on investment to the state by prioritizing both safe communities and clean water. CFPF saves Virginia money on disaster response. The goal in building resilient communities is to avoid the catastrophic outcomes and costs in the aftermath of a flood disaster. A recent study from Old Dominion University estimated that sea level rise could cost the state $79B by the end of the century without significant intervention to assist localities. This study was limited to coastal communities but, as we have all seen in Buchanan and elsewhere, climate impacts are not limited to the shoreline. RGGI proceeds are benefitting Virginia taxpayers by addressing the pressing needs of today and mitigating the potential for crushing costs in the future. The Clean Energy and Community Flood Preparedness Act (§ 10.1-1330) includes a strong directive	

	for Virginia to participate in RGGI. We are concerned that any regulatory effort to remove Virginia from the program without clear legislative approval would be in contravention of the legislation, causing confusion, risking litigation, and undermining the deference otherwise due to DEQ.	
26. Center for Climate and Energy Solutions (C2ES)	Virginia's participation in RGGI is key to reaching the state's target of 100% clean electricity by 2050 under the Clean Economy Act. Without complementary policy like RGGI, compliance costs to meet this target will be higher. Nationally, RGGI is crucial to achieving net-zero economy-wide GHG emissions by midcentury, a necessary target to avoid the most catastrophic effects of climate change both in the United States and globally. Carbon pricing is an efficient and cost-effective way to reduce emissions because it creates accountability for environmental costs while allowing flexibility in how companies meet their obligations. Specifically with cap-and-trade programs like RGGI, policymakers can identify the proper emissions target and allow the cap to determine the most efficient price to achieve that level of abatement. Rising carbon prices increasingly unlock investments in mitigation that would have seemed uneconomical in the absence of a carbon price. Importantly, carbon pricing programs generate significant revenue that can be used to offset energy price increases for lower-income households and further support investments in technologies and programs that reduce emissions. In the case of RGGI, much of this revenue has been reinvested either in direct bill assistance for consumers or in energy efficiency measures that directly save households and businesses money. The benefits of implementing market-based	As discussed in the response to comment 7, programs to reduce carbon through direct emissions reductions and energy efficiency, and to mitigate carbon pollution through resiliency projects, are important--and expensive. Participation in RGGI is not the best means of achieving these goals in the most efficient, transparent, consumer-friendly means.

	programs rather than standalone command-and-control regulatory programs are that they provide greater compliance flexibility for covered entities and allow the market to determine the lowest-cost means of producing the greatest emissions reductions. Over the history of its operation, RGGI has demonstrated success in both reducing emissions in participating states while producing economic benefits and creating jobs. Between 2009-2020, RGGI states reduced their power sector emissions 50% from 2008 levels, a rate significantly higher than the nation's aggregate power sector emissions reductions of 39 percent during the same period. During the first three compliance periods, RGGI is estimated to have yielded a net benefit of $4.7B and more than 40,000 job years to the participating states. In 2020 alone, RGGI invested $196M across all participating states in energy efficiency, clean and renewable energy, beneficial electrification, GHG abatement, and direct bill assistance. These investments delivered more than $37Mn to 720,000 households and 38,000 businesses in direct bill assistance in 2020 and an estimated $2B in energy bill savings over their lifetime for 65,000 households and 800 businesses. Since Virginia's first auction in 2021, Virginia has received more than $452.2M in proceeds from the quarterly sale of allowances. Half of the revenue is directed toward low-income energy efficiency programs and 45% to the CFPF. Energy efficiency programs like WAP have demonstrated histories of success in reducing customers'' annual energy costs by an average of 12%, making this funding central to reducing low-income customer energy bills, rather than raising them. Support for community resilience is also increasingly	

	urgent. From 2017-2021, the total costs for weather and climate-related disaster events totaled over $788B, more than one-third of the total disaster cost of the last 43 years. With 70% of the state's population residing in coastal Virginia, funding for flood preparedness through RGGI will offer significant relief to a large portion of the state.	
27. Virginia League of Conservation Voters (VaLCV)	The VaLCV opposes removing Virginia from RGGI. Virginia's participation prevents pollution that has increased asthma rates among children, contributed to increased flooding, more frequent severe storms, rising energy costs, and deadly heat waves. At the same time, investments made from RGGI proceeds collected from pollution-emitting power plants return hundreds of millions of dollars to the state every year. These proceeds provide a market-based incentive to transition energy generation to cleaner sources while helping lower energy costs for Virginians in need and assist vulnerable localities in adapting to and mitigating flooding and sea level rise in their communities. Participation in RGGI is required by law and consistent with the official Commonwealth Clean Energy Policy (§ 45.2-1706.1) which aims to produce 30% of Virginia's electricity from renewable energy sources by 2030 and 100 percent of Virginia's electricity from carbon-free sources by 2040. RGGI has a proven track record of success, helping cut pollution at its source and reducing energy cost and volatility–driving our clean energy transition in Virginia. The data affirming RGGI's pollution-reduction success is clear, as the March 11 report issued by DEQ states: "RGGI has a long track record of emission reductions since the beginning of the program." Comparing EPA data from 2020-2021, Virginia's RGGI program slashed energy sector air pollution	See the responses to comments 4 and 7 for a discussion of the need to fund these types of projects, and the clearest, most effective means of obtaining and distributing funding. The legal authority for this regulatory action is detailed in the response to comment 9.

	by 14% in its first year. What's more, while Virginia is a relative newcomer to RGGI, in the decade-plus the program has been in operation, RGGI states have reduced climate-warming emissions reduced power plant carbon emissions by 50%, 90% faster than the rest of the country - while seeing 31% faster economic growth than non-RGGI states. RGGI is a core driver of the domestic clean energy economy, currently bringing good-paying jobs to Virginia. These jobs can benefit from emerging workforce development initiatives that transition those who were excluded from previous economic booms into meaningful, good-paying careers. RGGI directly incentivizes zero-carbon producers who benefit doubly from being able to sell electricity in the generation market at a more competitive price than carbon-emitting sources, and from selling their excess carbon allowances to polluters. This has led to a rapid expansion of clean energy jobs, as well as jobs in energy efficiency. The 2022 U.S. Energy and Employment Report shows the energy sector experienced positive job growth, increasing 4.0% from 2020-2021, outpacing overall U.S. employment. In Virginia, energy jobs increased by 8,330 jobs (4.9%), with 73,119 Virginians employed in energy efficiency. Of the 16,321 Virginians employed in power generation, over 60% (10,001) are employed by zero-carbon facilities. RGGI improves public health. Decreased air pollution results in fewer asthma attacks, premature births, and missed days of school and work. In 10 years, participating states realized $5.7B in public health benefits thanks to RGGI. These harmful pollutants are often concentrated in low-wealth and marginalized communities located more closely to emission sources–	

	causing these communities to experience higher rates of heart attacks, strokes, and asthma. Virginia uses RGGI proceeds to actively mitigate the impact of climate change for those most exposed to its effects, be it through flooding in the mountains, sea level rise along the coast, or rising energy costs during extreme heat events. These funds are designed to be disbursed equitably with an estimated 60% of total proceeds dedicated to helping either low-income individuals directly, or low-income communities. Since its first auction in March of 2021, RGGI has generated approximately $452M in cumulative proceeds. Half of these funds–paid for by polluters for each ton of CO_2 their facilities emit–help provide safe, affordable and energy-efficient homes to low-income families in ways that were never possible before RGGI. Thanks to the energy efficiency investments made to date, including $196M in 2020, consumers are on track to save $15B on their electric bills. Virginians also save money over the long term by reducing our reliance on costly fossil fuels. This summer, Virginians' monthly electric bills increased by $17-25 just to pay for the rising fuel cost associated with coal and methane gas. The RGGI-induced shift from high-cost fuels to zero-carbon sources of electricity with no fuel cost is part of the reason electricity prices have declined in RGGI states while increasing in the rest of the country. Reliance on zero-fuel-cost sources also reduces price volatility, making energy bills more predictable, in addition to more affordable. Forty-five percent of these proceeds provide flexible statewide funding dedicated to localities to plan for and prevent recurrent flooding through the CFPF. RGGI is the sole source of revenue for the statewide CFPF,	

	which is the only dedicated state funding source for critical flood resilience planning and project implementation for localities, tribes, and soil and water conservation districts across Virginia. Of the $203.5M RGGI has generated for the CFPF, nearly $46M has been awarded to more than 40 localities. There is a massive need for this funding. If left unchecked, flooding damages are projected to cost the state $79.1 B. The CFPF funds capacity-building initiatives that most federal grant programs do not, providing critical planning resources that allow localities to pursue larger project implementation requests. The CFPF can also be used as a local match for federal grant programs, making Virginia applicants more competitive for national programs. Without a reliable funding source like RGGI to keep money flowing in the CFPF, localities will be unable to complete necessary flood resilience planning to address current and future flood risk. Notably, 25% of CFPF monies are set aside for low-income geographies and the CFPF prioritizes implementation of nature-based solutions. Small and rural communities already experiencing increasing flood risk can't afford to leave this money on the table. Participation in RGGI is the product of a legislative mandate and the culmination of years of research and review. Starting in 2016, a workgroup with extensive stakeholder engagement produced recommendations for reducing carbon emissions from electric power facilities, concluding in its final report that it is "important and necessary that Virginia work through a regional model, like the established and successful RGGI, in order to both achieve lower compliance costs and address the interstate nature of the electric	

	grid." DEQ then engaged in a multi-year process of developing regulations to regulate carbon emissions from power plants through market-based means, trading allowances through a multi-state program. The original rulemaking began in 2018 and in 2020, the General Assembly passed a law requiring Virginia's participation in RGGI. Following these new requirements, the revised final regulation took effect July 2020. Governor Youngkin lacks the authority to take us out of RGGI through the regulatory process. In addition to being the culmination of a multi-year regulatory endeavor supported by a data- and stakeholder-driven report, our participation in RGGI is mandated by policies the General Assembly passed in 2020. According to an official advisory opinion from the Office of the Attorney General released January 11, 2022: "The Virginia Constitution is clear: the Governor does not have the authority to single-handedly repeal or eliminate a law or regulation that has been passed by the General Assembly." RGGI is consistent with official state policy and has clear benefits to the environment, public health, and state economy. We must not seek to take away the best and only tool Virginia has to simultaneously address climate change-inducing pollution at its source, while helping Virginians deal with effects of climate change.	
28. City of Fairfax	The Environment and Sustainability Division urges the Administration to remain a member-state under RGGI, as a high-performance mechanism for delivery of vital services and benefits to Virginia's citizens and businesses. This market-based program provides direct, cost-effective benefits addressing energy efficiency opportunities for the vulnerable	See the responses to comments 4 and 7 for a discussion of the need to fund these types of projects, and the clearest, most effective means of obtaining and distributing funding.

	populations and addressing community resiliency.	
29. City of Hampton	Currently, proceeds from RGGI allowance auctions are the sole source of funding for the CFPF. Since March 2021, RGGI has generated more than $203.5M to enable the CFPF to provide grants and loans to localities throughout the state in support of resilience projects. These funds have provided a meaningful source of financial support for localities throughout the state. Cities, towns and counties need substantial resources to adapt to changing realities of flooding driven by sea level rise, as well as shifting patterns of precipitation and storm events. The scale of this need is illustrated by the number of applications and awards CFPF has seen to date. To date, 76 applications have been awarded funds, while an additional 32 applications were selected for supplemental review. Like many localities, Hampton's existing challenges with flooding are expected to become more severe in years to come. According to modeling completed for the Virginia Coastal Resilience Master Plan, in the next forty years as much as 65% of the city's land area will be at risk of flooding from coastal events alone as a result of sea level rise. Low-lying roads and land throughout the city are already regularly underwater with nuisance tidal flooding as a result of our changing climate. Hampton has dedicated significant local resources to holistically address the increasing challenge of recurrent flooding, sea level rise, and shoreline erosion. Efforts have included completing multiple local resilience plans and identifying dozens of new implementable projects to reduce the impacts of flooding to our community now and into the future. At the same time, we must continue to invest in maintaining the city's aging	See the responses to comments 4 and 7 for a discussion of the need to fund these types of projects, and the clearest, most effective means of obtaining and distributing funding.

	infrastructure to ensure it remains functional in the face of these threats. The city's stormwater infrastructure network struggles to keep pace with increasing stormwater loads and tidal backflow. The financial burden associated with monitoring and planning for changing flooding impacts, adapting public infrastructure and lands to reduce the severity of flooding, and protecting citizens from these natural hazards far surpasses the City of Hampton's available financial resources. The scale of this challenge requires that localities, Planning District Commissions, the state, and the federal government come together to identify multiple pathways by which the built and natural environment will adapt. Hampton is grateful to have received 7 awards totaling more than $9.5M from the state through the CFPF to date. This funding option has provided us with a financial tool with fewer barriers and greater opportunity for success when compared to federal-level funding opportunities. As a result, we are advancing needed projects that are aligned with the Commonwealth's stated values and goals for coastal resilience more quickly, and are able to dedicate our limited financial resources to other identified project needs. The City of Hampton urges the Administration to continue to build upon the success of the CFPF by either keeping Virginia enrolled in RGGI, or to otherwise ensure that there remains a dedicated source of revenue to finance the CFPF, thus continuing to serve all Virginian citizens through flood mitigation benefits.	
30. William Nuckols, Town of Colonial Beach Planning Commission	As a part of my work as a Commissioner on the Planning Commission, I also head up our Resilience Committee, and as such I've come to know of the great disparity between the need and the	The commenter's concerns are recognized. The responses to comments 4 and 7 provide a discussion of the need to fund these types of projects, and the clearest, most effective means of obtaining and distributing funding.

	ability to fund projects relating to resiliency, particularly those relating to planning and addressing persistent problems of erosion and flooding in our community. I write in support of the continuation of Virginia's participation in RGGI as the linkage between the funding made available from the RGGI auctions and the funds distributed from the state to address serious funding shortfalls for resilience projects to be both logical and appropriate. We have not yet been in a place to receive RGGI funds, not because the town does not need the funding support--quite to the contrary, our needs as a coastal town to be resilient in the face of changing conditions is great. Our lack of RGGI awards is solely because our professional staff is significantly smaller than some of the larger cities who have already been awarded funds to address their coastal resiliency issues. Our town may have not yet been in a place to request funding from the state thus far, but intend to do so if the RGGI funding continues. Removing Virginia from RGGI will eliminate a crucial funding stream that can be applied to address the needs of the Colonial Beach and numerous small to medium size coastal communities like ours. While there are smaller programs that can help communities such as ours, none operate at the scale of that the RGGI fund can support. Our needs are in the millions, and so far only the RGGI program is operating at a scale that can address that level of need. I find the linkage between the rationale for the RGGI collection of funds and the use of those funds as administered by DCR. The linkage between the RGGI auctions and the resulting funds raised to address strengthening Virginia's resilience is strong and appropriate. Terminating the RGGI program in Virginia before less	

	affluent towns and counties have even had a chance to apply for RGGI funding support is not appropriate. The town needs both time to apply and the continuation of the increases to the fund from RGGI auctions. EO-9 poses that "benefits of RGGI have not materialized," and while that statement may be accurate in some sense, in large part it is because not enough time has passed to allow the need of impacted communities to receive the impact funds from the RGGI program in terms of shovel in the ground projects. Cutting off participation in RGGI now leaves our town, and small to mid-size communities like it, without any opportunity to realize the benefits of RGGI Don't kill the program before it matures enough to have a positive impact on communities such as ours. While the Governor is proposing to end Virginia's association with RGGI, neither the Director of DEQ, the Secretary of Natural and Historic Resources, nor the Governor's office have made any indications where the loss of funding from the RGGI auctions will be made up. Will there be proposals forthcoming to increase the tax burden on Virginians to made up for the loss in RGGI funds, or is the likely outcome that much needed funding for coastal resilience and flood prevention will simply dramatically shrink, leaving our people and our economy more vulnerable as a result? I fear that without RGGI there simply is no funding source available at the scale required to address the threats to Virginia from an evolving level of threats that the RGGI funds could mitigate. I ask that you please reconsider any decisions that would remove Virginia from RGGI and thereby cut off the funding stream that is so greatly needed to address a multitude of projects our town needs to	

	complete to ensure the sustainability of our historic coastal community.	
31. Southern Environmental Law Center (SELC)	Virginia's emissions reduction program took years to develop over multiple administrations. In 2016 then-Governor McAuliffe issued an executive order directing the Secretary of Natural Resources to establish a work group to study and recommend methods for reducing CO_2 emissions from the electric power sector. After almost a year of public engagement, the work group submitted its recommendations. Based on those recommendations, Governor McAuliffe issued an executive directive in 2017, which instructed DEQ to develop regulations to "abate, control, or limit carbon dioxide emissions from electric power facilities" using "market-based mechanisms" that allow for the "trading of carbon dioxide allowances through a multi-state trading program." DEQ and the board engaged in a multi-year public regulatory process that included two rounds of public comment and multiple revisions to the proposed trading program. The board ultimately approved a version of the program in 2019, although the original program's implementation was delayed due to a budget restriction in the state's 2019 budget. This original program used a consignment model, whereby DEQ would have distributed Virginia's allowances to existing power plants in proportion to their historical emissions but would not sell those allowances directly at auction. Had this been the end of the story, future administrations could have changed course by following regulatory processes without involvement of the General Assembly. The original program had been promulgated under the board's general regulatory authority, so in theory, the program could have been modified or repealed under the same general authority. But that is not the end of the story. In 2020, the General Assembly removed the budget restriction and passed a law	The commenter's summary of the background of activities leading to Virginia's current participation is appreciated. Since then, Virginia's participation in the program to date has been evaluated, and it has been determined that Virginia's participation is no longer needed. As discussed elsewhere, funding for energy efficiency and resiliency programs need not be tied to participation in RGGI.

	specifically about Virginia's Emissions Reduction Program and participation in RGGI. The 2020 Clean Energy and Community Flood Preparedness Act requires Virginia to issue the Emissions Reduction Program and participate in RGGI and requires the proceeds from the sale of Virginia's allowances to be used to help low-income families reduce energy bills and localities address recurrent flooding issues. In other words, the General Assembly decided as a matter of law that Virginia would participate in RGGI. The program was no longer subject only to the board's general regulatory authority, but also the specific requirements of the 2020 law. To comply with the new law, DEQ revised the existing 2019 program. Recognizing that the program had already gone through extensive public rulemaking, and had already been delayed a year, the General Assembly expressly exempted this revision process from the APA and required DEQ to issue the revised regulation directly. This exemption meant that the revision did not require public notice and comment, nor did it require board approval. DEQ followed the requirements set forth by the General Assembly and issued a revised regulation establishing the current program in August 2020. Since January 2021, power plants in Virginia must account for their carbon pollution in accordance with the emissions reduction program. Knowing that the supply of these allowances steadily reduces each year, power plant owners and operators must figure out the most cost-effective ways to reduce their emissions over time. Virginia's program is a critical tool to address a major cause of climate change. It also complements another piece of legislation the General Assembly passed in 2020, the VCEA, which sets forth a pathway for a carbon-free electricity sector by mid-century. Virginia's participation in RGGI helps ensure Virginia fulfills the requirements of the VCEA in a sensible, cost-	

	effective way. The program benefits all Virginians in numerous ways: - Through its proven market-based mechanism, the program is working to drive down air pollution and improve public health; - Continued participation in RGGI will help protect customers from rising fossil fuel prices as power plant owners reduce reliance on fossil fuels; - Low-income households are getting their homes weatherized and getting the energy bill relief they need; - Highly efficient affordable-housing units are under construction to help fill the severe affordable-housing gap with units that will come with low energy bills for tenants; and - Localities have access to a dedicated state fund to help address the increasingly devastating flooding that is happening across the state. Undoing the program would severely hamper efforts to reduce air pollution and improve public health, and definitively eliminate those important sources of funding.	
32. SELC	On December 8, 2021, prior to taking office, then-Governor-elect Glenn Youngkin announced his intention to withdraw Virginia from its participation in RGGI. On January 11, 2022, then-Attorney General Mark Herring issued an official advisory opinion concluding that "the Governor may not repeal or eliminate, through an executive order or other action, the enacted statutes and regulations pertaining to the Commonwealth's participation in the Regional Greenhouse Gas Initiative and/or a market-based trading program like the Regional Greenhouse Gas Initiative, or do away with the requirement that electricity producers hold carbon dioxide allowances that equal the amount of their carbon dioxide emissions." As the opinion explains, the "Constitution of Virginia does not grant the Governor the power to	The summary of past actions relevant to Virginia's participation in RGGI is recognized. The purpose of the current regulatory action is to move the Commonwealth forward in a direction that will improve our ability to develop, fund, and implement these important programs in an efficient, cost-effective, and transparent manner.

	suspend laws, and in fact, it requires the opposite that '[t]he Governor shall take care that the laws be faithfully executed.'" In addition, the opinion cites Article I, Section 7 of the Constitution of Virginia, which provides "[t]hat all power of suspending laws, or the execution of laws, by any authority, without consent of the representatives of the people, is injurious to their rights, and ought not to be exercised." On January 15, 2022, the Governor was sworn into office. That same day, he signed EO-9. Rather than attempting to withdraw Virginia from RGGI directly by executive order--which according to former Attorney General Herring would violate Virginia's Constitution--the Governor asked the board to repeal the underlying regulation. Specifically, EO-9 asked the Director of DEQ to develop two repeal tracks for board approval. The first track (Directive 2) involved a proposal to repeal Virginia's program using emergency regulatory authority, i.e., without the normal public comment period, and the second track (Directive 3) involved initiating a full rulemaking process to make the emergency repeal permanent. EO-9 also requested that DEQ create a "report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data, within 30 days." On March 11, 2022, DEQ provided that report to the Governor, which included a draft proposed emergency regulation and a draft NOIRA for a permanent regulation. Attempts to repeal the underlying law failed in the 2022 General Assembly. Meanwhile, on the regulatory track, the administration took no action for nearly six months, despite the claim that repealing RGGI was so urgent it warranted an unprecedented use of	

	the board's emergency regulatory powers. Finally, at the August 31, 2022 board meeting, Acting Secretary of Natural and Historic Resources Travis Voyles announced that the administration had abandoned the emergency regulatory approach and instead would be moving forward with plans to repeal the regulations through the normal APA process, with the goal of withdrawing Virginia from RGGI by the end of 2023. The administration subsequently published a NOIRA in the Register on September 26, 2022, which proposed the development of a regulation to repeal the program.	
33. SELC	As a policy matter, the current administration does not favor Virginia's participation in RGGI. We disagree; the benefits of Virginia's participation in RGGI are clear and backed by a long track record of success. Regardless, neither we, the administration, nor the board gets to decide this policy. The General Assembly decided Virginia's policy in 2020, when it passed the Act and thereby required Virginia's participation in RGGI. As such, it is the board's responsibility to implement this law, not contradict it, which is what repealing the regulation would do. Multiple provisions of the Act make clear that Virginia must join RGGI and that the regulation cannot simply be repealed. Foremost, the Act specifically requires DEQ to issue and implement the regulation establishing the program. The Act mandates that DEQ incorporate the provisions of the Act into the regulation, without any further action by the board or need to undergo regulatory review under the APA, thus giving DEQ and the board no discretion about whether to adopt the regulation. The law expressly requires it. The Act then grants DEQ the authority it had lacked previously: to sell	The commenter's discussion of former administration activities is appreciated. The legal authority for this regulatory action is discussed in the response to comment 9.

	allowances directly like every other state participating in RGGI. The very next sentence then mandates that the Director of DEQ actually use this new authority, requiring the Director to sell the allowances in the RGGI auctions. The Act goes on to require that DEQ and other agencies "prepare a joint annual written report describing the Commonwealth's participation in RGGI, the annual reduction in greenhouse gas emissions," and the use of revenues collected from RGGI auctions--further indicating the General Assembly's intent that Virginia would join RGGI. The Act is thus unequivocal. The General Assembly required the issuance of regulation and mandated that Virginia participate in RGGI. And in 2020 and 2021, agency officials did exactly what the law required. DEQ revised the program as required by statute, and Virginia began participating in RGGI. Pursuant to the General Assembly's mandate, Virginia is selling 100% of its allowances in the RGGI auctions and using the proceeds to help Virginians as specified in the statute, while power plant owners and operators are acquiring the necessary allowances to account for their carbon pollution. Repealing the regulation would contradict the law. Most evidently, the administration has no authority to repeal a regulatory program that the law specifically required to be issued and implemented. And without the program, numerous other statutory provisions will be violated. Virginia will not generate allowances for the Director to sell at auction. The state treasury will be unable to distribute funds in accordance with the statute. The applicable agencies will be unable to report on the state's participation since Virginia will not be a participant. Not only would the repeal under consideration violate the Act, any decision to do so would also amount to a	

	constitutional violation. The board may not suspend or ignore the execution of laws, nor invade the General Assembly's legislative power, including taking actions contrary to statute, which is what repealing the regulation would do. Even though the text of the Act clearly establishes that Virginia must join RGGI, Governor Youngkin nevertheless takes an opposing view, suggesting in public news reports that the Act merely gave DEQ the discretion to decide whether to participate in RGGI. This argument is based on just one sentence of the Act and ignores the fact that the Act specifically mandates the issuance of this regulation, and every other portion of the Act clearly mandates that Virginia participate in RGGI. The Governor's interpretation is a nonsensical reading of the statute that renders provisions of the law meaningless and adds qualifying language to mandatory requirements where no such qualification exists. Not only is the language of the Act clear, contemporaneous statements from lawmakers and regulators clearly show an intention and expectation that the law itself required DEQ to adopt the program so that Virginia would participate in RGGI. For example, after the Act was put on the Governor's desk, then-Governor Ralph Northam issued a press release stating: "The Act establishes a carbon dioxide cap-and-trade program to reduce emissions from power plants, in compliance with the Regional Greenhouse Gas Initiative (RGGI). The Department of Environmental Quality will establish and operate an auction program to sell allowances into a market-based trading program." David Paylor, then Director of DEQ, made similar statements about how the Act required participation in RGGI, as did Senator Lynwood Lewis, a co-sponsor of the legislation.	

	Moreover, a group of over 60 members of the General Assembly, most of whom were members who voted on the Act, recently sent a letter to the board reiterating that Virginia is required by law to participate in RGGI. The Governor's flawed interpretation is also diametrically opposed to the prior positions of DEQ, the board, and the Attorney General's Office. For example, after DEQ issued the regulations establishing the program, the Virginia Manufacturers Association (VMA) challenged the program, asking the Circuit Court for the City of Richmond to declare the program null and void. VMA argued that DEQ had "the optionality to comply with the Act by joining RGGI, another carbon trading program with an open carbon trading market, or by simply implementing the Original Trading Rule," and that therefore those discretionary decisions were not exempted from administrative process. The trade group also argued that the program was an unconstitutional tax and void due to vagueness. In defending the program, the Attorney General's Office explained repeatedly that the Act did not merely provide DEQ with discretionary authority to run a direct auction program; rather, the Act mandated that DEQ actually use such authority by selling the allowances at auction. The court agreed with the Attorney General's Office and denied the VMA challenge in its entirety. Similarly, the Attorney General's Office has also issued opinions concluding that the Act required DEQ to adopt and implement the Emissions Reduction Program, including selling allowances at RGGI auctions--and that this requirement could be reversed only by an act of the General Assembly, not by the Governor, DEQ or board. As these statements show, lawmakers, regulators, and the Attorney	

	General's Office have all consistently understood that the law requires Virginia's participation in RGGI. There is simply no basis for the current administration to take an opposing view--a view that sharply contradicts the law's plain language and the well-established understanding of the law as set forth by numerous officials and lawmakers, and in official court filings. The administration may not repeal the regulation or withdraw Virginia from RGGI absent legislative consent.	
34. SELC	The administration also asserts that the state must leave RGGI because "the benefits of RGGI have not materialized" and RGGI is placing "a substantial burden" on Virginians in terms of higher electricity costs. Both assertions are disingenuous. Virginia has been part of RGGI for less than two years, so it is far too early to reach definitive conclusions about its success. Nevertheless, Virginia has already experienced substantial benefits from participating in RGGI, including reduced emissions (and corresponding improvements in public health) and hundreds of millions of new dollars in dedicated funding for flood prevention, weatherization of low-income homes, and construction of efficient affordable housing. Other RGGI states have experienced similar drops in emissions while maintaining solid economic growth, which indicates that the net benefits to Virginians will only continue to increase in the years to come. Moreover, while we share the administration's concerns about high electricity bills for Virginians, repealing the regulation in no way fixes that problem. Those increases are due to various non-RGGI factors, most notably increases in fossil fuel costs. And, more importantly, the appropriateness of electricity rates is a question for the General Assembly and the SCC--the body the General Assembly has put in charge of evaluating	As discussed in the response to comment 7, the costs of any carbon reduction program will be borne by the state one way or another. We suggest that these costs be managed in the most transparent way possible.

	utility rates. The board and DEQ should be focusing on its charge, namely, abating air pollution. Given that DEQ has said participation in RGGI is necessary to meet the Commonwealth's emissions goals, there is no reason to repeal the regulation and withdraw from RGGI, even if the board had the authority to do so. Perhaps the most important benefit of participating in RGGI is that it will help drive reductions in power plant emissions in Virginia, which represent roughly 30% of the CO_2 emissions in the state. According to DEQ, "an emission reduction program or combination of programs will be required to meet the Commonwealth's climate goals of the [Virginia Clean Economy Act] and the 2045 net-zero carbon emissions goal. In the absence of any such program, emissions may not reduce sufficiently to achieve these goals." Continued participation in RGGI is thus vital to reducing emissions and ensuring that the state meets its climate goals. Moreover, meeting that net zero goal is critical for helping Virginia avoid the worst impacts of climate change. Left unmitigated, it is estimated that sea level rise will cost the state about $56B in financial damages and lead to a $79B decline in economic output by the end of the century. Sea level rise also could place as many as 400,000 Virginia homes and 900 miles of roads in the Hampton Roads area at risk from storm surges, and it would cost hundreds of billions of dollars to replace those homes and roads. Climate-related shifts in precipitation and weather are also expected to cause water shortages in roughly half of Virginia's counties, potentially imperiling agriculture, which is Virginia's largest industry, supporting almost 311,000 jobs with an annual economic impact of $52B. All of these harms are being mitigated by Virginia's participation	

	in RGGI, both by driving down climate changing emissions and by bringing in critical funding for flood planning and projects. Given those long-term needs and goals, it makes sense that the General Assembly would want to ensure that Virginia participated in RGGI. The entire purpose of RGGI is to reduce emissions in participant states, and it has been effective in achieving that goal. As the current administration has acknowledged, "the RGGI region has a long track record of emission reductions since the beginning of the program" The nine states that have participated in RGGI from the outset saw their power plant emissions collectively drop more than 50% between 2009-2020. That net reduction is approximately 90% more than the rest of the U.S., showing that RGGI participation is a key driver of emissions reductions from power plants. Before joining, Virginia, like the other non-RGGI states, did not see its power plant emissions decline during that period. According to DEQ's EO-9 Report, between 2010-2020 (before Virginia joined RGGI), mass emissions for the power sector remained fairly constant with no discernable trend. But ever since Virginia joined RGGI, there has been a clear shift. Since the beginning of 2021, Virginia's power plant emissions have followed the same downward trajectory as other RGGI participants. Virginia's total CO2 emissions in 2021 were over 4M tons lower than in 2020 (28.6M tons v. 32.8M tons), and emissions during the first half of 2022 have been even lower than the same period in 2021 (12.1M tons v. 13.6M tons). While emissions totals can fluctuate, the pattern is obvious--a long period of stagnating emissions before Virginia joined RGGI, followed by a continual year-over-year decrease in emissions after it did so. Moreover, since RGGI is structured so that the number of available	

	carbon allowances decreases 3% year-over-year, there is every reason to expect that those trends will continue. All of this clearly indicates that RGGI helps drive emissions reductions in participating states and that Virginia's efforts to reduce emissions would be severely hampered if it left RGGI. Participation in RGGI provides substantial benefits to Virginians. It will help Virginia reduce a significant source of CO_2, help protect against the worst effects of climate change, and reduce the costs of responding to extreme weather and sea level rise. Reducing emissions also will result in better health for Virginians by reducing particulate matter and other air pollutants. RGGI auctions are bringing in hundreds of millions of dollars per year to the state, which is required to be used on weatherization, flood prevention, and other measures that directly improve the lives of Virginians. Carbon pollution poses a significant threat to Virginians' health, welfare and safety. According to the CDC, the burning of fossil fuels has resulted in negative impacts to air and water quality and been linked to increased incidence of asthma and cardiovascular disease. Climate change also is leading to improved survival rates for vectors like ticks and mosquitos, resulting in increased incidence of disease. Being part of RGGI will undoubtedly improve those health outcomes. One study estimated that in just the first six years of RGGI's existence, emissions reductions from the program resulted in at least $5.7B in health benefits, including avoidance of 39,000 lost work/school days, 8,200+ asthma attacks, and 300–830 excess deaths. A later study identified an additional $200+ million in children's health benefits from reduced particulate contamination.	

	The sales of allowances at RGGI auctions are also netting significant revenues for the state. To date, Virginia has participated in seven RGGI auctions and has sold all of the 40+ million allowances it has placed into those auctions, receiving approximately $452M from those sales. Virtually all of those revenues are being used to respond to critical needs for Virginians--helping low-income households to reduce energy bills and assisting localities across the state with planning for and preventing recurrent flooding. As required by the Act, 50% of the proceeds from the RGGI allowance sales are credited to an account administered by DHCD to support low-income energy efficiency programs, including programs for eligible housing developments. DHCD developed its HIEE program to distribute the proceeds to WDRP and ASNHP. The WDRP funds repairs that have caused homes or units to be deferred from WAP. It is entirely funded by Virginia's sale of allowances in the RGGI auctions. DHCD uses RGGI proceeds for the ASNHA program, which completes energy efficiency upgrades that would not have been feasible otherwise. Through two rounds of applications, DHCD has used over $29M in proceeds from Virginia's allowance sales to help fund 36 high-efficiency affordable housing projects, representing more than 2,200 affordable housing units. These projects are distributed across the state. The Act requires another 45% of RGGI revenues to be placed in the CFPF, administered by DCR to assist localities and their residents affected by recurrent flooding, sea level rise, and flooding from severe weather events. To date, DCR has awarded a total of $45.9M in grants across three rounds of grants to 76 different projects across Virginia.	

	Repealing the program and withdrawing from RGGI would deprive citizens of hundreds of millions of dollars annually toward addressing these important causes. In most cases, RGGI revenues are the sole funding sources for those programs, so they would cease to exist if Virginia no longer participates in RGGI auctions. Leaving RGGI would thus do a grave disservice to Virginians and cause substantial harm to those vulnerable communities.	
35. SELC	The NOIRA and EO-9 Report both incorrectly claim that RGGI is placing a substantial burden on Virginians because RGGI compliance costs are driving rising electricity costs in Virginia. As an initial matter, the board may not premise a repeal based on the fear that Virginia's participation in RGGI might cause electricity rates to rise. The General Assembly expressly authorized utilities to seek to recover RGGI compliance costs from customers through a rate adjustment clause, subject to SCC approval. The board simply has no authority to second-guess the General Assembly's decision or take oversight authority away from the SCC. But moreover, the entire repeal proposal rests upon a flawed premise. RGGI is not driving increases in electricity bills. As of October 26, 2022, there is no active SCC-approved rate adjustment clause for either Dominion or Appalachian Power RGGI compliance costs. In other words, if the administration's illegal repeal took effect immediately, customers would not save a single penny. Even if there were SCC-approved rate adjustment clauses for either utility to cover RGGI compliance costs, electricity prices began increasing long before Virginia's participation in RGGI. Since Virginia re-regulated its electric utilities in 2007, customers have seen significant increases in electricity rates--increases that far exceed RGGI compliance costs.	See the response to comment 6 for further discussion of the utility structure in Virginia.

	The SCC laid this fact out in a report issued in September 2022. SCC figures clearly show that, for both Dominion and Appalachian Power, almost the entire increase in electricity costs has come from rate adjustment clauses, which are SCC-approved requests by utilities to recover costs for specific projects or compliance costs. The report also clarifies that none of these rate adjustment clause-related cost increases are caused by RGGI. Even more recent rate increases are not due to RGGI. According to the same SCC report, factors contributing to increased utility costs include inflation, pandemic recovery, supply chain limitations, and high natural gas and other commodity prices, as well as geopolitical events. RGGI was not listed as a contributing factor. Fuel factor costs add over $35 a month to the average Dominion residential bill--about one-quarter of the total. That includes an approximately $15 monthly increase that Dominion recently applied for (and the SCC approved). Due specifically to increased fossil fuel costs—primarily natural gas and coal, costs which have nearly doubled year over year--Dominion had under-recovered fuel costs by $1B and sought approval to raise the fuel factor significantly to cover this significant shortfall. Notably, this shortfall is for a single year, but at Dominion's request, customers will pay it off over three years. Had Dominion opted to collect its under-recovery over a one-year period, as is typical, bills would have been raised by $24 per month. Moreover, Dominion may seek additional rate increases next year if fossil fuel costs remain high, which they are expected to do. This means customers may face additional bill increases due to fossil fuel costs, before they have even paid off the 1-year, $1B under-recovery. Numerous other rate adjustments are driving up	

	customer bills, most of which are also fossil fuel-related. Dominion customers pay over $17/month for riders specifically related to coal or gas facilities. At present, the sole RGGI-related rate adjustment has been zeroed out, but even if Dominion were to reinstate it, that amount ($2.39/month) would pale in comparison to the fossil fuel-related charges, which total well over $50/months. The same pattern holds true for customers of Appalachian Power. At present, they pay $23/month for fuel factor costs, though the utility has a pending request to raise that amount to over $40/month to address recent increases in fuel costs. If approved, that would mean that between a quarter and a third of Appalachian Power residential customer bills would be fossil fuel-related costs, not to mention another $5+/month for coal and gas-related operations. By contrast, there are no approved RGGI-related surcharges for Appalachian Power customers currently, and less than $4/month is attributable to clean energy or energy efficiency programs. As Appalachian Power itself acknowledges, the best way to reduce customers' bills is to increase use of renewable energy so there is less need for coal and natural gas to generate power. While an almost never-ending proliferation of rate adjustment clauses has undoubtedly driven customer electricity rates up in Virginia, RGGI is not the cause of that increase. The administration has it exactly backwards when it comes to RGGI. As explained previously, without RGGI, Virginia power plant owners failed to reduce emissions from 2010-2020. Had RGGI been in place in Virginia during this time, customers would have been far better protected from the recent rise in fossil fuel costs. Participating RGGI states, for example, saw their emissions drop	

	by 50% between 2009-2020, meaning existing RGGI states were far less reliant on fossil fuels prior to the recent rise in fossil fuel costs. RGGI is a tool that protects customers from a major driver of rising electricity costs--fossil fuel costs--yet the administration seeks to repeal it. Moreover, though electricity prices have increased, Virginia's average retail electricity prices remain below the national average, even since joining RGGI. The average retail price of electricity across all sectors in Virginia is consistently lower than the national average over the last five years. The NOIRA states that "Virginians pay on average $2,323 per year in non-transportation energy costs, which is higher than the national average of $1,850." The administration simply refers to the U.S. DOE for these numbers but does not examine or explain the reasons for this difference. Are Virginians using more electricity? Are homes less efficient? Do they rely on electric heat more than other states? Are retail gas prices higher in Virginia than other states? Without understanding the cause, the administration has no basis for its misguided solution. In fact, repealing RGGI will exacerbate this problem. Continuing participation in RGGI will help lower non-transportation costs in two ways: forcing utilities to reduce reliance on fossil fuels that are currently (and likely to continue) causing significant increases in customer electricity costs; and providing funding to improve home efficiency and lower electricity bills. Moreover, the NOIRA is simply wrong in stating that RGGI operates as a direct tax in which all RGGI compliance costs are passed through directly to consumers with no incentives for the utility to change. Rather, the law permits monopoly utilities to seek recovery of compliance costs, but the utility may recover only those costs the	

	SCC finds to be necessary to comply with the emissions reduction program, in accordance with the statutory standard Customers thus are charged only when the utility tries to recover the costs and the SCC finds the costs necessary. Notably, although Dominion has sought to recover such costs in the past, it recently withdrew that rate adjustment request and the SCC approved that recission, meaning that customers have not been paying any RGGI-related costs for the past several months, even though Dominion continues to participate in RGGI auctions. The data is clear. The real cause of rising electricity costs is not RGGI--utility bills are high due to fossil fuel costs and myriad anti-customer provisions in Virginia's utility code that predate RGGI. Put another way, leaving RGGI will not reduce electricity rates by a single penny. If the administration wants to work to rein in electricity prices, it should recognize that RGGI is a tool that can help protect customers from fossil fuel prices and instead focus efforts on ongoing bipartisan work to reform the ratemaking system. In the last several years and this year, many bills have been introduced that would advance fair energy utility rates and enhance the availability of customer refunds. If the administration wants to reduce Virginians' energy costs, it should focus on the fundamental problems with Virginia's utility regulation.	
36. International Emissions Trading Association (IETA)	In more than a decade of operation, RGGI has only seen one state (New Jersey) leave the first-ever U.S. GHG cap-and-trade system. This departure occurred in close coordination with RGGI Inc., and at the end of a compliance period. RGGI faced minimal impacts from the state's departure, as New Jersey compliance entities were required to meet their compliance obligations at the end of that final period (prior to exit), and most of their allowances were	The commenter is correct that lowering electric bills without creating major market disruptions is essential, which is why DEQ is proceeding along the full APA regulatory path. The strategic goal is to finalize the regulation and ensure that compliance entities meet their final compliance obligations, all to coincide when the current contract with RGGI Inc., expires, and at the close of the current compliance period, at the end of 2023. This glide path has been designed to provide a smooth transition with minimal disruption to current regulatory and

	retired and removed from the program. We urge DEQ to craft regulations that minimize harm to electricity consumers and limit legal challenges as the state opts to leave RGGI by the end of 2023. This approach would help to achieve Governor Youngkin's goal of lower resident's electricity bills without creating major market disruptions. There are estimated 24.4M allowances in circulation held by Virginia entities for their estimated compliance obligations for 2021 and through June 2022. These holdings represent more than $320M in value to the utilities that hold them. Any move by the state to leave the program should be done to ensure these allowances still retain value until the state exits the scheme. In addition, much of the costs of those allowances has already been recovered or will be recovered from ratepayers by utilities. A path that would unilaterally scrap compliance obligations over the existing three-year period would effectively be a financial windfall for utilities, with Virginia residents bearing the brunt of this approach. Put simply, a DEQ decision to remove RGGI obligations would adversely impact electricity consumers, which would conflict with EO-9. Moreover, a regulatory framework that would remove obligations would also be legally fraught as Virginia would have acquired revenue for carbon allowance auctions without requiring entities to prove compliance with the relevant CO_2 program. As a real-life example, the Ontario Premier took a similar approach by stripping CO_2 obligations as the Canadian province left the Western Climate Initiative in 2018. Ontario did not offer refunds for allowances held, and the collective decision resulted	planning processes, and is similar to the approach taken by New Jersey.

	in numerous legal challenges, many of which are still ongoing. IETA urges Virginia to select a path that assures consumers will experience the least impact while not imposing additional legal burdens on the state. Maintaining the RGGI program CO_2 obligations through 2023 before transitioning away from a regulated market will provide certainty to market participants and consumers in Virginia. This approach would be similar to how New Jersey exited the scheme in 2011.	
37. Dominion Energy	Dominion supports the intended action to repeal Virginia's CO_2 Budget Trading program. In 2018, Dominion submitted comments to DEQ expressing concern that linkage to RGGI would result in a financial burden to customers with no real mitigation of regional GHG emissions. The company's position is unchanged despite the fact that Virginia ultimately became a direct participant in RGGI. Indeed, publicly available data suggest that reductions in CO_2 emissions in Virginia attributable to RGGI participation most likely will be offset by emissions increases within PJM states which are not beholden to the RGGI construct. While the regional emissions benefits of RGGI are uncertain, the additional costs borne by Virginia electric customers are clear. Under applicable regulatory law, the costs of CO_2 allowance purchases are recoverable through utility customers' electric rates. The company filed its first petition for approval of Rider RGGI in November 2020, in anticipation of future compliance costs associated with approximately 19M CO_2 allowance purchases per year. While initial cost estimates relied upon an expected allowance price of $6.84/ton, actual costs have exceeded this projection and	Support for the proposal is appreciated. As discussed in the response to comments 4 and 6, emissions reductions may be occurring regardless of RGGI or not, yet the electric rate structure established by Virginia law does not enable utilities to defer passing RGGI costs onto customers.

	continue to climb. Even at this initial cost projection level, typical Dominion residential customers using 1,000 kWh per month experienced a bill increase of $2.39 beginning on January 1, 2022. The company withdrew Rider RGGI from customer bills effective July 1, 2022. Prior to this withdrawal, the company presented estimates placing CO_2 allowance prices about 65% higher than originally projected and estimating that typical residential customer bills could increase by an additional $1.98, for total of $4.37/month. Bill increases for commercial and industrial customers, as well as residential customers using more than 1,000 kWh/month, would be even higher. It is important to recognize that Dominion will not be relieved of its obligation to procure CO_2 allowances until Virginia officially withdraws from RGGI. RGGI compliance costs will continue to accrue in the interim, and subject to regulatory approval, be passed on to customers. Virginia's RPS program incentivizes utilities to invest in renewable energy to comply with binding targets for the percentage of their retail electricity sales which must be matched with RECs from qualifying resources. Compliance with the RPS entails costs from REC purchases and development of eligible energy resources. And to reiterate, RGGI compliance entails costs from CO_2 allowance purchases. Both the RPS program and RGGI participation thus result in costs borne by Virginia electric customers to achieve what is fundamentally the same objective - ongoing reductions in power sector CO_2 emissions. Judge Jagdmann of the SCC, concurring with the Commission's ruling in Case No. PUR-2020-00169, wrote that the proceeding had "raise[d] the question of the need for two separate and distinct	

	modes for achieving carbon reduction," and noted the "potential costly duplications" that could arise. She wrote that, in light of the RPS, "it remains unclear whether the significant cost required for participation in an additional cap-and-trade program – which is expected to cost customers billions of dollars – are necessary for [utility] ratepayers to bear in order to achieve the General Assembly's carbon reduction objectives." Dominion is keenly aware of the need to maintain affordable electric rates and has a long record of rates below the national average as well as best in the business energy assistance programs, most notably our Energy Share Program. Since Virginia's Reregulation Act took full effect in 2008, Dominion's electric rates have remained consistently below the national average and have been very competitive among states in the DC metro area, the mid-Atlantic, and the southeast. We have also had rates well below the RGGI states' average. That said, amid economy-wide inflation and rising fuel costs, it is important to eliminate duplicative regulatory costs. Elimination of the additional RGGI compliance costs would further increase the competitiveness of the company's rates. Dominion is pursuing many projects that directly support the goal of reducing power sector CO_2 emissions and would be pursued irrespective of Virginia's status as a RGGI participant. These include solar and energy storage deployment, distribution grid transformation, RPS compliance, the Coastal Virginia Offshore Wind commercial project, energy efficiency programs, and license extensions for the company's zero-carbon nuclear units. Virginia has made steady progress toward carbon reductions in recent years, and existing statutory provisions will ensure that	

	emissions from the electric sector continue to decline regardless of whether Virginia continues participating in RGGI. RGGI does not further this goal but instead imparts unnecessary additional costs on Virginia customers with no evidence of incremental benefits.	
38. Environmental Defense Fund (EDF)	§ 10.1-1330 requires the executive branch and agencies to implement the state's RGGI regulation. Indeed, the General Assembly ratified the RGGI regulation, with certain specified changes, when it enacted the Virginia Clean Energy and Community Flood Preparedness Act in 2020, § 10.1-1330(A). The agencies could not at that time seek to rescind a regulation ratified by the legislature, and there is no basis in the statute for revisiting the legislature's decision. On the contrary, other provisions in this section confirm an ongoing obligation to carry out the RGGI regulation. Section 10.1-1330(B) authorizes the DEQ Director to "establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article" and then requires the Director to "seek to sell 100 percent of all allowances issued each year through the allowance auction." Thus, the statute requires the sale of allowances "each year," which assumes the state's ongoing participation in RGGI. The statute also requires allowance sale revenue to be used to fund specific programs such as flood prevention and low-income energy efficiency programs, § 10.1-1330(C). This allocation of funding further emphasizes that participation in RGGI is required because the legislature intended that auction revenue from participation in RGGI fund specific programs enumerated in the statute. Finally, § 10.1-1330(D) requires an annual report "describing the Commonwealth's participation in RGGI, the annual reduction in GHG emissions, the	The response to comment 9 addresses legal authority issues. See the response to comment 4 for a discussion of emissions reductions, and the response to comment 7 for a discussion of funding challenges and opportunities. Utility rates and structure are covered in the response to comment 6. Environmental justice issues are addressed in the response to comment 39..

	revenues collected and deposited in the interest-bearing account maintained by the Department pursuant to this article, and a description of each way in which money was expended during the fiscal year." If participation in RGGI were optional, this annual reporting requirement would be superfluous. Yet the General Assembly chose to include this reporting requirement, further indicating that Virginia's participation in RGGI is required by statute. Given the many ways the statute makes it clear that participation in RGGI is required by Virginia law, neither the board nor DEQ has the legal authority to end participation in RGGI. The agencies' authority and actions are bound by Virginia's statutory requirements--requirements that only both houses of the General Assembly and the Governor, acting in concert, may alter. RGGI has a long-proven record of emission reductions--a fact that DEQ acknowledged in its own report to the Governor. Continuing in this program would help Virginia achieve its stated goal of achieving a net-zero carbon economy by 2050. With unprecedented droughts, wildfires, floods and heat waves impacting communities nationwide, it's clear to Virginians that climate change is no longer a distant threat. The state has experienced eight different billion-dollar disaster events in 2021 alone. August 2022 was the hottest August recorded in North America and the second warmest August globally. These climate-powered disasters are a national security concern as well as an environmental one. The Hampton Roads area is home to dozens of military installations, including Naval Station Norfolk, the world's largest naval facility which supplies 46% of the regional economy. Funds brought in from RGGI auctions go towards bolstering Virginia's coastal resilience and	

	flood preparedness, ensuring military operations can continue to be run smoothly in the Hampton Roads region. Withdrawing from RGGI means removing the only source of funds for programs that help communities build resilience in the face of flooding and other climate threats. Only the General Assembly has the authority to cut off this vital funding source. Virginia is ranked 10th in the nation for clean energy employment with 88,370 jobs. Clean energy industries are poised for growth as Virginia continues to invest in its clean energy economy through RGGI. Analyses of the RGGI program have shown that growing jobs in the clean energy economy, reducing pollution, and investing in workers and local communities has substantial net benefits. One analysis found that over its first three compliance periods, RGGI created nearly 16,000 job-years in the region and in that same period added $1.4B of value to the economy. According to a new analysis of RGGI through 2017, the program has created over $4B in net economic gains and over 44,000 job-years of employment. Virginia has received approximately $452M in cumulative proceeds since its first auction in March 2021. Virginia Code mandates that 45% of those funds for their statewide Community Flood Preparedness Fund and 50% supports low-income energy efficiency programs. Program-wide, 18% of 2020 RGGI investments and 14% of cumulative RGGI investments went to clean and renewable energy projects across all participating states, which are expected to return over $600M in lifetime energy bill savings while also avoiding the release of over 1.7M short tons of CO_2. Direct bill assistance programs, also a priority investment area for RGGI, received 19% of 2020 RGGI investments and 16% of cumulative RGGI	

	investments, and have returned over $37M in credits or assistance to consumers. Investments from RGGI have saved money for participants on energy bills, while creating jobs and reducing carbon emissions. These investments are projected to save participants an estimated $2B over their lifetime on energy bills, while also avoiding the emission of 6.7M short tons of CO_2. Virginia also stands to receive investments from the passage of the Bipartisan Infrastructure Law, which allocated about $65M for weatherization and $5.5M to help prevent outages and make the power grid more resilient in Virginia. The Inflation Reduction Act helps consumers by making it more affordable for Virginia families to purchase energy efficient appliances, make repairs around their homes, and save money on their utility bills each month through new tax credits and rebates. RGGI's policies work in tandem with federal investment programs. Virginia will miss out on being a leader in the clean energy economy if it goes backward on state policy at the very moment that the federal government and businesses are injecting hundreds of billions into spurring the clean energy economy. Analysis from EDF also shows that federal programs will catalyze hundreds of billions of dollars in clean energy investment from the private sector. As of this summer, about 1 in 6 American households were behind on utility bills, as energy prices rose to the highest level in nearly 15 years. Gas provides about 37% of electricity in the US and the price of gas has tripled since the middle of last year. The U.S. Energy Information Administration also forecast in the September report that average residential electricity prices for this year would be 7.5% higher than in 2021, largely due to high natural gas prices.24	

	Virginians have the 10th highest average monthly residential electricity bills in the country. In 2022, Virginians paid on average $148.15 per month for residential electricity – $11 above the national average. In 2022, Virginia's electricity price was 13.53 cents/kWh compared to 12.02 in 2020. Renewables like solar panels can deliver power to 650 homes for one hour at $31-111 a megawatt-hour. By comparison, natural gas peaking plants deliver power at $122-162 a megawatt-hour. In Virginia in 2020, natural gas accounted for 61% of Virginia's utility-scale electricity net generation, nuclear supplied 29%, renewables, mostly biomass, provided 6%, and coal fueled less than 4%. There are many factors that contribute to the price of wholesale electricity, but the cost of fuel for fossil-fuel generators is an important driver. As noted by the EIA: "Wholesale prices are especially tied to natural gas prices because natural gas-fired units are often the most expensive (marginal) generators dispatched to supply power. The natural gas price at the Henry Hub averaged $8.14/MMBtu in May 2022, 180% higher year on year, according to the EIA, which expects the price of natural gas delivered to electric generators to average $8.81/MMBtu this most recent summer, a jump of 124% from summer 2021." Rising natural gas prices is one reason Dominion and Appalachian Power customers should expect a cost increase. In September 2022, the SCC approved the increase for Dominion, which went into effect provisionally on July 1. According to estimates, the average residential customer, defined as a household using 1,000 kWh of electricity per month, will see their monthly bill increase by $14.93. Dominion says this is due to the increase in its fuel factor. It is clear	

	that RGGI is not the driver of the rising electric prices we have seen in Virginia and elsewhere--rather, it is our current, fossil-fuel dependent system that is one of the major drivers. Cleaning up our grid by deploying generation that does not have volatile fuel prices, like wind and solar, is a critical part of the solution to clear our air, protect our climate, and benefit consumers. If the administration is concerned about customer costs, we recommend that it develop a comprehensive plan that achieves emission reductions to decarbonize the power sector and moves the state to cost-effective, clean energy. RGGI is the sole source of revenue for the statewide CFPF, which is the only state funding source for critical flood resilience planning and project implementation for localities, tribes, and soil and water conservation districts. RGGI has generated $203.5M for the CFPF since Virginia started receiving auction proceeds in 2021. Of this, nearly $46M has been awarded to more than 40 localities. The CFPF funds capacity-building initiatives that most federal grant programs do not, providing critical planning resources that allow localities to pursue larger project implementation requests. The CFPF can also be used as a local match for federal grant programs, making Virginia applicants more competitive for national programs. Without this reliable long-term funding source, localities will be unable to complete flood resilience planning they need to address flood risk. Twenty-five percent of CFPF monies are set aside for low-income geographies and the CFPF prioritizes implementation of nature-based solutions. Pulling Virginia out of RGGI would strip away funding that local governments need, harming under-resourced communities that do not	

	have the capacity to address flood risk on their own. Across the RGGI region, CO_2 emissions have dropped dramatically, thanks to fuel switching, improved energy efficiency, and growing renewable energy output. A report from The Acadia Center says emissions from the plants covered by RGGI are down 47% since 2009, when the program launched--outpacing the rest of the nation by 90%. Even while cutting emissions, the gross domestic product of RGGI states still grew by 47%, faster than the rest of the country, which grew by 31%. In Virginia, the data is clear that RGGI reduces emissions: RGGI cut Virginia power-plant carbon emissions by 13% in its first year. In 2020, carbon emissions in RGGI-covered units reached 32,755,842 short tons of CO_2 and declined to 28,623,530 short tons of CO_2 in 2021 even while demand increased. As carbon pollution from power plants decreases, Virginia is seeing co-benefits from the reduction of co-pollutant emissions like NOx and SO_2: in-state SO_2 emissions fell by 13% and in-state NOx emissions fell by 19% between 2020 and 2021. The Youngkin administration has even admitted the importance of RGGI in a recent report, concluding that RGGI "has a long track record of emission reductions since the beginning of the program." Participation in a carbon market with an overall cap on emissions, like RGGI, provides a high degree of certainty and durability that emissions reductions will be achieved year-over-year. As stated by DEQ, "an emission reduction program or combination of programs will be required to meet the Commonwealth's climate goals of the [VCEA] and the 2045 net-zero carbon emissions goal. In the absence of any such program,	

	emissions may not reduce sufficiently to achieve these goals." Since the beginning of the program through 2020, RGGI has avoided more than 49.5M short tons of carbon emissions in participating states. By remaining in RGGI, Virginia will be able to reduce overall emissions by an additional 30% from 2020-2030. Participating in RGGI means that Virginia can achieve its clean energy economy set forth in the VCEA, which requires that Virginia transition its utilities to renewable energy by 2050. Participation in RGGI gives Virginia the greatest certainty that the state will reach its emission reduction goals. A declining limit on GHG emissions, alongside other essential emission reduction regulations, provide the most reliable pathway for Virginia to meet its goal of net-zero emissions by 2045. Meeting this target is essential for Virginia to avoid the worst impacts of climate change, such as coastal flooding, displacement of up to 400,000 homes due to sea level rise, and billions of dollars to repair and replace homes and roads. Virginia currently has 10 cities and counties not meeting national health-based standards for ground-level ozone, impacting 2.3M Virginians. When carbon pollution is reduced, there are often significant reductions of other health-harming pollution, including ground-level ozone and soot. Power plants, transportation, industrial, and other sources contribute to emissions that impact air quality. According to EPA data, the power plants in Virginia covered by RGGI were responsible for 1,228 short tons of SO_X and 6,125 short tons of NOx pollution in 2021. As RGGI reduces carbon pollution across the region, communities will also benefit from declining levels of soot and smog. DEQ's analysis of the final RGGI	

	rule showed reductions of NOx, SO_2, and $PM_{2.5}$, amounting to tens of millions in monetized benefits over the life of the program. A study found that reduced levels of soot pollution due to RGGI from 2009-2014 benefited children's health, including avoiding cases of asthma, preterm births, cases of autism spectrum disorder and more harmful health impacts. The avoided costs of these health impacts on children are estimated at $191-350M. The Administration should consider the environmental justice impacts of its plan to roll back RGGI and the emission reductions that would be lost as a result. As previously noted by DEQ: "[n]ew laws passed by the General Assembly and signed by the Governor established that it is the policy of the Commonwealth to advance environmental justice. Further, DEQ's statement of policy (§10.1-1183, Code of Virginia) was amended to make environmental justice an explicit part of DEQ's mission." Virginians, like others across the country, are increasingly concerned about climate change and expect their leaders to act. A 2022 poll from Christopher Newport University showed that about 67% of Virginia voters want to stay in the RGGI program. Virginia joined RGGI after a lengthy round of public comment periods and public meetings where hundreds of concerned Virginians showed their support for reducing carbon emissions. Once the public comment period ended, the Virginia General Assembly held a vote that catalyzed RGGI into law. The State Senate voted 22-18 and the House of Delegates voted 51-47 to successfully pass the legislation. Recently, 61 state legislators, more than a third of the General Assembly, signed onto a letter addressed to the Board opposing	

	Gov. Glenn Youngkin's proposed withdrawal of Virginia from RGGI.	
39. New Virginia Majority	In our effort to secure environmental justice for people-of-color, immigrant communities, working-class families, women, and all Virginians alike, we focus our environmental policy efforts on state-level initiatives that shift Virginia toward an equitable 100% clean and renewable energy plan, a just transition, and targeted support for low-income individuals and people of color to obtain credentials, post-secondary education, or workforce training in environmental, renewable energy, or related fields. Therefore, we oppose this regressive proposed action to repeal Virginia's participation in RGGI even though this participation is mandated by state law. We support the continued implementation of RGGI as an important piece of state environmental and climate law. An effective state-level policy response to the climate crises requires rapidly eliminating GHGs from the electricity sector. Alongside recent federal climate mitigation investments in both the Infrastructure Investment and Jobs Act and the Inflation Reduction Act, RGGI enables Virginia to effectively decrease the state's dependence on fossil fuel generation and meet goals set in the state Clean Energy Policy. In addition to supporting mitigation of adverse climate change impacts statewide and regionally, RGGI supports reduction in public health and environmental justice outcomes associated with the pollution from fossil fuel generation facilities, particularly respiratory and cardiovascular diseases. Increasing investments in energy efficiency through RGGI is also fiscally responsible given that investment in energy efficiency is one of the most affordable policy strategies for decreasing GHGs from the electricity sector and	We appreciate the commenter's concerns, and agree that effective state level policy is needed to address carbon pollution in a fiscally responsible and equitable manner. . Indeed, it is people-of-color, immigrant communities, working-class families, women, and all Virginians alike who are disproportionately affected by unnecessary increases in electricity costs. The lack of transparency in the RGGI process, and the limitations on protecting public health and welfare from the effects of climate change forced on Virginia by that process impedes Virginia's ability to best serve all of its citizens.

	generating energy savings for residential customers. Beyond crucial executive orders and budgetary requirements passed to date, the U.S. still lacks codified federal law that outlines explicit clean energy standards or stands up nationally binding clean electricity targets. Virginia's participation in RGGI provides a climate policy that can help zero-out the state's electricity GHGs from public utility service providers fossil fuel powered plants. Household energy bills continue to rise, especially as a result of the increasing costs of non-renewable energy sources, specifically natural gas. This rise is predicted to increase beyond 2022. RGGI supports the growth of increasingly affordable renewable energy resources, which can help decrease the costs of household electricity, most burdensome to households with incomes at or below 50-100% of the Federal Poverty Level. Additionally, advancing legislative utility regulatory reforms that have been introduced to-date as opposed to repealing RGGI is the most effective approach to reducing energy costs concerns outlined in the NOIRA as the premise for repeal. These reforms include retiring cost recovery mechanisms that are uneconomical for customers, removing unnecessary restrictions on the issuance of customer refunds, and restoring the SCC's authority to adjust electricity rates when utilities earn above their authorized profits.	
40. Virginia Manufacturers Association (VMA)	Regulations should maintain an appropriate balance between environmental protection and economic development, be based on exemplary science, consider cost-benefit analysis and comparative risk assessments in the regulatory process, and allow for flexible and performance-based approaches. Energy policies should ensure sustainable economic	Support for the proposal is appreciated. As discussed elsewhere, participation in RGGI is not the most effective means of controlling carbon pollution, nor is it the most consumer-friendly approach.

	growth in manufacturing, with an emphasis on reliable supply at affordable prices. Tax policies should lower the overall effective tax rate on manufacturers. RGGI does not meet any of these public policy tests. VMA ardently supports this rulemaking to repeal RGGI. RGGI levies a direct, unnecessary tax on all Virginians. RGGI membership comes at a high cost and an uncertain benefit. Utilities must purchase an allowance for each ton of carbon emitted. The SCC has approved the pass-through of the allowance costs directly to residential and commercial ratepayers. Customers have no opt-out opportunity. As a result, all Virginians that use electricity must bear the cost of the RGGI program, which is substantial. EO-9 estimates that ratepayers must pay between $1-1.2B over the next four years. Our membership shoulders a substantial proportion of RGGI costs due to the commercial rate structure and electricity requirements to run a manufacturing facility. These facilities are the backbone of Virginia's economy, providing the jobs that fuel the state's economy. Virginia is highly ranked as a competitive southern state for manufacturing. RGGI participation jeopardizes this position. Increased energy costs inflate Virginia manufacturers' cost of operation, a burden not shared by most of the states with which Virginia manufacturers compete. When compared to non-RGGI states, Virginia's competitive advantage is threatened. Cost and regulatory burden is a constant consideration, as we compete for new businesses and existing manufacturers decide whether to stay. RGGI is an unnecessary, duplicative regulatory program in Virginia. Virginia is strongly committed to expanding the role of	

	renewable energy in power generation. Virginia's electric utilities are moving rapidly to expand generation from renewable resources. Virginia is already among the nation's leading states in this effort. Manufacturers have and are expected to continue to explore innovative ways to reduce carbon footprints. In fact, the VCEA establishes the state's climate goals. The VCEA is a comprehensive law to directly address the state's energy policies and to legislate change. The VCEA sets a 2045 net zero carbon emissions goal for the state's economy. To achieve this goal, the VCEA requires fossil fuel electric generating unit shutdowns and adds incentives for renewable generation. The VCEA also establishes an energy efficiency standard to achieve energy efficiency savings annually. The Act requires utility participation in a RPS program with annual goals for sale of renewable energy. DOE projects that Virginia is on schedule to meet the 2045 net-zero goal. RGGI is an ineffective solution to climate goals. In comparison to the VCEA, RGGI does not mandate or even incentivize utilities to make generation changes. RGGI does not cap utility emissions with a state budget. It does have a RGGI cumulative regional cap for all RGGI allowances, which is the only true cap in the program. As a result, the Virginia RGGI budget does not operate as a not-to-exceed cap to curtail emissions. This costly pass-through revenue program is unnecessary to promote the continued growth of renewable energy generation in the state. Virginia does not need RGGI to invest in strategic energy policies, infrastructure, and resilience programs. Virginia has and continues to effectively develop and implement direct, cost-effective programs to address the reported effects of climate change in	

	Virginia. RGGI, Inc. promotes the reinvestment of auction revenue in state programs addressing resiliency, energy efficiency, low-income communities, and other beneficial interests. However, the dollars that Virginia's citizens and businesses spend on RGGI would be much better spent directly on resiliency programs and initiatives with a tangible impact on communities. VMA supports legislative efforts to address these needs outside of the RGGI construct. A direct funding program is greatly preferable to RGGI. The CFPA directs most of the RGGI auction proceeds to assist with flooding from severe weather events and energy efficiency programs. However, using the RGGI platform comes at a cost. Fees are higher with no benefit to Virginians. RGGI, Inc., charges a fee to administer the program, and DEQ collects an additional charge to cover the program expenses and administrative costs. Virginia's utilities also must employ environmental professionals to undertake detailed, comprehensive compliance efforts required for RGGI participation. Aside from costs, Virginia loses control over its own money. RGGI states conduct a RGGI program review every 3-4 years, which results in revisions to the RGGI model rule that sets the program rules. That review can substantially impact the allowance costs of the program, not to mention the fundamental rules of participation. Virginia has only one vote among the RGGI states in this review process. In addition, on an implementation level, outside influences affect the costs of RGGI to Virginians. RGGI allowance costs are often driven higher by private market brokers and entities that purchase allowances to sell, often at a profit, or retire them. For example, in 2021, Virginia received $227M in	

	revenue from RGGI. However, only a little over $129M of that total was attributed to compliance entities, such as Dominion or other utilities, that purchased the allowances for compliance. The 2021 RGGI compliance year illustrates the influence of third-party entities on the RGGI program and how third-party stakeholders increase the amount of the direct tax that Virginians pay for RGGI. In summary, exiting RGGI will restore the state's independence. Virginia will be able to deliberately target resiliency and energy policy goals and address them without administrative fees, outside influences and with certainty. Virginia's carbon emissions are already rapidly dropping, without regard to RGGI. There are many reasons for this trend. First, conversion and retirement of coal-fired generation to natural gas and renewable generation has directly impacted Virginia's carbon footprint. DEQ documented the energy transition that took hold in 2011-2012 with a series of coal-fired plant retirements and fuel conversions. These power sector changes contributed to declining carbon emissions at a CO_2 emissions rate of 43% lower per unit of electricity between 2010-2020. This decline is faster than the nation as a whole and comparable to the RGGI states. These statistics illustrate that carbon emissions can be addressed without a costly regional carbon trading program. Citizens and businesses are becoming more energy efficient. Virginia is already among the nation's leaders in reducing CO_2 emissions. This trend began prior to RGGI membership. These data suggest that RGGI is not needed to achieve Virginia's climate goals. Carbon emissions are not a regional problem, they are a global problem. VMA has consistently articulated that regulating GHG	

	emissions on a regional basis does not make sense. CO_2 does not stop at the borders of RGGI states but coalesces in the atmosphere across states and internationally. Unlike CO_2 emissions, RGGI requirements are confined to state borders. Concepts such as leakage cut against a regional model. For example, a Regional Transmission Organization, such as PJM, may dispatch less expensive electric generating units with higher CO_2 emissions from a power generating plant located in a non-RGGI state in place of an electric generating unit with lower CO_2 emissions on the other side of the state border in a RGGI state. The result is that RGGI states may become net importers of electricity from lower cost non-RGGI assets. Recent data supports this result. Using EPA 2019 emissions data, three out of the five top states importing electricity from out of state were RGGI states (Maryland, Delaware, and Massachusetts). Delaware had the lowest statewide annual CO_2 emissions of any state in 2019, which was likely influenced by importing electricity into the state to satisfy customer demand. A regional approach is not the solution to a global problem, which is best left to a consistent federal approach. RGGI does not incentivize Virginia utilities to shift generation away from carbon-emitting assets, unlike other carbon reduction initiatives. In Virginia, customers bear increased costs associated with RGGI, rather than utilities. For example, the SCC approved that RGGI compliance costs would be passed through to customers in a RGGI Rider. The RGGI Rider appeared on residential and commercial bills as a direct cost. With customers paying the RGGI Rider, the RGGI program does not incentivize Virginia utilities to shift their generation mix away from fossil fuels. RGGI is better suited to other	

	RGGI states with more deregulated markets than in Virginia. In short, Virginia's energy market structure is not a conducive compliment to the RGGI regulatory approach.	

Public Participation

Indicate how the public should contact the agency to submit comments on this regulation, and whether a public hearing will be held, by completing the text below.

The board is providing an opportunity for comments on this regulatory proposal, including but not limited to (i) the costs and benefits of the regulatory proposal, (ii) any alternative approaches, (iii) the potential impacts of the regulation, and (iv) the agency's regulatory flexibility analysis stated in that section of this background document.

Anyone wishing to submit written comments for the public comment file may do so through the Public Comment Forums feature of the Virginia Regulatory Town Hall web site at: https://townhall.virginia.gov. Comments may also be submitted by mail, email or fax to Karen G. Sabasteanski, Department of Environmental Quality, P.O. Box 1105, Richmond VA 23218, phone 804-659-1973, fax 804-659-4178, email karen.sabasteanski@deq.virginia.gov. In order to be considered, comments must be received by 11:59 pm on the last day of the public comment period.

A public hearing will be held following the publication of this stage, and notice of the hearing will be posted on the Virginia Regulatory Town Hall website (https://townhall.virginia.gov) and on the Commonwealth Calendar website (https://commonwealthcalendar.virginia.gov/). Both oral and written comments may be submitted at that time.

Detail of Changes

List all regulatory changes and the consequences of the changes. Explain the new requirements and what they mean rather than merely quoting the text of the regulation. For example, describe the intent of the language and the expected impact. Describe the difference between existing requirement(s) and/or agency practice(s) and what is being proposed in this regulatory change. Use all tables that apply, but delete inapplicable tables.

If an existing VAC Chapter(s) is being amended or repealed, use Table 1 to describe the changes between the existing VAC Chapter(s) and the proposed regulation. If the existing VAC Chapter(s) or sections are being repealed and replaced, ensure Table 1 clearly shows both the current number and the new number for each repealed section and the replacement section.

Table 1: Changes to Existing VAC Chapter(s)

Current chapter-section number	New chapter-section number, if applicable	Current requirements in VAC	Change, intent, rationale, and likely impact of new requirements
9VAC5-140-6010	N/A	Purpose of the regulation is described.	Repealed in accordance with the directives of EO-9.

9VAC5-140-6020	N/A	Terms defined.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6030	N/A	Measurements, abbreviations, and acronyms used in the regulation are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6040	N/A	Entities to which the regulation applies are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6050	N/A	Standard requirements for permitting, monitoring, recordkeeping, liability, etc., are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6060	N/A	Computation of time is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6070	N/A	Severability is established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6080	N/A	Authorization and responsibilities of the CO_2 authorized account representative are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6090	N/A	The role of the CO_2 authorized alternate account representative is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6100	N/A	Changing the CO_2 authorized account representatives and the CO_2 authorized alternate account representative; changes in the owners and operators are delineated.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6110	N/A	The elements of an account certificate of representation are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6120	N/A	Objections concerning the CO_2 authorized account representative are addressed.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6130	N/A	Delegation by CO_2 authorized account representatives and CO_2 authorized alternate account representatives is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6140	N/A	CO_2 budget permit requirements are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6150	N/A	Submission of CO_2 budget permit applications.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6160	N/A	Information requirements for CO_2 budget permit applications are established.	Repealed in accordance with the directives of EO-9.

9VAC5-140-6170	N/A	Compliance certification reports are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6180	N/A	Actions on compliance certifications are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6190	N/A	The Virginia CO_2 Budget Trading Program base budgets are listed.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6200	N/A	How to handle undistributed and unsold CO_2 allowances is found in this section.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6210	N/A	Allowance allocations are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6220	N/A	CO_2 allowance tracking system accounts are established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6230	N/A	Establishment of accounts is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6240	N/A	The CO_2 allowance tracking system responsibilities of CO_2 authorized account representatives are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6250	N/A	How the recordation of allowance allocations is to be accomplished.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6260	N/A	Compliance requirements are established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6270	N/A	Banking requirements are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6280	N/A	Management of account errors is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6290	N/A	How to close general accounts.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6300	N/A	How to submit CO_2 allowance transfers.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6310	N/A	The recordation of allowance transfers is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6320	N/A	Notification of allowance transfers is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6325	N/A	Life-of-the-unit contractual arrangements are described.	Repealed in accordance with the directives of EO-9.

9VAC5-140-6330	N/A	General requirements for monitoring, reporting, and recordkeeping.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6340	N/A	The initial certification and recertification procedures for a monitoring system are delineated.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6350	N/A	Out-of-control periods are addressed.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6360	N/A	Notifications are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6370	N/A	Recordkeeping and reporting requirements are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6380	N/A	Petitions for approval to apply an alternative to any acid rain requirement are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6390	N/A	Reserved.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6400	N/A	Reserved.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6410	N/A	The purpose of the requirements for allowance auctions is provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6420	N/A	General requirements for the auction notice.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6430	N/A	[repealed section]	[already repealed]
9VAC5-140-6440	N/A	Program monitoring and review requirements.	Repealed in accordance with the directives of EO-9.
	*9VAC5-140-6445	Transition to repeal.	Affected facilities must place the allowances needed to meet their remaining compliance obligation into their compliance account in COATS as soon as practicable but no later than March 1, 2024, in order that they can be deducted from the account to meet the full control period obligation. This section will be repealed once all affected sources have met their full compliance obligation. Needed in order that the transition away from the program is conducted in such a way as to minimize disruption and enable affected facilities to meet their compliance obligations without introducing uncertainty to the market.

Attachment 18

https://richmond.com/news/state-and-regional/youngkin-i-have-the-power-to-pull-out-of-rggi/article_02aff6e8-bf4a-5925-ae4c-90d671e50dea.html

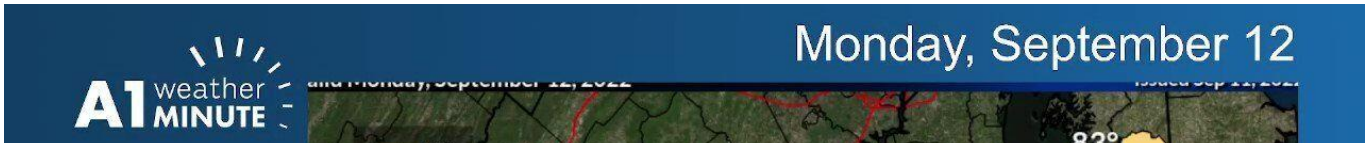
ALERT TOP STORY

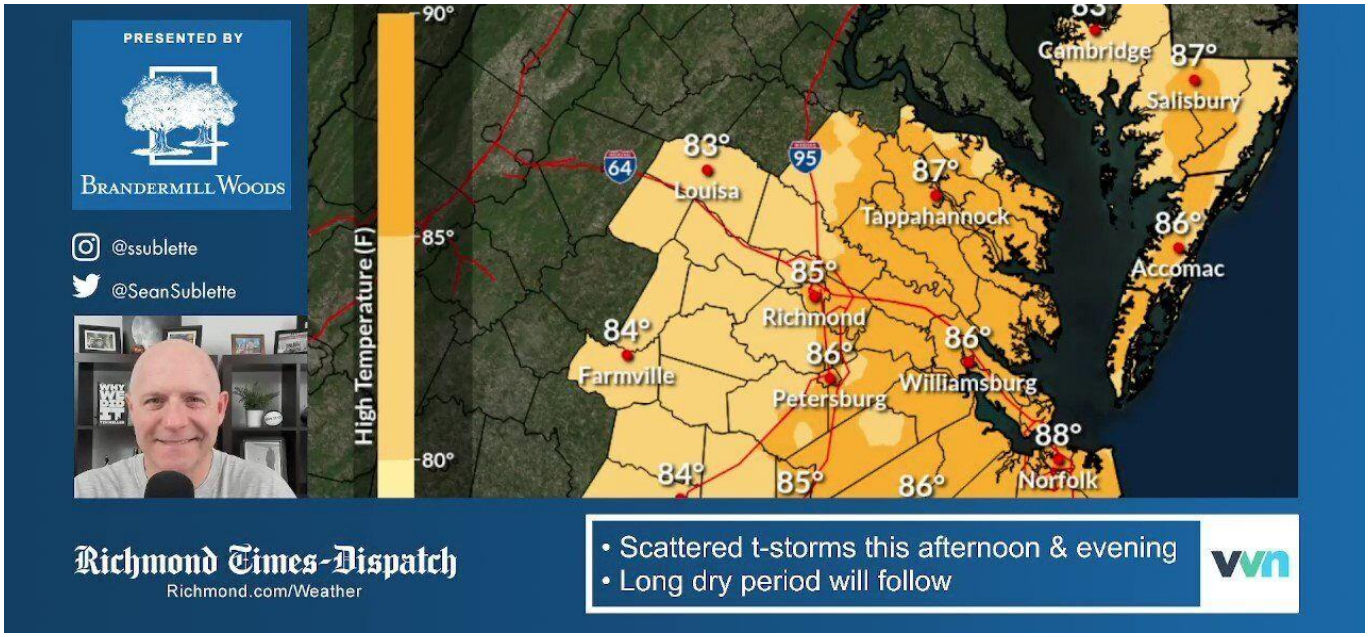
Youngkin: I have the power to pull out of RGGI

David Ress
Sep 12, 2022

In Stafford County, Gov. Glenn Youngkin ceremonially signed legislation to give military retirees a tax break. At right
PETER CIHELKA/THE FREE LANCE-STAR

David Ress





Tuesday through this coming weekend looks like a dry and more seasonable period.

For Gov. Glenn Youngkin, the problem with the **Regional Greenhouse Gas Initiative** is that it's a market that sends the wrong signals to the wrong people.

He wants out.

And so Youngkin and Democratic legislators, along with environmentalists across the state, are **drawing battle lines** over the 11-state carbon market, in which power companies can buy or sell carbon dioxide credits. They can be buyers, if their CO2 emissions exceed a cap, or sellers, if they want to get some extra money for emitting less of the greenhouse gas than their cap.

Many Democratic lawmakers say a state law calls for Virginia's participation in RGGI and that only the legislature can remove Virginia from the compact. Youngkin says that law allowed Virginia to join RGGI, but did not mandate Virginia's participation.

People are also reading...

1 **T.J. Maxx-brand 'Sierra' active & outdoor shop opening first Richmond store in Short Pump**

2 **As catalytic converter thefts rise in the Richmond area, local police promote new deterrence measure**

3 **High school 🏈 Week 9: Player of the week poll, local game stories and summaries, plus scores from around the state**

4 **Watch now: Police chief reacts to stabbing at Brookland Middle School**

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61 Dems say Virginia's participation in RGGI is up to legislature

The idea behind RGGI is that the price of those credits, along with the cost of buying allowances authorizing utilities to emit a limited amount of CO2, will affect decisions about using coal, oil and natural gas to spin the generators that make electricity — and emit CO2.

In the end, RGGI expects its market will move utilities toward generating power with sources that don't emit CO2.

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SENATE OF VIRGINIA

LYNWOOD W. LEWIS, JR.
6TH SENATORIAL DISTRICT
ALL OF ACCOMACK, NORTHAMPTON, AND MATHEWS COUNTIES; AND PART OF THE CITIES OF NORFOLK AND VIRGINIA BEACH

P. O. BOX 760
ACCOMAC, VIRGINIA 23301

COMMITTEE ASSIGNMENTS:
LOCAL GOVERNMENT, CHAIR
AGRICULTURE, CONSERVATION AND NATURAL RESOURCES
COMMERCE AND LABOR
EDUCATION AND HEALTH
RULES

September 8, 2022

Members of the Virginia Air Pollution Control Board
c/o Office of Regulatory Affairs
Department of Environmental Quality
P.O. Box 1105
Richmond, Virginia 23218

Sent via email: CitizenBoards@DEQ.Virginia.gov

Dear Members of the Air Pollution Control Board:

As current members of the Virginia General Assembly who voted for the Clean Energy and Community Flood Preparedness Act in 2020 or voted against changes to that same law in 2022, we write to express our continued support for Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI). Further, we write to articulate the reality that Virginia's participation in RGGI is mandated by *law*. Therefore, ultimately only a change in the *law* that passes both chambers of the General Assembly and is signed by the Governor can remove Virginia's participation. No proposed regulation, emergency regulation, regulatory act, or any subsequent administrative process can do so.

In addition to the Commonwealth's participation being mandated, RGGI is already delivering benefits to the residents of Virginia. As legislators, we believe it is important that you consider and understand the following benefits to Virginians from our participation in RGGI:

- RGGI has generated $378 million to support low-income energy efficiency programs and flood resilience infrastructure in Virginia.[1]
    - Energy efficiency upgrades are the best way to lower electricity bills, and Virginia's funds are directed to helping those households most in need.[2]
    - Flood resilience infrastructure protects Virginians against increased flooding and extreme weather events.
- RGGI has demonstrated Energy Cost Savings.
    - Electricity prices in RGGI states dropped by almost 6% while they went up by almost 9% throughout the rest of the country.[3] RGGI is a proven tool to reduce utilities'

[1] https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/Cumulative-State-Charts/VA_Proceeds_by_Auction.xlsx
[2] https://vaeec.org/rggi/
[3] https://acadiacenter.org/wp-content/uploads/2019/09/Acadia-Center_RGGI_10-Years-in-Review_2019-09-17.pdf

But Youngkin, whose time at the multi-billion-dollar Carlyle Group saw the firm move into carbon-reducing investments in a major way, doesn't buy that argument.

“Let’s not have a hidden tax … that was mis-sold and misrepresented as some sort of market-based incentive, because RGGI is not a market-based incentive,” Youngkin said in an interview with the Richmond Times-Dispatch.

Legislators mull ways to keep power bills down amid Regional Greenhouse Gas Initiative debate

“In this case, the utility can decide but they don’t have to worry about it because they can pass it right on to the consumer and the consumer Has. No. Choice,” he said.

“They have to buy power from the monopoly utility.”

That was shaping up to a fairly big bill.

The State Corporation Commission last year agreed with Dominion’s view that it would spend some $168 million to buy RGGI credits and that in order to cover that cost the bill for a typical residential customer using 1,000 kilowatt hours a month should rise by $2.39.

Youngkin seeks regulatory route to remove Virginia from RGGI

“We must recognize that utilities in this case are monopolies … were told they had to buy these allowances and all they do is 100 percent pass ’em on to the consumer, who has no say in this,” Youngkin said.

But Dominion this year asked, and the SCC agreed, to suspend the surcharge, noting that Virginia was on track to pull out of RGGI. Dominion said it could cover sums it had previously spent through base rates.

Youngkin said he won’t renew Virginia’s contract with RGGI when it expires in December 2023.

Meanwhile, he wants the state Air Pollution Control Board to repeal 2020 amendments to its C02 trading regulations requiring utilities to buy CO2 allowances — that is, RGGI authorization to emit a limited amount of the greenhouse gas.

Environmental group sues to get AG document on withdrawal from RGGI

The board can do that because it is part of the executive branch that the governor leads, he said.

General Assembly Democrats beg to differ. In a letter to the air board last week, 61 of them said the agency's powers are limited because the General Assembly created the air board.

"You only have the powers that the General Assembly grants you," the letter said.

The Democrats' letter also cites the law that enables participation in RGGI — the Clean Energy and Community Flood Preparedness Act — adding, "it is clear our intent for Virginia to participate in RGGI."

RGGI has generated $378 million to support low-income energy efficiency programs and flood protection in Virginia, the Democrats said.

Youngkin sees it differently:

"The bill that was passed … said that you could — it allowed you to go put this in place. It never mandated it," Youngkin said. "It allowed it, it never mandated it."

The bill says the director of the air board "is hereby authorized" to run the program to sell allowances that can be used in RGGI's trading system or something similar. It says the director "shall seek to sell 100 percent of all allowances" unless doing so would mean a net loss of benefit to consumers.

Youngkin said he reads that as allowing the air board to do away with the requirement that utilities buy the allowances, "and then we get to — as a government, the General Assembly — to work and if we want to provide funding for flood resiliency, then let's go provide funding for flood resiliency.

"Let's not have a hidden tax that was, that was mis-sold and misrepresented."

PAGES: Richmond Times-Dispatch coverage of Queen Elizabeth II in Virginia

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By David Ress

Attachment 19

COMMONWEALTH of VIRGINIA

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October 14, 2022

The Honorable Todd E. Pillion
Member, Senate of Virginia
851 French Moore Jr. Boulevard, Suite 178
Abingdon, Virginia 24210

Dear Senator Pillion:

I am responding to your request for an official advisory opinion in accordance with § 2.2-505 of the *Code of Virginia.*

Issue Presented

You inquire regarding the potential deployment of license plate recognition (LPR) cameras on Virginia Department of Transportation (VDOT) rights-of-way by third parties.[1] You specifically ask whether the Commonwealth Transportation Board (CTB) has the authority to amend its Land Use Permit Regulations (Regulations) to enable a permit to be issued for the installment of such cameras when requested by a law enforcement agency or local government. In particular, you seek guidance on whether the CTB can amend Part VII, Miscellaneous Provisions, of the Regulations to add the following language:

> **24 VAC 30-151-661. Stationary License Plate Readers.**
>
> Upon request of a locality or the chief law enforcement officer serving a locality, permits may be issued to a third-party provider to install a [LPR] within highway rights-of-way. Maintenance of these facilities is the responsibility of the permittee. Such permits may only be issued upon approval of the proposed operating agreement between the locality/law enforcement and the third-party provider which shall provide any pictures or data captured by such LPRs must be completely deleted within 30 days of capture.

[1] LPR technology is not specifically defined in your inquiry; for purposes of this opinion, an LPR camera is one that takes snapshots of passing vehicles, thereby obtaining and electronically caching information such as the vehicle make, type, and color, and the license plate number and state. This Office has described prior iterations of LPR technology as "a combination of cameras and optical character recognition technology to read license plates. The camera captures an image of a license plate and the optical character recognition technology converts the image into data that can be searched against an existing database or the data may be stored for future use, along with the time, date, and location of the observation." 2013 Op. Va. Att'y Gen. 7, 8-9. Although LPR technology may continue to evolve, salient here is that the LPR cameras collect snapshots of passing vehicles and store the images and related data for some period of time.

Applicable Law and Discussion

The Constitution of Virginia expressly provides that "administrative agencies may be created by the General Assembly with such authority and duties as the General Assembly may prescribe."[2] The General Assembly's delegation of its legislative power to administrative agencies "is essential to carry out the legitimate functions of government[: i]f nothing could be left to the judgment and discretion of administrative officers, government could not be efficient and the legislation itself would become 'either oppressive or inefficient.'"[3] Accordingly, administrative agencies may be empowered to make regulations, and validly adopted regulations carry the force of law.[4]

Unlike the General Assembly, which exercises plenary power limited only by the Virginia or United States Constitutions,[5] the agencies established by the General Assembly are creatures of statute and "derive[] [their] power only from [their] authorizing legislation."[6] An agency's authority to promulgate regulations therefore is not boundless; rather, the agency's power is limited to that which has been delegated by the General Assembly.[7] Absent such a delegation, an agency is precluded from acting in a legislative role.[8]

Central to your inquiry, therefore, is whether the General Assembly has delegated to the CTB the authority to promulgate regulations related to installing, for law enforcement purposes, LPR technologies operated by private parties at the request of a locality or law enforcement.

By statute, the General Assembly has empowered the CTB to "make regulations that are not in conflict with the laws of the Commonwealth for the protection of and covering traffic on and for the use of systems of state highways . . . ."[9] VDOT rights-of-way are part of the state highway system,[10] and pursuant to its statutory authority, the CTB has established a permitting system whereby parties may request certain

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[2] VA. CONST. art. III, § 1.

[3] Bell v. Dorey Elec. Co., 248 Va. 378, 379-80 (1994) (quoting Thompson v. Smith, 155 Va. 367, 379 (1930)).

[4] *See* VA. CODE ANN. § 2.2-4001 (2017); *see also* Manassas Autocars, Inc. v. Couch, 274 Va. 82, 87 (2007); 2014 Op. Va. Att'y Gen. 42, 45.

[5] Terry v. Mazur, 234 Va. 442, 449 (1987).

[6] Carpenter v. Virginia Real Est. Bd., 20 Va. App. 100, 106 (1995); *accord* Muse v. Virginia Alcohol Beverage Control Bd., 9 Va. App. 74, 78 (1989) ("The [Alcohol Beverage Control] Board, being a creature of statute, derives its powers from statute.").

[7] Sydnor Pump & Well Co. v. Taylor, 201 Va. 311, 316 (1959) ("[A]dministrative agencies, in the exercise of their powers, may validly act only within the authority conferred upon them by statutes vesting power in them.").

[8] The legislative power of the Commonwealth is vested in the General Assembly, VA. CONST. art. IV, § 1; apart from proper delegations of legislative authority to executive branch agencies, "[t]he legislative, executive, and judicial departments shall be separate and distinct, so that none exercise the powers properly belonging to the others, nor any person exercise the power of more than one of them at the same time . . . ." VA. CONST. art. III, § 1. *See generally* Elizabeth River Crossings OpCo, LLC v. Meeks, 286 Va. 287, 310-11 (2013); Cochran v. Fairfax Cnty. Bd. of Zoning Appeals, 267 Va. 756, 765 (2004) ("Under fundamental constitutional principles, . . . agencies are empowered to act only in accordance with standards prescribed by the legislative branch of government.").

[9] VA. CODE ANN. § 33.2-210(A) (2019).

[10] 24 VA. ADMIN. CODE § 30-21-10 (defining "right-of-way" generally to mean the "property within the system of state highways that is open or may be opened for public travel or use"); *accord* 24 VA. ADMIN. CODE § 30-151-10.

uses of the rights-of-way.[11] The current permitting Regulations "apply to all *authorized* use or occupancy of the right-of-way."[12] There is no statute expressly authorizing the general use of the equipment you present on VDOT rights-of-way. Nor is there explicit statutory authority permitting CTB to adopt regulations regarding the installation of data-gathering or surveillance equipment operated by private parties.[13]

Although the language authorizing the CTB to "make regulations . . . for the use of systems of state highways" may appear broad, such language must be considered in relation to the CTB's overall basic law.[14] The scope of an agency's regulatory authority is determined by taking into "account the text as well as the context of the underlying statute," whereby it is viewed it as a "symmetrical and coherent regulatory scheme."[15] The purposes underlying the basic law also are to be considered when examining the validity of agency action.[16]

As the Supreme Court of Virginia has noted, "[t]he General Assembly has delegated to the [CTB] . . . authority over the supervision, management, construction, improvement, and maintenance of public highways and roads."[17] A review of the statutes pertaining to the duties and powers of the CTB reveals that the CTB's basic law generally is limited to issues concerning the passage or conveyance on public roadways in the Commonwealth and enforcing traffic and safety requirements regarding the same.[18] The current Regulations related to rights-of-way generally reflect this understanding of the scope of CTB's

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[11] *See* 24 VA. ADMIN. CODE § 30-21-30(A) ("No person, firm, or corporation shall use or occupy the right of way of any highway for any purpose except travel, except as may be authorized by VDOT, either pursuant to regulation or as provided by law."); *see also* 24 VA. ADMIN. CODE § 30-21-20 (stating that "[n]o work of any nature shall be performed on any real property under the ownership, control, or jurisdiction of the [CTB] or VDOT, including . . . the right of way . . . in the system of state highways until written permission is first obtained from VDOT"); *accord* 24 VA. ADMIN. CODE § 30-151-20.

[12] 24 VA. ADMIN. CODE § 30-151-30(A) (emphasis added).

[13] Whether the installation of LPRs in the VDOT right-of-way by a third-party would be prohibited under the land use restrictions on vendors in the VDOT right-of-way is beyond the scope of this opinion. *See* 24 VA. ADMIN. CODE § 30-151-670(2).

[14] *See generally* VA. CODE ANN. § 2.2-4001 (defining "regulation" to mean "any statement of general application, having the force of law, . . . adopted by an agency in accordance with the authority conferred on it by applicable basic laws" and defining "basic law," in turn, as the "provisions of the Constitution and statutes of the Commonwealth authorizing an agency to make regulations or decide cases . . . .").

[15] Kavanaugh *ex rel.* Kavanaugh v. Virginia Birth-Related Neurological Inj. Comp. Program, 60 Va. App. 440, 447 (2012) (quoting Ragsdale v. Wolverine World Wide, Inc., 535 U.S. 81, 86 (2002)).

[16] Virginia Alcoholic Beverage Control Comm'n v. York St. Inn, Inc., 220 Va. 310, 313-14 (1979); Virginia Imps. Ltd. v. Kirin Brewery of Am., LLC, 41 Va. App. 806, 821 (2003); Johnston-Willis, Ltd. v. Kenley, 6 Va. App. 231, 244 (1988).

[17] Maddox *ex rel.* Maddox v. Commonwealth, 267 Va. 657, 662 (2004).

[18] *See, e.g.*, VA. CODE ANN. §§ 33.2-208 to -221.1 (2019 & Supp. 2022) (setting forth certain duties and powers of the CTB, to include designation of highway locations; responsibilities regarding certain transportation construction contracts; naming of highways, bridges, and other transportation facilities; prioritization of projects involving the funding of the state transportation system; regulation of roadside memorials; and setting fees for informational signs for motorists); §§ 33.2-300 to -414 (2019 & Supp. 2022) (providing for powers associated with establishing and maintaining highway systems, including road paving; designation of limited access highways, byways, and scenic highways); §§ 33.2-500 to -505 (2019) (relating to the designation and use of high-occupancy vehicle lanes); §§ 33.2-600 to -615 (2019 & Supp. 2022) (relating to ferries and toll facilities); s*ee also* VA. CODE ANN. §§ 46.2-808 (2017), -809 (2017), -809.1 (2017) (relating to the regulation of traffic on certain roadways); 46.2-931 (permitting regulation related to sales, solicitations, and distribution of materials within roadways and medians).

authority.[19] Indeed, in administering its statutory functions, the CTB itself has determined that "[t]he Code of Virginia authorizes the [CTB] . . . to promulgate regulations, establish guidelines, administer programs, or take other actions *related to transportation*."[20]

The camera installation you describe would not relate to the flow of traffic, the transportation network or assets, or uses of the state highways for travel. I find no nexus between the installation of LPR technology to aid law enforcement generally and the CTB's specific authority to issue regulations either "for the protection of," "covering traffic on," or "for the use of systems of state highways."[21] The proposed permitting of LPR cameras by the CTB for the benefit of third-party providers therefore falls outside the scope of authority currently delegated to the CTB.[22]

Not only does a review of the CTB's basic law, standing alone, fail to evince a legislative intent to authorize the CTB to regulate in this area, but an examination of other legislative action by the General Assembly further reveals that the CTB's authority to regulate is not so broad as to encompass the activity you present.[23] Other laws specifically address the use of cameras and similar equipment in connection with transportation assets in the Commonwealth. The General Assembly explicitly has authorized the use of "photo-monitoring systems," which take "photographs, . . . videotape, or other recorded images of [a] vehicle," to capture toll and traffic light violations.[24] The General Assembly also has authorized employing

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[19] *See, e.g.*, 24 VA. ADMIN. CODE § 30-151-470 (permits for bicycle and road races, parades and marches); 24 VA. ADMIN. CODE § 30-151-600 (permits for pedestrian and bicycle facilities); 24 VA. ADMIN. CODE § 30-151-630 (permits for school bus shelters, public transit shelters, or ride share stations); 24 VA. ADMIN. CODE § 30-151-610 (permits for the passage of oversized haulers and loaders); 24 VA. ADMIN. CODE § 30-151-460 (permits for moving buildings over 16 feet wide); 24 VA. ADMIN. CODE § 30-151-510 (permits for signals to facilitate the "safe and expeditious entry of emergency vehicles" onto the roadway); 24 VA. ADMIN. CODE § 30-151-530 (permits for flashing school speed limit signs). Other regulations concern land uses with direct or indirect impact to the roadways, including the physical integrity of roadways. *See, e.g.*, 24 VA. ADMIN. CODE §§ 30-151-300 to -430 (permits for utilities, including the placement of utilities under or over the pavement); 24 VA. ADMIN. CODE § 30-151-540 (permits for right-of-way grading).

[20] 24 VA. ADMIN. CODE § 30 (emphasis added). As a regulation interpreting the agency's governing statutes, this determination is entitled to great weight. *Manassas Autocars*, 274 Va. at 87.

[21] VA. CODE ANN. § 33.2-210(A).

[22] The maxim *noscitur a sociis*, which translates as "it is known from its associates," also applies here. It provides that "the meaning of a word takes color and expression from the purport of the entire phrase of which it is a part, and it must be read in harmony with its context." Turner v. Commonwealth, 226 Va. 456, 460 (1983). Accordingly, "[w]hen general words and specific words are grouped together, the general words are limited and qualified by the specific words and will be construed to embrace only objects similar in nature to those objects identified by the specific words." Cuccinelli v. Rector & Visitors of Univ. of Virginia, 283 Va. 420, 432 (2012) (quoting Andrews v. Ring, 266 Va. 311, 319 (2003)). The language of § 33.2-210 authorizing regulations "for the use of systems of state highways" thus must be read in light of the more limited language of the statute permitting regulations "protect[ing] or covering traffic." Such a reading conveys that activity that does not implicate travel and transportation uses is beyond CTB's powers.

[23] As "one body of law," the Virginia Code is to be viewed as a whole, and a statute should be interpreted so that it harmonizes with other statutes. 2004 Op. Va. Att'y Gen. 68, 70 (quoting Branch v. Commonwealth, 14 Va. App. 836, 839 (1992)).

[24] VA. CODE ANN. §§ 15.2-968.1(E) (2018); 46.2-819.1 (Supp. 2022); *see also* §§ 33.2-503(2)(a) (Supp. 2022) (providing for photo enforcement of HOT lanes) and 46.2-819.5 (Supp. 2022) (providing for use of a photo-monitoring system along the Dulles Access Highway).

"video-monitoring system[s]" to enforce traffic laws related to school bus safety[25] and "photo speed monitoring devices" to record speeding violations in highway work zones and school crossing zones.[26] By definition, these monitoring systems and devices are similar in function to LPR cameras. The statutes authorizing the use of this equipment are very detailed. That the General Assembly has set forth these uses with such particularity implies an intent that they not be done otherwise; *i.e.*, through an agency's regulatory action.[27] Accordingly, this express legislation governing, in particularized circumstances, the use of LPR-similar technology within the state highway system supports a finding that general authority to permit their use has not been delegated to the CTB and such authority remains solely vested in the General Assembly.[28]

In sum, I conclude that, although the CTB regulates many uses on VDOT rights-of-way, at present it may not use its regulatory power to permit the installation of LPR systems therein without a clear delegation of authority from the General Assembly. Regulations are designed "to provide for specific applications of the broader policy concerns addressed in legislation passed by the General Assembly."[29] To the extent that the CTB is to regulate such surveillance equipment, it must be with the express authority of the General Assembly.[30]

It is not lost on the Office of the Attorney General that the practical applications of LPR technology may be incredibly useful for law enforcement. It is clear that LPR technology has the potential to allow law enforcement agencies more rapidly to solve crimes; apprehend dangerous fugitives; recover stolen property; or locate missing persons, especially when used in conjunction with AMBER or Silver Alert. Nevertheless, equally evident is that approving and adopting a framework for using LPR technology remains squarely within the purview of the General Assembly, and neither this Office, nor an administrative agency may encroach upon the General Assembly's authority in the present matter.[31]

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[25] VA. CODE ANN. § 46.2-844 (Supp. 2022).

[26] Section 46.2-882.1 (Supp. 2022). *See* 2022 Op. Va. Att'y Gen. 22-014 (Aug. 15, 2022) (relating to VDOT permitting of such devices in light of express statutory authority providing for their use in particular circumstances), *available at* https://www.oag.state.va.us/files/Opinions/2022/22-014-Foster-issued.pdf.

[27] 2014 Op. Va. Att'y Gen. 34, 37, n.20; 1993 Op. Va. Att'y Gen. 59, 67 (citing Pine v. Commonwealth, 121 Va. 812, 821 (1917); 1991 Op. Va. Att'y Gen. 91, 93). Furthermore, the legislature is presumed to have intended each enactment to have a meaning that is consistent with other provisions of the law and that is not superfluous, but part of a harmonious and symmetrical whole. 2001 Op. Va. Att'y Gen. 192, 193 (citing Sch. Bd. v. Patterson, 111 Va. 482, 487-88 (1910)).

[28] Notably, these enactments themselves are limited to enforcing laws relating to traffic concerns and do not pertain to law enforcement generally. I further note that the General Assembly on many occasions has considered legislation concerning the use of LPR technology. *See, e.g.*, S.B. 1198 (2021 Reg. Sess.); H.B. 1657 (2017 Reg. Sess.); S.B. 236 (2017 Reg. Sess.); H.B. 141 (2016 Reg. Sess.); S.B. 236 (2016 Reg. Sess.); H.B. 1528 (2015 Reg. Sess.); H.B. 1673 (2015 Reg. Sess.); S.B. 965 (2015 Reg. Sess.); S.B. 452 (2014 Reg. Sess.). That the General Assembly often has taken up the issue of LPRs suggests that it believes this is an issue left to the legislature, and outside the purview of an administrative agency.

[29] 2014 Op. Va. Att'y Gen. at 43.

[30] *See* Portsmouth v. Va. Ry. & P. Co., 141 Va. 54, 68 (1925) ("It may be that in the evolution of transportation problems the time has come when the State should, for the public interest, empower the [State Corporation Commission] to relieve some of the street railway companies from some of their paving obligations, but for this relief the appeal must be made to the General Assembly. Neither the Commission nor the court has been vested with this sovereign legislative power, and cannot make but can only declare the law.").

[31] *See* Ours Props., Inc. v. Ley, 198 Va. 848, 851-52 (1957); Thompson v. Smith, 155 Va. 367, 381 (1930).

Conclusion

For the foregoing reasons, it is my opinion that the Commonwealth Transportation Board lacks the authority to amend its land use permit regulations to authorize a land use permit to be issued for license plate readers within the Commonwealth.

With regards, I am,

Very truly yours,

Jason S. Miyares
Attorney General

Attachment 20

COMMONWEALTH of VIRGINIA

Office of the Attorney General
Richmond 23219

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May 30, 2014

The Honorable L. Scott Lingamfelter
Member, House of Delegates
Post Office Box 7175
Woodbridge, Virginia 22195

The Honorable C. Todd Gilbert
Member, House of Delegates
Post Office Box 309
Woodstock, Virginia 22664

Dear Delegates Lingamfelter and Gilbert:

I am responding to your request for an official advisory Opinion in accordance with § 2.2-505 of the *Code of Virginia*.

Issues Presented

You ask whether the Governor of Virginia has authority to fail to implement or to follow a valid law that has been passed by the General Assembly and signed into law by the Governor in the absence of the General Assembly granting that authority either by statute or by the law's enactment clause. You also ask whether the President of the United States has authority not to implement the Affordable Care Act.

Response

It is my opinion that the Governor must enforce valid, duly enacted laws unless the power to delay or suspend enforcement is granted by statute[1] or by the law's enactment clause.[2] Based on longstanding precedent of this Office, I also conclude that a question related to the scope of power that can be exercised by the President of the United States with regard to enforcing a particular federal law is not an appropriate subject for an official Opinion of this Office.

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[1] One example of a statute granting modification and suspension authority is VA. CODE ANN. § 2.2-4014 (2011), which allows the relevant standing committees of the General Assembly, or the Joint Commission on Administrative Rules, which is created by VA. CODE ANN. § 30-73.1 (2011), to object to regulations or, with the concurrence of the Governor, to modify or suspend regulations.

[2] Herein, the phrase "duly enacted" means passed by the General Assembly and signed by the Governor, and it also means, in the case of a bill vetoed by the Governor, where the General Assembly has voted to override the veto pursuant to VA. CONST. art. V, § 6(b)(ii). This Opinion assumes that the laws at issue do not have any constitutional infirmity. If a constitutional infirmity in a particular law does exist, a separate legal analysis would be necessary. Such an analysis is beyond the scope of this Opinion.

Applicable Law and Discussion

I. General Duty Of Governor To Enforce Laws

Your first inquiry implicates several provisions of the Constitution of Virginia. First, Article IV, § 1 vests the legislative power of the Commonwealth in the General Assembly.[3] Article V, § 7 provides, in pertinent part, that "[t]he Governor shall take care that the laws be faithfully executed."[4] This provision is commonly known as the "take care" clause.[5] Our Constitution further expressly requires the separation of powers: Article I, § 5 provides that "the legislative, executive, and judicial departments of the Commonwealth should be separate and distinct . . .[,]" and Article III, § 1 provides that "[t]he legislative, executive, and judicial departments shall be separate and distinct, so that none exercise the powers properly belonging to the others, nor any person exercise the power of more than one of them at the same time . . . ."[6] Finally, Article I, § 7 expressly provides "[t]hat all power of suspending laws, or the execution of laws, by any authority, without consent of the representatives of the people, is injurious to their rights, and ought not to be exercised."[7]

A recent Opinion of this Office discusses the history and interplay of these constitutional provisions.[8] Although the Opinion dealt specifically with the application of these provisions to the Governor's power, through formal action, to suspend the enforcement of regulations having the force of law,[9] the reasoning of the Opinion applies equally to the failure of the Governor to enforce, implement, or follow duly enacted statutes. Indeed, as the Opinion explains, "[p]rohibiting the executive from suspending duly enacted laws has long been part of Virginia's constitutional history."[10]

Ignoring or failing to implement a duly adopted regulation or statute has the same practical effect as actively issuing a directive suspending the enforcement of such law. To conclude otherwise, in a fashion analogous to permitting the Governor to issue an order suspending or ignoring a regulation, "would render the 'take care' clause of the Virginia Constitution a mere nullity."[11] Further, in concluding

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[3] VA. CONST. art. IV, § 1.

[4] VA. CONST. art. V, § 7.

[5] Virginia's "take care" clause first appears explicitly in the Virginia Constitution of 1830. VA. CONST. of 1830 art. IV, § 4. It has appeared in every subsequent version of the Virginia Constitution. *See* VA. CONST. of 1851 art. V, § 5; VA. CONST. of 1864 art. V, § 5; VA. CONST. of 1870 art. IV, § 5; and VA. CONST. of 1902 § 73.

[6] VA. CONST. art. I, § 5 and art. III, § 1. The separation of powers is a bedrock principle of Virginia government. The concept of separation of powers in Virginia government first appears as § 5 of the Virginia Declaration of Rights of 1776. It has continued in every Virginia Constitution since then. *See* VA. CONST. of 1830 art. I, § 5 & art. II; VA. CONST. of 1851 art. I, § 5 & art. II; VA. CONST. of 1864 art. I, § 5 & art. II; VA. CONST. of 1870 art. I, § 7 & art. II; and VA. CONST. of 1902 §§ 5 & 39.

[7] VA. CONST. art. I, § 7. The explicit prohibition on suspending laws first appeared as § 7 of the Virginia Declaration of Rights of 1776. It has appeared in every subsequent version of the Virginia Constitution. *See* VA. CONST. of 1830 art. I, § 7; VA. CONST. of 1851 art. I, § 7; VA. CONST. of 1864 art. I, § 7; VA. CONST. of 1870 art. I, § 9; and VA. CONST. of 1902 § 7.

[8] *See* 2014 Op. Va. Att'y Gen. No. 13-109, *available via link at* http://www.ag.virginia.gov/Opinions%20and%20Legal%20Resources/Opinions/2014opns/Jan14opndx.html.

[9] The explicit question addressed in the prior Opinion was "whether the Governor has the power to issue a policy directive to suspend a regulation that was properly adopted pursuant to a statutory mandate." *Id.* at 1.

[10] *Id.* at 3.

[11] *Id.* at 4.

that the Governor may not unilaterally suspend a validly promulgated regulation, the previous Opinion noted that such action "is as much a violation of the separation of powers as if the Governor sought to suspend the operation of a Virginia statute,"[12] the action about which you inquire.

II. Duty Of President To Enforce Laws

Your second inquiry is whether the President of the United States may fail to implement or follow a specific law - the Affordable Care Act - that has been passed by Congress and that he has signed into law. Although this Office does from time to time interpret federal law, that is done in order to address the interplay between specific provisions of federal law and the laws of the Commonwealth. Such opinions, when rendered, help to inform state or local decisions. Questions related to the President's inherent, implied, or express authority are governed by a complex interplay of the United States Constitution and various federal laws, including federal legislative history, federal common law, and possibly opinions of the United States Attorney General and the Office of Legal Counsel. Finally, it is important to note a practical consideration: the President is not subject to or guided or governed by Opinions of this Office, and thus any Opinion our office might render on this subject would be merely academic. It would not have any practical impact on either the President's conduct or state or local decisions. In these circumstances, the question of the President's authority not to implement a particular law should be resolved by appropriate federal authorities, not by this Office. For those reasons, I respectfully decline to offer an Opinion of the Office on the matter.

Conclusion

Accordingly, it is my opinion that the Governor must enforce duly enacted valid laws, unless the power to delay or suspend enforcement is granted by statute or by the law's enactment clause. It is further my opinion that a question related to the President of the United States declining to implement a particular federal law is not an appropriate subject for an official Opinion of this Office.

With kindest regards, I am

Very truly yours,

Mark R. Herring

Mark R. Herring
Attorney General

[12] *Id.* at 5. The prior Opinion notes that there may be instances "where a statute . . . allows for [suspension] under certain circumstances, and thus, such suspension would not necessarily violate the separation of powers[,]" *id.* n.28; your request, however, expressly is limited to situations in which there is no statutory allowance.

Attachment 21

COMMONWEALTH of VIRGINIA

Office of the Attorney General

Kenneth T. Cuccinelli, II
Attorney General

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January 3, 2014

The Honorable Robert G. Marshall
Member, House of Delegates
Post Office Box 406
Richmond, Virginia 23218

Dear Delegate Marshall:

I am responding to your request for an official advisory opinion in accordance with § 2.2-505 of the *Code of Virginia*.

Issue Presented

You inquire whether the Governor has the power to issue a policy directive to suspend a regulation that was properly adopted pursuant to a statutory mandate.

Response

It is my opinion that, while the Governor has a significant role to play in the formulation of regulations promulgated by executive branch agencies, the Virginia Constitution prohibits the Governor from unilaterally suspending the operation of regulations that have the force of law.[1]

Background

The legislative power of the Commonwealth is and has been vested in the General Assembly.[2] Nevertheless, as the scope and reach of government increased, some thought it necessary to create administrative agencies (sometimes referred to as "executive branch agencies") to promulgate regulations to provide for specific applications of the broader policy concerns addressed in legislation passed by the General Assembly. The authority for the existence of such agencies is found in Article III, § 1 of the Virginia Constitution,[3] which provides in pertinent part that "administrative agencies may be created by the General Assembly with such authority and duties as the General Assembly may prescribe."

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[1] Your inquiry is stated in general terms; however, you then specifically reference a statement made by the Governor-elect, when he was a candidate, about regulations regarding the treatment of abortion facilities as hospitals. The same conclusion results regardless of the particular subject matter.

[2] VA. CONST. art. IV, § 1.

[3] Article III, § 1 also is one of the two provisions of the Virginia Constitution that mandates the separation of powers among the three branches of government. The dispensation for the creation of administrative agencies is the limited "exception to the basic principle" of separation of powers. 1 A.E. DICK HOWARD, COMMENTARIES ON THE CONSTITUTION OF VIRGINIA 433 (1974).

The grant of power to administrative agencies is limited. "[D]elegations of legislative power are valid only if they establish specific policies and fix definite standards to guide the official, agency, or board in the exercise of the power. Delegations of legislative power that lack such policies and standards are unconstitutional and void."[4] Furthermore, administrative agencies are often required to adopt regulations pursuant to the Virginia Administrative Process Act ("APA").[5] Pursuant to the APA, agency regulations are, prior to becoming effective, subject to public notice, and potentially, public hearings,[6] subject to public comment and, potentially, the taking of evidence,[7] subject to review by both the Attorney General and the Governor,[8] and subject to legislative review.[9] If an agency enacts a regulation consistent with its statutory charge[10] and that regulation has gone through the required regulatory processes for promulgation, it has the force of law.[11]

Applicable Law and Discussion

Before addressing the specific issue of whether the Governor has the authority to suspend a validly adopted regulation, it is important to recognize that the Governor has a significant ability to affect the issuance of regulations *prospectively*. As noted above, he has a statutory role in the adoption of regulations under the APA.[12] Additionally, the Governor affects the composition of administrative agencies through his appointments of the heads of administrative agencies[13] and their respective boards.[14] Furthermore, the Virginia Constitution explicitly authorizes the Governor to require certain officers and employees within state agencies to provide him with reports of the agency's activities and to allow him to inspect the agencies financial and other records.[15]

Another method governors have employed to influence the operations of state government is through the issuance of written directions. Whether called executive orders, executive directives, or guidance documents, these directions have been used by governors to have administrative agencies pursue the governor's policy objectives. Before turning to whether the Governor unilaterally may issue such directions to suspend a validly adopted regulation, it is helpful to review the Governor's general authority to issue such orders, directives, or guidance documents.

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[4] Bell v. Dorey Elec. Co., 248 Va. 378, 380, 448 S.E.2d 622, 623 (1994) (internal citation and quotation marks omitted).

[5] VA. CODE ANN. §§ 2.2-4000 through 2.2-4031 (2011 & Supp. 2013).

[6] Section 2.2-4007.01 (2011).

[7] Sections 2.2-4007 (2011); 2.2-4009 (Supp. 2013).

[8] Section 2.2-4013 (2011).

[9] Section 2.2-4014 (2011).

[10] Manassas Autocars, Inc. v. Couch, 274 Va. 82, 87, 645 S.E.2d 443, 446 (2007) (citations omitted) ("Regulations . . . may not conflict with the authorizing statute.").

[11] *Id.* at 445, 645 S.E.2d at 446 (citation omitted).

[12] Section 2.2-4013.

[13] VA. CONST. art. V, § 10 ("Except as may be otherwise provided in this Constitution, the Governor shall appoint each officer serving as the head of an administrative department or division of the executive branch of the government, subject to such confirmation as the General Assembly may prescribe. Each officer appointed by the Governor pursuant to this section shall have such professional qualifications as may be prescribed by law and shall serve at the pleasure of the Governor.").

[14] VA. CODE ANN. § 2.2-107 (2011).

[15] VA. CONST. art. V, § 8.

The Supreme Court of Virginia has noted that "[u]nder our system of government, the governor has and can rightly exercise no power except such as may be bestowed upon him by the constitution and the laws."[16] No provisions of the Constitution of Virginia or any statute explicitly grant to the Governor the authority to issue executive orders. Governors historically have issued executive orders based upon the authority inherent in the constitutional duty of the Governor to "take care that the laws be faithfully executed."[17] Prior opinions of the Attorney General recognize that the Constitution grants to the Governor a general reservoir of powers as chief executive of the Commonwealth.[18] Thus, the authority of the Governor to issue executive orders is well established in the law and history of the Commonwealth.

The scope of such authority, however, is limited. The Governor may not use an executive order (or any other means) to exercise legislative power, which is vested solely in the General Assembly.[19] Furthermore, the Governor may not issue executive orders or take other action that is contrary to express provisions of the Virginia Constitution.[20] Thus, if an executive order or other written direction amounts to an exercise of legislative power or violates a provision of the Virginia Constitution, the Governor is without power to issue it and the written direction necessarily is void.

Applying this legal background to your specific inquiry, it becomes clear that the Governor may not unilaterally (whether by executive order, executive directive or guidance opinion[21]) suspend the operation of a validly enacted regulation. As explained below, any attempt to do so would represent a violation of Article V, § 7, Article I, § 7, and the separation of powers provisions of the Virginia Constitution.

Prohibiting the executive from suspending duly enacted laws has long been part of Virginia's constitutional history. The drafters of both the Virginia Constitution and the United States Constitution were very familiar with claims that the executive had the authority to suspend or dispense with duly enacted laws, and both sets of framers sought to borrow from the English experience and prevent the executive from claiming such a power in the New World. As one scholar has noted regarding the drafting of the United States Constitution,

> In 1689, following the forced abdication of James II, Parliament enacted the English Bill of Rights. The first declaration of that momentous statute was "that the pretended Power of Suspending of Laws, or the Execution of Laws, by regal Authority, without Consent of Parliament, is illegal." The royal dispensing prerogative was also declared illegal.
>
> The English Bill of Rights became a template for American constitution drafting. Virtually every secular provision in that statute was incorporated into the U.S. Constitution. The prohibition on the suspending and dispensing powers was encoded in

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[16] Lewis v. Whittle, 77 Va. 415, 420 (1883).

[17] VA. CONST. art. V, § 7.

[18] *See* 1983-84 Op. Va. Att'y Gen. 180; 1945-46 Op. Va. Att'y Gen. 144.

[19] *See* VA. CONST. art. I, § 5; art. III, § 1; art. IV, § 1.

[20] *Lewis*, 77 Va. at 420.

[21] As they pertain to regulations, "guidance documents" are referenced in § 2.2-4008 of the *Code of Virginia*. Nothing in § 2.2-4008 would allow for a guidance document that was inconsistent with the regulation itself or the relevant authorizing statute. Rather, guidance documents, as properly understood, only may explain or amplify the relevant regulation or statute. Definitionally, suspending the operation of a regulation would neither explain nor amplify the regulation, but rather, only subvert it.

> Article II's requirement that the President must "take Care that the Laws be faithfully executed." Thus, these rejected royal prerogatives were denied to the President.[22]

The drafters of Virginia's Constitution adopted nearly identical language, seeking to effectuate the same prohibition.[23] Article V, § 7 of the Virginia Constitution provides, in pertinent part, that "[t]he Governor shall take care that the laws be faithfully executed."[24]

Validly implemented regulations carry the force of law;[25] thus, it should be self-evident that unilaterally issuing a directive that suspends or ignores such a regulation is inconsistent with the Governor's duty to "take care that the laws be faithfully executed." To conclude otherwise would grant the Governor a suspending power that has been denied to the English King since at least 1689 and would render the "take care" clause of the Virginia Constitution a mere nullity. Simply stated, the Virginia Constitution's "take care" clause prohibits the Governor from issuing instructions (whether by executive order, executive directive or guidance opinion) that a valid regulation be suspended or ignored.

While the framers of the federal constitution apparently believed that the federal "take care" clause was sufficient to make clear that the executive could not suspend validly enacted laws, Virginia went one step further. Article I, § 7 of the Virginia Constitution expressly provides "[t]hat all power of suspending laws, or the execution of laws, by any authority, without consent of the representatives of the people, is injurious to their rights, and ought not to be exercised."[26] Thus, the prohibition that is implicit in Article V, § 7's "take care" clause is made explicit by Article I, § 7: the Governor may not unilaterally direct, by any means, that a validly adopted regulation that has the force of law be suspended or ignored.

Irrespective of the prohibitions found in Article V, § 7 and Article I, § 7, the Virginia Constitution nonetheless would prohibit the Governor from unilaterally suspending a validly adopted regulation carrying the force of law. Specifically, such action would violate the separation of powers provisions found in Article I, § 5 ("That the legislative, executive, and judicial departments of the Commonwealth should be separate and distinct . . . . ") and Article III, § 1 ("The legislative, executive, and judicial

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[22] Robert J. Reinstein, *The Limits of Executive Power*, 59 AM. U. L. REV. 259, 280 (2009) (footnotes omitted).

[23] Whether the nation borrowed from Virginia or whether Virginia borrowed from the nation is unclear. Virginia's "take care" clause first appears explicitly in the Virginia Constitution of 1830. VA. CONST. of 1830 art. IV, § 4. At least one scholar has suggested that the federal "take care" clause "descends to us from the English Bill of Rights, via the Virginia Constitution, and was intended to forbid the executive's suspension of statutes." Peter M. Shane, *Restoring Faith in Government: Presidents and the Separation of Powers, Pardons, and Prosecutors: Legal Accountability*, 11 YALE L. & POL'Y REV. 361, 393-94 (1993) (footnote omitted).

[24] As noted in note 23 *supra*, this language first appeared in the Virginia Constitution of 1830. It has appeared in every subsequent version of the Virginia Constitution. *See* VA. CONST. of 1851 art. V, § 5; VA. CONST. of 1864 art. V, § 5; VA. CONST. of 1870 art. IV, § 5; and VA. CONST. of 1902 § 73.

[25] *See Manassas Autocars, Inc.*, 274 Va. at 87, 645 S.E.2d at 445. *See also* VA. CODE ANN. § 2.2-4001 (2011) (defining a "regulation" under the Administrative Process Act as "any statement of general application, having the force of law, affecting the rights or conduct of any person, adopted by an agency in accordance with the authority conferred on it by applicable basic laws.").

[26] The explicit prohibition on suspending laws first appeared as § 7 of the Virginia Declaration of Rights of 1776. It has appeared in every subsequent version of the Virginia Constitution. *See* VA. CONST. of 1830 art. I, § 7; VA. CONST. of 1851 art. I, § 7; VA. CONST. of 1864 art. I, § 7; VA. CONST. of 1870 art. I, § 9; and VA. CONST. of 1902 § 7.

departments shall be separate and distinct, so that none exercise the powers properly belonging to the others, nor any person exercise the power of more than one of them at the same time . . . .").[27]

It must be remembered that, when adopting a regulation, an administrative agency is not engaged in an executive function, but rather, it is exercising legislative authority that has been delegated to it by the General Assembly. As noted above, the authority for the existence of such agencies is found in Article III, § 1 of the Virginia Constitution, which provides in pertinent part that "administrative agencies may be created by the General Assembly with such authority and duties as the General Assembly may prescribe." Because administrative agencies are exercising delegated legislative authority, a unilateral attempt[28] by the Governor to suspend a validly enacted regulation is as much a violation of the separation of powers as if the Governor sought to suspend the operation of a Virginia statute. It is simply beyond a Governor's power to do so, and any such attempt is void.

This conclusion is consistent with the APA's provisions regarding withdrawal of regulations. Section 2.2-4016 provides that

> [n]othing in this chapter shall prevent any agency from withdrawing any regulation at any time prior to the effective date of that regulation. A regulation may be repealed after its effective date only in accordance with the provisions of this chapter that govern the adoption of regulations.

Thus, for regulations promulgated under the APA, it is clear that the executive branch (in this case the relevant agency itself) has the ability to dispense with a regulation at any time prior to its effective date; however, once it becomes effective, the executive no longer may dispense with the regulation unilaterally. Rather, the regulation can be changed or suspended only by going through the full APA process, as a result of a change in the authorizing statute being passed by the General Assembly and becoming law, or by order of a court of competent jurisdiction. Thus, a guidance opinion from the Governor is not legally sufficient to effectuate a change in or suspension of a validly enacted regulation.

Conclusion

Accordingly, it is my opinion that that, while a Governor has a significant role to play in the formulation of regulations promulgated by executive branch agencies, the Virginia Constitution prohibits a Governor from unilaterally suspending the operation of regulations that have the force of law.

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[27] The separation of powers is a bedrock principle of Virginia government. The concept of separation of powers in Virginia government first appears as § 5 of the Virginia Declaration of Rights of 1776. It has continued in every Virginia Constitution since then. *See* VA. CONST. of 1830 art. I, § 5 & art. II; VA. CONST. of 1851 art. I, § 5 & art. II; VA. CONST. of 1864 art. I, § 5 & art. II; VA. CONST. of 1870 art. I, § 7 & art. II; and VA. CONST. of 1902 §§ 5 & 39.

[28] It is conceivable that there could be circumstances where a statute or regulation allows for the regulation to be suspended under certain circumstances, and thus, such suspension would not necessarily violate the separation of powers. You do not inquire about such a scenario, and a review of all of the specific facts and circumstances would be necessary to determine if such a scenario violated some portion of the Virginia Constitution. Accordingly, such inquiry is beyond the scope of this opinion, and I do not address it in the abstract here.

With kindest regards, I am

Very truly yours,

Kenneth T. Cuccinelli, II
Attorney General

Attachment 22

Archived Content

Warning: Some referenced links may not function correctly.

For Immediate Release: April 12, 2020

Contacts: Office of the Governor: Alenaa Yarmosky, Alena.Yarmosky@governor.virginia.gov

Governor Northam Signs Clean Energy Legislation

RICHMOND—Governor Ralph Northam is accelerating Virginia's transition to clean energy by signing the Virginia Clean Economy Act and by amending the Clean Energy and Community Flood Preparedness Act that requires Virginia to join the Regional Greenhouse Gas Initiative.

"These new clean energy laws propel Virginia to leadership among the states in fighting climate change," **said Governor Northam**. "They advance environmental justice and help create clean energy jobs. In Virginia, we are proving that a clean environment and a strong economy go hand-in-hand."

The **Virginia Clean Economy Act** was passed as House Bill 1526 and Senate Bill 851, which were sponsored by Delegate Richard C. "Rip" Sullivan, Jr. and Senator Jennifer McClellan, respectively. The Act incorporates clean energy directions that the Governor issued in Executive Order Forty-Three in September 2019. It results from extensive stakeholder input and incorporates environmental justice concepts related to the Green New Deal.

The law requires new measures to promote energy efficiency, sets a schedule for closing old fossil fuel power plants, and requires electricity to come from 100 percent renewable sources such as solar or wind. Energy companies must pay penalties for not meeting their targets, and part of that revenue would fund job training and renewable energy programs in historically disadvantaged communities. The Act accomplishes the following broad goals:

- **Establishes renewable portfolio standards**. The Act requires Dominion Energy Virginia to be 100 percent carbon-free by 2045 and Appalachian Power to be 100 percent carbon-

free by 2050. It requires nearly all coal-fired plants to close by the end of 2024.

- **Establishes energy efficiency standards**. The Act declares energy efficiency pilot programs to be "in the public interest." It creates a new program to reduce the energy burden for low-income customers, and it requires the Department of Social Services and the Department of Housing and Community Development to convene stakeholders to develop recommendations to implement this program. The Act sets an energy efficiency resource standard, requiring third party review of whether energy companies meet savings goals.
- **Advances offshore wind**. The Act provides that 5,200 megawatts of offshore wind generation is "in the public interest." It requires Dominion Energy Virginia to prioritize hiring local workers from historically disadvantaged communities, to work with the Commonwealth to advance apprenticeship and job training, and to include an environmental and fisheries mitigation plan.
- **Advances solar and distributed generation**. The Act establishes that 16,100 megawatts of solar and onshore wind is "in the public interest." The law expands "net metering," making it easier for rooftop solar to advance across Virginia. The new law requires Virginia's largest energy companies to construct or acquire more than 3,100 megawatts of energy storage capacity.

"This is a terrific day for Virginia," **said Delegate Richard C. "Rip" Sullivan, Jr**. "While some said Virginia is moving too fast, we said this is the year to get it right. This is an historic step forward on clean energy in Virginia."

"This is the most significant clean energy law in Virginia's history," **said Senator Jennifer McClellan**. "The bill that the Governor signed will make Virginia the first southern state with a 100 percent clean energy standard. The Act will create thousands of clean energy jobs, make major progress on fighting climate change, and break Virginia's reliance on fossil fuels."

The Clean Energy and Community Flood Preparedness Act was passed as House Bill 981 and Senate Bill 1027, sponsored by House Majority Leader Charniele Herring and Senator Lynwood Lewis, respectively.

The Act establishes a carbon dioxide cap-and-trade program to reduce emissions from power plants, in compliance with the Regional Greenhouse Gas Initiative (RGGI). The Department of Environmental Quality will establish and operate an auction program to sell allowances into a market-based trading program.

The Act creates a Virginia Community Flood Preparedness Fund to enhance flood prevention, protection, and coastal resilience. It creates a low-interest loan program to help inland and coastal communities that are subject to recurrent flooding. The sale of emissions allowances would fund it.

The Governor proposed technical amendments to clarify how the fund would operate. The amendments provide for forgiveness of loans used in low-income geographic areas.

“By joining RGGI, Virginia will take part in a proven, market-based program for reducing carbon pollution in a manner that protects consumers,” **said Governor Northam**. “I am proposing important refinements and I look forward to signing it into law soon.”

“Advocates have worked hard for many years to put Virginia on the path to clean energy,” **said House Majority Leader Charniele Herring**. “This will bring cleaner air and water to Virginia, and the Governor’s amendments will make a good law even better.”

“Joining RGGI will secure a sustainable clean energy future for Virginia,” **said Senator Lynwood Lewis**. “Thanks to the Governor’s leadership, we’re almost at the finish line.”

Last year’s budget explicitly prevented Virginia from joining RGGI.

# # #

Attachment 23

ENERGY + ENVIRONMENT

COMMENTARY

Clean air and clean water are more important now than ever

GUEST COLUMN

APRIL 24, 2020 12:01 AM

The sun sets over the James River in Richmond. (Ned Oliver/Virginia Mercury)

By David K. Paylor

In the face of the greatest public health crisis in decades, we are more aware than ever of the connection between environmental protection, public and individual health and a strong economy. As we enter a new decade of environmentalism, it is worth reflecting on how far we have come so we can move forward with confidence and commitment to address new and urgent challenges.

This week, amid the COVID-19 pandemic, we celebrated the 50th anniversary of Earth Day. This movement started in 1970, when 20 million people gathered in the streets of America to encourage our leaders to rise to the challenge of protecting the environment. From the decimation of our bald eagle population from DDT use to contaminated rivers catching fire, the evidence was painfully clear that we were not adequately aware of our impact on the environment, and its importance to human health. Out of this new awareness, a movement was born.

The 1970s saw the passage of the most comprehensive environmental legislation in U.S. history, including the Clean Air Act, the Clean Water Act, the Endangered Species Act, the Toxic Substances Control Act and the Surface Mining Control and Reclamation Act. In addition, just months after the first Earth Day, a new federal organization tasked with monitoring the nation's natural assets – the Environmental Protection Agency – was created.

The Virginia Department of Environmental Quality is the environmental agency in the commonwealth, safeguarding the places we live and promoting the health and well-being of eight million people. The agency follows laws that provide us with the framework to keep air, water and land clean by preparing and issuing permits to businesses, local governments and state and federal facilities. These permits establish safe limits, reduce pollution and hold violators accountable.

Our efforts are paying off. For example, Virginia is breathing cleaner air than ever before. Water quality improvements have helped bring the Chesapeake Bay back to life. Thousands of acres of contaminated land are being cleaned up and recovered. We have worked with businesses and environmental partners to ensure that strong environmental protections and a strong economy can go hand in hand.

To carry out DEQ's extensive permitting programs and environmental protection and conservation initiatives, we collaborate with a statewide team of partners to help develop clean-up plans for waterbodies, work with dedicated volunteers to monitor recreational waters, oversee the revitalization of contaminated sites to turn distressed property into viable real estate, and respond to pollution complaints and environmental emergencies to assist first responders and mitigate destructive impacts.

This takes a talented team of professionals from six regional locations and the central office. We are engineers, biologists, hydrologists, geologists, meteorologists, inspectors, regulators, modelers, policy makers, permit writers, administrators, communicator and, of course, environmentalists. Most of all, we are mission-driven problem solvers.

The challenges ahead will require innovative approaches to environmental protection that extend into much more complex areas of public policy such as addressing climate change, environmental justice and sustainable economic development. As demonstrated by the COVID-19 pandemic, community health is a vital component of community resilience.

To that end, with direction and support from the governor's office and the secretary of natural resources, DEQ is invested in being part of the solution. We are currently engaged in a wholesale review of our environmental justice procedures, we are committed to transparency, public accessibility of our work and establishing programs to continue to effectively administer our environmental protection programs.

We are also committed to reducing the pollution that causes climate change. The governor has signed the Virginia Clean Economy Act and amended the Clean Energy and Community Flood Preparedness Act to require Virginia to join the Regional Greenhouse Gas Initiative (RGGI).

As the governor has said, by joining RGGI, Virginia will take part in a proven, market-based program for reducing carbon pollution in a manner that protects consumers.

On Earth Day – and every day – our number one priority remains to protect the commonwealth's diverse and abundant natural resources in everything we do. Through this important work, DEQ supports agriculture, industry and commerce, and provides a rich, healthy environment for plants, wildlife and people.

Together, we have made much progress in Virginia over the past few decades. We plan on continuing this legacy as we move forward to address the new challenges in the years ahead.

David K. Paylor is director of the Virginia Department of Environmental Quality.

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GUEST COLUMN

Views of guest columnists are their own. To submit an op-ed for consideration, contact Editor Sarah Vogelsong at svogelsong@virginiamercury.com.

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A NEW LOOK AT THE OLD DOMINION

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Attachment 24

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SERVICE FINDER (https://www.deq.virginia.gov/air/greenhouse-gases)

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Greenhouse Gases

Gases that trap heat in the atmosphere are called greenhouse gases (GHGs). These include carbon dioxide, methane, nitrous oxide and fluorinated gases. Solar radiation in the lower atmosphere acts like a “greenhouse” – thus the name – preventing heat from escaping. Emissions of greenhouse gases into the atmosphere is the main cause of climate change.

Virginia is committed to addressing the pollutants that contribute to climate change. The Virginia Clean Economy Act establishes renewable portfolio and energy efficiency standards, and advances offshore wind and solar generation, and the Clean Energy and Community Flood Preparedness Act requires Virginia to join the Regional Greenhouse Gas Initiative (RGGI).

Additionally, DEQ implements several programs to reduce methane DEQ also coordinates Virginia's participation in RGGI and the Transportation Climate Initiative (TCI).

GHG Inventories

DEQ has conducted economy-wide GHG inventories for 2005, 2010 and 2018. The following reports and accompanying Excel files provide more information on these inventories.

Baseline Inventory Report - 2005 and 2010

Baseline Inventory Tables and Figures Data

2018 Inventory Report

2018 Inventory Tables and Figures Data

Attachment 25

https://richmond.com/news/state-and-regional/govt-and-politics/61-dems-say-virginias-participation-in-rggi-is-up-to-legislature/article_86e0f575-2dc6-5e30-9b39-fa056de7a9f2.html

ALERT FEATURED

61 Dems say Virginia's participation in RGGI is up to legislature

Charlotte Rene Woods
Sep 8, 2022

Air Pollution Control Board Member Hope Cupit tells Virginia DEQ Director Mike Rolband that the Virginia attorney general's office gave her a document in March saying Virginia's participation in the Regional Greenhouse Gas Initiative is up to the General Assembly, not the Air Board.

On Thursday, 61 Virginia Democrats — more than a third of the General Assembly — signed onto a letter addressed to the state's **Air Pollution Control Board** opposing Gov. Glenn Youngkin's proposed regulatory route to remove Virginia from the Regional Greenhouse Gas Initiative.

On Aug. 31, **Travis Voyles**, the acting secretary of natural and historic resources, outlined the administration's plans to remove Virginia from RGGI through the Administrative Process Act — which entails a period of public comment and eventually a vote by the air board.

Download PDF

SENATE OF VIRGINIA

LYNWOOD W. LEWIS, JR.
6TH SENATORIAL DISTRICT
ALL OF ACCOMACK, NORTHAMPTON, AND MATHEWS COUNTIES; AND PART OF THE CITIES OF NORFOLK AND VIRGINIA BEACH

P. O. BOX 760
ACCOMAC, VIRGINIA 23301

COMMITTEE ASSIGNMENTS:
LOCAL GOVERNMENT, CHAIR
AGRICULTURE, CONSERVATION AND NATURAL RESOURCES
COMMERCE AND LABOR
EDUCATION AND HEALTH
RULES

September 8, 2022

Members of the Virginia Air Pollution Control Board
c/o Office of Regulatory Affairs
Department of Environmental Quality
P.O. Box 1105
Richmond, Virginia 23218

Sent via email: CitizenBoards@DEQ.Virginia.gov

Dear Members of the Air Pollution Control Board:

As current members of the Virginia General Assembly who voted for the Clean Energy and Community Flood Preparedness Act in 2020 or voted against changes to that same law in 2022, we write to express our continued support for Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI). Further, we write to articulate the reality that Virginia's participation in RGGI is mandated by *law*. Therefore, ultimately only a change in the *law* that passes both chambers of the General Assembly and is signed by the Governor can remove Virginia's participation. No proposed regulation, emergency regulation, regulatory act, or any subsequent administrative process can do so.

In addition to the Commonwealth's participation being mandated, RGGI is already delivering benefits to the residents of Virginia. As legislators, we believe it is important that you consider and understand the following benefits to Virginians from our participation in RGGI:

- RGGI has generated $378 million to support low-income energy efficiency programs and flood resilience infrastructure in Virginia.[1]
    - Energy efficiency upgrades are the best way to lower electricity bills, and Virginia's funds are directed to helping those households most in need.[2]
    - Flood resilience infrastructure protects Virginians against increased flooding and extreme weather events.
- RGGI has demonstrated Energy Cost Savings.
    - Electricity prices in RGGI states dropped by almost 6% while they went up by almost 9% throughout the rest of the country.[3] RGGI is a proven tool to reduce utilities'

[1] https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/Cumulative-State-Charts/VA_Proceeds_by_Auction.xlsx
[2] https://vaeec.org/rggi/
[3] https://acadiacenter.org/wp-content/uploads/2019/09/Acadia-Center_RGGI_10-Years-in-Review_2019-09-17.pdf

But the 61 legislators who have signed onto the letter say that's "improper and illegal" and that it's a decision for the General Assembly.

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RGGI is a carbon market composed of 11 states where energy producers trade emission reductions for credits or buy credits to emit carbon dioxide past a capped amount. Proponents of the initiative say it can incentivize producers to use fewer fossil fuels over time, and the funding generated through quarterly auctions is used for environmental projects. In 2021, Virginia raked in $228 million in funding for flood protection and energy efficiency programs.

Legislators mull ways to keep power bills down amid Regional Greenhouse Gas Initiative debate

The letter comes amid debates surrounding whose authority it is to pull Virginia out of RGGI. Environmental advocates, legal groups — and now many Democrats in the General Assembly — say that it's the legislative body's purview to remove Virginia from RGGI, that lawmakers put Virginia into the initiative.

"We write to articulate the reality that Virginia's participation in RGGI is mandated by law," the letter reads. "Therefore ultimately only a change in the law that passes both chambers of the General Assembly and is signed into law by the governor can remove Virginia's participation."

It seems that the attorney general's office might share that view. At an air board meeting this spring, member Hope Cupit said she received correspondence from the office reiterating the point.

Environmental advocacy group Appalachian Voices has a **pending lawsuit** in which it seeks to obtain a copy of the correspondence after it unsuccessfully requested the document under the Freedom of Information Act.

Environmental group sues to get AG document on withdrawal from RGGI

The letter, spearheaded by Sen. Lynwood Lewis, D-Accomack, added that the air board is limited in its abilities because it was created by the General Assembly.

"You only have the powers that the General Assembly grants you," the letter said.

The Democrats' letter also notes the law that enables participation in RGGI — the Clean Energy and Community Flood Preparedness Act — adding, "it is clear our intent for Virginia to participate in RGGI."

With Youngkin's proposed regulatory route, his goal is for Virginia to withdraw from the initiative by the end of 2023. The air board is composed of gubernatorial appointees on staggered terms, and with new appointees who could vote in Youngkin's favor, legal groups argue that this may trigger legal challenges.

Youngkin report calls carbon program too expensive; its supporters push back

Some members of the legislature have worked on a withdrawal, but efforts failed in the 2022 session. House Majority Leader Terry Kilgore, R-Scott, and Sen. Richard Stuart, R-Stafford, carried bills that would have repealed the Clean Energy and Community Flood Preparedness Act.

All General Assembly seats are up for election in 2023. Should the legislative body change its mind about RGGI, lawmakers would present such measures during the 2024 session.

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ARMENIAN FOOD FESTIVAL

Sept. 9-10

It's the 62nd year for the Armenian Food Festival, an area favorite dishing up shish kebabs, stuffed grape leaves, hummus and fresh baked items. Two days only this year: 11:30 a.m.-9:30 p.m. Friday and Saturday. St. James Armenian Church, 834 Pepper Ave. Free entry; pay as you go. **armenianfoodfestival.com**

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Attachment 26

ENERGY + ENVIRONMENT

Legislative commission objects to withdrawal from regional carbon market

BY: **CHARLIE PAULLIN** - DECEMBER 20, 2022 5:20 PM

Southern Environmental Law Center Senior Attorney Nate Benforado speaks to the Joint Commission on Administrative Rules Monday morning. (Charlie Paullin/The Mercury)

A legislative oversight commission voted 5-4 Monday to object to actions taken by Gov. Glenn Youngkin's administration earlier this month to repeal regulations governing Virginia's participation in a regional carbon market.

All Democrats on the Joint Commission on Administrative Rules voted in favor of the objection, while all Republicans voted against it.

The commission is charged with reviewing proposed regulations to see if they are consistent with the law. Its objection will be filed with the Virginia registrar and the State Air Pollution Control Board.

The vote followed action by the State Air Pollution Control Board Dec. 7 to start the process of withdrawing Virginia from the Regional Greenhouse Gas Initiative, a multistate carbon market that requires power producers to purchase allowances for every ton of carbon they emit.

Proceeds from the allowance purchases are returned to participating states, which in Virginia's case has resulted in $523 million for flood resilience and energy efficiency programs since January 2021.

Republican Gov. Glenn Youngkin's administration has described RGGI participation as a disguised tax because the costs incurred by the state's regulated electric utilities like Dominion and Appalachian Power are passed on to ratepayers. (Non-utility merchant generators, which are responsible for about a quarter of Virginia carbon emissions tracked by RGGI, bear the remaining costs.)

Acting Secretary of Natural and Historic Resources Travis Voyles defended the administration's withdrawal on the grounds that the 2020 law that led to Virginia's participation says the director of the Department of Environmental Quality is "authorized to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program."

The use of the word "authorize," said Voyles, provides discretion to the department to participate or not participate in RGGI.

Commission chair Creigh Deeds, D-Bath, however, said the first line of the code section states that the following provisions of the article "shall be incorporated by the department, without further action by the board."

"I think the mandatory outweighs the discretionary," he said.

Voyles said Deeds' interpretation was "mostly right" in that the law sets up the regulatory system for RGGI participation, but argued DEQ is responsible for any additional steps to implement the program.

No Republican members of the committee questioned the legality of the administration's efforts to leave the program. But Del. William Wampler, R-Washington, noted higher energy costs in other states participating in RGGI, such as Connecticut.

And in response to a question from Del. Roxann Robinson, R-Chesterfield, about whether a reduction in carbon emissions in Virginia can be directly related to RGGI, Voyles said "it's very hard" to attribute one to the other. Instead, he said recent reductions can be attributed to federal energy regulatory systems in place in the state and the Virginia Clean Economy Act, another 2020 Democrat-backed law that aims to decarbonize the electric grid by midcentury.

Southern Environmental Law Center Senior Attorney Nate Benforado, a leading proponent of RGGI participation, disputed that, pointing to data from a report issued by Youngkin's

administration that found carbon emissions fell from 32.8 million tons in 2020 to 28.6 million tons in 2021, a 12.8% difference.

The pool of available emissions allowances shrink every year under RGGI, he argued. Furthermore, he said, RGGI requirements also apply to Virginia's non-utility electricity producers, which are not subject to the Virginia Clean Economy Act.

"I don't think we should jump ship at this point," Benforado said.

All but one of several guest speakers spoke in favor of RGGI and the funding it provides to efforts across the entire state.

Last week, Republican Gov. Glenn Youngkin included in his 2023-24 budget proposal $100 million in each year for the Resilient Virginia Revolving Loan Fund, a pool of money that could serve as an alternative to RGGI funding now being channeled into flood resilience programs.

The administration has not identified an alternative state source of funding for existing low-income energy efficiency programs currently funded by RGGI dollars.

Youngkin spokesperson Macaulay Porter pointed to federal sources for weatherization efforts. Those include annual appropriations of $4.4 million from the U.S. Department of Energy and $14 million for the Low Income Home Energy Assistance Program, or LIHEAP, from the Secretary of Health and Human Service, plus $65 million to Virginia's Department of Housing and Community Development from the Infrastructure Investment and Jobs Act.

This story was updated with funding sources for weatherization efforts.

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CHARLIE PAULLIN

Charles Paullin covers energy and environment for the Mercury. He previously worked for Northern Virginia Daily in the Northern Shenandoah Valley and for the New Britain Herald in central Connecticut.

An Alexandria native, Charles graduated from the University of Hartford initially wanting to cover sports. He's received several Virginia Press Association awards for his coverage of crime, local government and state politics.

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Attachment 27

IN THE CIRCUIT COURT OF THE CITY OF RICHMOND

VIRGINIA MANUFACTURERS ASSOCIATION	)	
Petitioner,	)	
v.	)	**CASE NO. _____**
VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY, DAVID PAYLOR DIRECTOR, VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY, AND THE VIRGINIA STATE AIR POLLUTION CONTROL BOARD;	)	
Respondents,	)	

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PETITION FOR APPEAL

1. The Virginia Manufacturers Association (VMA), hereby petitions this court to invalidate, vacate, and declare null and void, Regulation Revision A20 to 9 VAC 5-140, Chapter 140, Regulation for Emissions Trading Programs (Final) (Revised Trading Rule) issued as a final rule by Virginia Department of Environmental Quality (DEQ), effective on July 10, 2020 and published in the Virginia Register on August 3, 2020. In compliance with

Rule 2A:2 of the Rules of the Supreme Court of Virginia, VMA filed a notice of appeal with the DEQ, and counsel on September 2, 2020. A copy of the notice of appeal is attached with this petition as Attachment A (Notice of Appeal).

INTRODUCTION

2. DEQ wrongfully issued the Revised Trading Rule (Revision A20) by determining that the revision is an exempt final regulation. As such, the Revised Trading Rule has had no economic impact analysis, no notice and comment by the public, no Air Pollution Control Board (Air Board) action on the rule, no legislative branch review, and no executive branch review. Revision A20 completely transformed the originally issued trading rule (Original Rule), at significant economic cost to the public, VMA, its member companies, and the Virginia economy. But there has been no analyses of the Revised Trading Rule or an opportunity to comment.

3. In compliance with Rule 2A:4 of the Rules of the Supreme Court of Virginia, VMA submits this petition for appeal within 30 days of filing its notice of appeal on October 2, 2020.

PARTIES

4. Petitioner VMA represents manufacturers across the Commonwealth of Virginia. Virginia's 6,750 manufacturers employ over 230,000 individuals, contribute $43 billion to the gross state product. VMA is the only statewide association in Virginia dedicated exclusively to manufacturers. Since 1922, the VMA has served as Industry's

Advocate.™ VMA develops constructive policies and activities on behalf of industry by serving as an advocate for legislative, regulatory, taxation, and environmental issues. VMA's core mission is to create the best business environment in the United States for world-class advanced technology businesses to manufacture and headquarter their businesses for maximum productivity and profitability. To fulfill this mission, VMA actively participates in the Commonwealth's regulatory processes. Petitioner VMA is a "person" as defined by Virginia Code Ann. §10.1-1300 because it is an association and a legal entity.

5. Respondent DEQ has the authority to draft regulations for action by the Air Board. Va. Code Ann. §§ 10.1-1308 and 10.1-1322.3. DEQ issued the Revised Trading Rule on behalf of the Air Board.

6. Respondent DEQ Director David Paylor may exercise the authority delegated to him by the Air Board and may designate other DEQ officials to exercise certain authorities on his behalf. In his position as Director, Mr. Paylor exercised his authority to issue the Revised Trading Rule.

7. Respondent Air Board is a regulatory board established by Section 10.1-1301 of the State Air Pollution Control Law, Virginia Code Ann. § 10.1-1301. The Air Board has authority to promulgate regulations, such as the Revised Trading Rule. DEQ acted under the Air Board's authority to issue the Revised Trading Rule.

JURISDICTION AND VENUE

8. Under Va. Code Ann. § 2.2-4026, any person has a right to the direct review by an appropriate and timely court action against the agency or its officers or agents if that person is affected by and claiming the unlawfulness of a regulation, whether that regulation is exempted from the procedural requirements of Article 2 of the APA.

9. VMA has standing to seek judicial review the DEQ's promulgation of the Revised Trading Rule as an exempt final regulation because (1) the Rule was unlawfully promulgated by DEQ; (2) the content of the Revised Trading Rule is unlawful; and (3) VMA, as an organization, and its members are adversely affected by the Rule.

10. As required by Virginia Code § 10.1-1318(B), VMA meets the standard for obtaining judicial review of a case or controversy pursuant to Article III of the United States Constitution. VMA, as an organization, and VMA's members have suffered actual, concrete, and particularized invasion of their legally protected interests, which is fairly traceable to the adoption of the Revised Trading Rule as a final rule. This harm is redressable by a favorable decision of the Court. U.S.C.A. Const. Art. 3, Section 1 *et. seq.*; *see also Chesapeake Bay Foundation, Inc. v. Commonwealth, ex rel. Virginia State Water Board*, 52 Va. App. 807 (Nov. 4, 2008).

11. The Revised Trading Rule directly and significantly affects VMA and its members. The Revised Trading Rule creates a Virginia only trading program. Based on the Revised Trading Rule, the Commonwealth joined the Regional Greenhouse Gas Initiative (RGGI) as a full member. Previously, Virginia was only a consignment member of RGGI with only administrative costs.

12. The Revised Trading Rule harms VMA's organizational interests to create the best business environment for businesses to have maximum productivity and profitability. The Rule will place Virginia business at a significant disadvantage due to increased electricity costs resulting from the Revision and causing businesses to expend extensive compliance costs and resource expenditures. VMA's members are adversely affected because they have an additional permitting and compliance burdens and will have significantly higher compliance costs and electricity costs directly traceable to the Revised Trading Rule.

13. Venue is proper in this Court under Va. Code Ann. § 2.2-4003, § 2.2-4026, and § 8.01-261(1). This Court is a preferred forum because VMA "[r]egularly or systematically conducts affairs or business activity" in the City of Richmond, pursuant to Va. Code Ann. § 8.01-261(1).

STATUTORY AND REGULATORY BACKGROUND

A. Virginia Administrative Process Act

14. DEQ's regulatory rulemaking role is to support rules and other actions of the Air Board. DEQ's website describes DEQ's role as:

> DEQ develops regulations for approval by Virginia's citizen regulatory boards that cover a wide variety of air, water and land protection issues. Regulations are intended to implement specific efforts directed by the Commonwealth's environmental laws. The adoption, change or repeal of any regulation usually is conducted in accordance with the Virginia Administrative Process Act and with the agency's public participation guidelines.

15. Agencies in the Commonwealth are subject to the Administrative Process Act (APA) when promulgating regulations. Va. Code § 2.2-4007.03 (Informational proceedings; effect of noncompliance). Unless a regulation is exempt, a regulation when proposed shall be published and go through notice and comment. If the regulation is revised after it is proposed, it shall go through notice and comment again. If APA procedures are not followed, "In no event shall the failure to comply with the requirements of this section be deemed mere harmless error for the purposes of § 2.2-4027." Va. Code Ann. § 2.2-4007.03(C).

16. DEQ also has its own regulations requiring notice and comment when taking any regulatory action including the promulgation or revision of regulations. 9 VAC 15-11-50.

17. Under the APA, DEQ must first provide a Notice of Intended Regulatory Action (NOIRA) and allow 30 days for public comment. Va. Code Ann. § 2.2-4007.01. After the comment period elapses, DEQ will issue a proposed regulation. The public will have an opportunity to comment on the proposed regulation in a public hearing in some cases. *Id.*

18. Before a proposed regulation can be published, DEQ shall submit the regulation to the Department of Planning and Budget (DPB) to prepare an economic impact analysis. Va. Code Ann. § 2.2-4007.04 (Economic Impact Analysis). The economic impact analysis must analyze the number of businesses and entities to which the regulation will apply; the number of persons and employment positions to be affected; costs on the use and

value of private property, and projected costs to affected businesses, localities, and entities of implementing or complying with the regulations. *Id.* The analysis also must analyze the impacts on small businesses in the Commonwealth. *Id.* If the proposed regulation is estimated to have an adverse economic impact on businesses or on a locality, business or entity particularly affected, DEQ must advise the Joint Commission on Administrative Rules, House Committee on Appropriations, and the Senate Committee on Finance. *Id.*

19. DEQ must follow APA guidelines to solicit public input of interested parties in the formation and development of its regulations. There is a general policy for the use of advisory panels and work groups to consult with DEQ on rule development. Va. Code Ann. § 2.2-4007.02. Before or after publication of the NOIRA, DEQ shall provide interested parties with the opportunity to submit data, views and arguments concerning the rulemaking. *Id.*

20. DEQ shall submit proposed regulations to the Virginia Registrar to be published. Va. Code Ann. § 2.2-4007.05. A 60-day notice and comment period shall be provided to the public for written comments, while 30 days is required for a reproposed regulation. 9 VAC 15-11-50(B).

21. Guidance documents are exempt from the APA but are subject to public notice and a 30-day public comment period. Va. Code Ann. § 2.2-4002.1.

22. The Air Board approves air pollution regulations under the APA. 9 VAC 5-5-50.

23. Upon Air Board approval of a final regulation, the regulation must undergo Executive branch review and Legislative branch review. Va. Code Ann. § 2.2-4013; § 2.2-4014.

24. Specific exempted rulemakings, known as exempt final regulations, from the requirements of the APA are outlined in Va. Code Ann. § 2.2-4006. Section 2.2-4006 enumerates sixteen types of rulemakings that are exempt from the APA. Of interest in this case, Section 2.2-4006(4)(a) provides an exemption for regulations that are "necessary to confirm to changes in Virginia statutory law or the appropriation act where no agency discretion is involved."

B. The Regional Greenhouse Gas Initiative

25. The Regional Green House Initiative (RGGI) is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to create a market-based program to cap and trade power sector CO2 emissions.[1] *See* www.RGGI.org.

26. RGGI is composed of individual CO2 Budget Trading Programs in each participating state. Through independent regulations, based on the RGGI Model Rule, each state's CO2 Budget Trading Program issues CO2 allowances and establishes participation in regional CO2 allowance auctions. RGGI purports to reduce CO2 emissions by returning money from CO2 allowance auctions to

[1] New Jersey participated as a RGGI member from 2009 to 2011.

participating states for reinvestment in programs promoting energy efficiency, clean and renewable energy, greenhouse gas abatement, and direct bill assistance. *See* www.RGGI.org.

27. RGGI is the first mandatory, market-based CO2 emissions trading program in the United States. Within the RGGI states, fossil-fuel-fired electric power generators with a capacity of 25 megawatts (MW) or greater (regulated sources) are required to hold allowances equal to their CO2 emissions over a three-year control period.

28. A CO2 allowance represents a limited authorization to emit one short ton of CO2 from a regulated source, as issued by a participating state. Regulated sources can use a CO2 allowance issued by any participating state to demonstrate compliance in any state. They may acquire allowances by purchasing them at regional auctions, or through secondary markets.

29. The cost of a CO2 allowance in the last RGGI auction was $6.82. *See* www.RGGI.org. It has ranged from $5.27 to $6.82 from 2019-2020 based on auction results, steadily increasing over the years by the design of the program. *Id.*

C. Virginia Regulation for Emissions Trading Programs

30. The Virginia initiative to adopt a CO2 cap and trade program began on May 16, 2017, when then Governor McAuliffe issued Executive Directive 11 (2017), "Reducing Carbon Dioxide Emissions from the Electric Power Sector and Growing Virginia's Clean Energy Economy." ED 11 directed the DEQ Director, in coordination with the Secretary of Natural Resources, to develop a regulation to control CO2 from electric power facilities that

allows for the use of market-based mechanisms and the trading of CO2 allowances through a multi-state trading program.

31. DEQ published the proposed CO2 cap and trade rule on January 8, 2018 (the Original Trading Rule). The Original Trading Rule called for RGGI consignment membership. The Rule provided "conditional" CO2 allowances to utilities and non-exempt manufacturers that generate electricity, requiring participation in a consignment auction. The conditional allowances were to be contributed into the RGGI auction market with an equal number of allowances (or the number necessary to offset CO2 emissions tons) purchased back from the market. The money that consignment participants paid into the market for allowances would then be returned *directly* to the participant (utility or non-exempt industrial source) from RGGI minus a three percent administration fee. The Original Rule did not require that participants purchase all necessary allowances from the RGGI market. Therefore, the only money to be paid was the three percent administrative fee to RGGI.

32. The Original Trading Rule applied to any fossil fuel-fired unit that services an electricity generator with a nameplate capacity equal to or greater than 25 MWe (typically utility units). There is an exemption for existing manufacturing facilities that supply less than or equal to 10% of their annual net electrical generation to the electric grid or supply less than or equal to 15% of their annual total useful energy to any other entity than the facility itself. Only existing manufacturing facilities prior to January 1, 2020 can avail themselves of this exemption. In summary, the Original Trading Rule applied to sources

that are larger than the applicability threshold and that did not qualify for the exemption. 9 VAC 5-140-6040. The Revised Trading Rule maintains these applicability criteria and the exemption.

33. DEQ went through a full notice and comment process for the Original Trading Rule. As part of the rulemaking process, the rule was re-proposed on February 4, 2019. There was a public comment period for the re-proposal of the Original Trading Rule. VMA submitted extensive written comments in both dockets.

34. The State Corporation Commission (SCC) and the DPB examined the costs of the Original Trading Rule. Even though the Original Trading Rule only required consignment auction RGGI participation with a non-returnable administrative fee of three percent, the cost estimates for the Original Trading Rule to Dominion Energy (Dominion) customers ranged from $3.3 Billion for not linking to RGGI to $5.9 Billion[2] for linking to RGGI. *See* Attachment B (SCC Cost Analysis).

35. The Original Trading Rule was adopted in final form on April 19, 2019 and published May 27, 2019 as a new Chapter 9 VAC 5-140, adding 9 VAC 5-140-6010 through 6440 to the Air Board regulations.

36. Subsequently, the General Assembly passed budget language restricting DEQ's ability to incur any expenses in the implementation of the Original Trading Rule. As a result, Virginia did not join RGGI as a consignment member on January 1, 2020, as

[2] The SCC Report provides an estimate for "linking" to RGGI which is the same as consignment membership.

planned, even though the Original Trading Rule was final. The budget restriction was lifted in the 2020 General Assembly session.

D. The Clean Energy and Community Flood Preparedness Act

37. The 2020 General Assembly passed Chapter 1219 of the 2020 Acts of Assembly, which amended the Air Pollution Control Law to add a new Article 4, Clean Energy and Community Flood Preparedness Act (CECFPA or the Act). Va. Code Ann. § 10.1-1329 *et seq.* *See* Attachment C (2020 Virginia Assembly Session, Chapter 1280, Article 4 "Virginia Clean Energy and Community Flood Preparedness Act").

38. The CECFPA authorizes DEQ to establish, implement, and manage an auction program to sell allowances into a market-based trading program. The Act acknowledges that DEQ has the optionality to comply with the Act by joining RGGI, another carbon trading program with an open carbon trading market, or by simply implementing the Original Trading Rule. Va. Code Ann. § 10.1-1331.

39. The CECFPA provides that, if Virginia receives funds from an allowance auction, the state treasury shall "(i) hold the proceeds recovered from the allowance auction in an interest-bearing account with all interest directed to the account to carry out the purposes of this article and (ii) use the proceeds without further appropriation" as the CECFPA provides "to the extent permitted by Article X, Section 7 of the Constitution of Virginia." The Act directs forty-five percent of the revenue to be credited to the account established pursuant to the Fund for the purpose of assisting localities and their residents

affected by recurrent flooding, sea level rise, and flooding from severe weather events. Fifty percent of the revenue shall be credited to an account administered by Department of Housing and Community Development (DHCD) to support low-income energy efficiency programs, including programs for eligible housing developments. Three percent of the revenue shall be used to cover reasonable administrative expenses of DEQ. Finally, the remaining two percent of the revenue shall be used by the DHCD, in partnership with the Department of Mines, Minerals and Energy (DMME), to administer and implement low-income energy efficiency programs pursuant to subdivision.

40. Under CECFPA Section 10.1-1330(A), the Act directs that: "[T]he provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019 [Original Rule], and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 *et seq.*)." Thus, the CECFPA authorizes DEQ, on behalf of the Air Board, to incorporate the statutory provisions of the Act into the Trading Rule, but nothing more.

41. The CECFPA dictates that the costs of allowances purchased through the market-based trading program will be deemed to constitute environmental compliance project costs that may be recovered by a Phase I Utility or Phase II Utility. This provision clarifies that if a utility must purchase CO2 allowances for the Act, that utility can recover the allowance costs from electricity customers. In other words, the customer purchasing power from the utility will bear the cost of CO2 allowances.

42. In summary, the CECFPA provides a limited exemption from the APA for DEQ to incorporate the provisions of the Article into the Existing Rule. Va. Code Ann. § 10.1-1330(A). It does not contain an open-ended APA exemption.

E. Revision A20 to the Virginia Regulation for Emissions Trading Programs

43. On July 10, 2020, DEQ issued Revision A20 in final, revising the Original Trading Rule to issue the Revised Trading Rule. The Revised Trading Rule was published in the Virginia Register on August 3, 2020. The Revised Trading Rule was not issued as a proposed rule first, nor were stakeholders consulted for feedback or provided a pre-draft. The Revised Trading Rule did not go through the APA rulemaking process, such as publication of the proposed changes, public comment, action by the Air Board, economic analysis or review by the executive or legislative branches. Rather, DEQ designated Revision A20 as an exempt final regulation from the APA. DEQ, in consultation with the Attorney General's Office, determined that "this regulation is exempted from the Virginia Administrative Process Act, §§ 2.2-4000 *et seq.*, by its enabling legislation," pointing to the CECFPA. *See* Attachment D (Memorandum from G. O'Dwyer regarding Proposed Exempt Regulations – 9 Va. Admin. Code §§ 5-140 *et seq.* (dated July, 09, 2020)).

44. The Revised Trading Rule purports to amend the Original Trading Rule to confirm to the requirements in the CECFPA. The Revised Trading Rule creates a Virginia only rule requiring participants to obtain CO2 allowances and participate in trading and auctioning requirements beginning on January 1, 2021. Sources have begun compliance efforts in preparation for the program start date.

45. The Revised Trading Rule transforms the Original Trading Rule from a consignment auction process to a trading rule that contemplates full participation in the multi-state trading program RGGI, although RGGI is not specifically identified in the Rule.

46. DEQ has announced that Virginia has joined RGGI, Inc. *See* https://www.deq.virginia.gov/Programs/Air/GreenhouseGases/CarbonTrading.aspx Participating states in RGGI, Inc. must sign a contract. *See, e.g.*, https://www.rggi.org/rggi-inc/documents. Presumably, Virginia signed a contract with RGGI, Inc., although it is not publically available.

47. The Revised Trading Rule assumes that Virginia participants will purchase allowances in quarterly auctions held by RGGI, Inc. throughout the calendar year or acquire allowances via private trades with other participants. These allowances will be placed in the compliance account for the source to cover every ton of CO2 it emits. Virginia has a CO2 base budget for 2021 of 27.16 million allowances, which is not an emissions cap but simply the number of allowances that came into the RGGI market for the Commonwealth. 9 VAC 5-140-6190. Cumulatively, Virginia sources may emit more than the Commonwealth's base budget of allowances, if their compliance accounts contain the proper number of allowances for each ton of CO2 emitted. RGGI, Inc. reported orally in the DEQ hosted webinar, "What you need to know about the Virginia Carbon Trading Rule and Participation in RGGI" on August 12, 2020 that no RGGI source has ever had to curtail its operations to reduce CO2 emissions due to allowance scarcity.

48. RGGI, Inc. provides guidance materials on its website that provide clarity on the mechanics of the program, such as how auction funds are handled, auction materials essential to accessing the auctions, and program management details. *See* www.RGGI.org. Sources will be participating in auctions to buy allowances, and Virginia will be participating in the auctions to sell the allowances.

49. DEQ exercised its discretion to determine the type of auction to satisfy the CECFPA. DEQ then knitted together a full auction rule from the existing consignment rule, using RGGI as a guidepost. To achieve this goal, DEQ made substantive decisions to add, delete, and revise the majority of the Original Rule. As examples, the Revised Trading Rule revises and deletes many definitions; modifies the Applicability section (9 VAC 5-140-6040); repeals 9 VAC 5-140-6045, 9 VAC 5-140-6211, 9 VAC 5-140-6215, 9 VAC 5-140-6430 and 9 VAC 5-140-6435; deletes provisions pertaining to the consignment auction; reworks the allocation provision in 9 VAC 5-140-6210, including adjustment of allocation years; and incorporates new auction provisions and deletes consignment auction requirements (*See, e.g.*, 9 VAC 5-140-6210). There are few provisions in the Original Trading Rule that have not been revised to some extent.

50. Absent from the Revised Trading Rule are most of the provisions of the CECFPA that the General Assembly directed DEQ to incorporate without notice and comment. DEQ only incorporates the language from CECFPA Section 10.1-1331(1), which contains language specific to one power producer. It is not of general application. 9 VAC 5-140-6325 (Life-of-unit contractual arrangements).

51. Among the provisions of the CECFPA not incorporated into the Revised Trading Rule as required by Section 10.1-1330(A) are Section 10.1-1329 (Definitions) and Section 10.1-1330(C), which directs how to collect and allocate the proceeds from the auction of CO2 allowances. Presently, the Revised Trading Rule requires utilities to acquire costly allowances, collecting a tax on carbon emissions. But the Rule is silent as to where auction proceeds go when returned to the Commonwealth after the auction. Section 10.1-1330(C) is the most substantive and impactful part of the CECFPA but is not included in the Revised Trading Rule. The Rule also does not direct revenues from RGGI to be paid into the General Treasury. *See* Article X, Section 7 of the Constitution of Virginia.

52. The Director exercised his discretion to add a requirement for exempt industrial sources. Exempt industrial sources shall have "an operating permit containing the applicable restrictions . . . . An application for such operating permit shall be submitted to the department no later than January 1, 2022." 9 VAC 5-140-6040(B). This language appears nowhere in the CECFPA.

53. With respect to cost of the Revised Trading Rule, DEQ did not send the Revised Trading Rule for an economic impact analysis by the DPB. Regardless, the Revised Trading Rule will impose hefty cost on VMA and its members, further impacting businesses that are already experiencing an economic downturn due to the COVID19 pandemic.

54. Utilities and non-exempt manufacturers must purchase CO2 allowances for *each ton of CO2 emitted from sources in Virginia that serve an electricity generator* at an

approximate auction cost of between $6.00 and $13.00 in 2021, which is the fixed price range by RGGI that is incorporated in the Revised Trading Rule. 9 VAC 5-140-6020 at Tables 140-1A and Table 140-1B.

55. Dominion provides electricity to most industrial, commercial and residential customers in Virginia, serving the most populated areas of the state (Richmond, Norfolk/Virginia Beach, and Northern Virginia near Washington, D.C.). *See* Attachment E (EIA Form 861 Virginia Service Provider Data, 2018). VMA is located in the Dominion service area, as do a significant number of its members. To conceive of the magnitude of the RGGI carbon tax, it is important to realize that Dominion emitted at least 30,000,000 CO2 tons in 2019.

56. Utilities will not pay the RGGI carbon tax. Rather, CECFPA allows utilities to recover the cost of purchase of CO2 allowances as an "environmental compliance project" cost subject to rate recovery. This mechanism allows the RGGI tax to be passed to VMA, its members, and all electricity customers.

57. The Dominion Integrated Resource Plan (IRP) dated May 1, 2020 projects that in 2021 alone its sources will emit between 26,000,000-28,000,000 tons of CO2. *See* Attachment F (IRP) at 25-26. Using 27,000,000 tons of CO2 and multiplying by the *minimum* CO2 allowance price in the Revised Trading Rule for 2021 of $6.00, the total electricity cost impact solely for 2021 is $162,000,000. Participation in RGGI will continue until at least 2030. The Dominion IRP includes a Net Present Value cost of Virginia in RGGI under Dominion's preferred operating scenario through 2030 to be $65.7 billion

dollars. IRP at 61. The IRP also analyzes the monthly bills of a typical residential rate payer who pays $122.66 per 1,000kWh per month as of December 31, 2019. The IRP then calculates the average ratepayer cost across the existing RGGI states, which is $184 per kWh, an approximately 50% higher than the $122.66 per kWh rate. IRP at 32-33. The same rate increases will be passed along to industrial and commercial customers. In summary, the Dominion IRP confirms Dominion's intent to pass these staggering RGGI costs to customers.

ASSIGNMENTS OF ERROR

CLAIM I

DEQ violated the Administrative Process Act by issuing the Revised Trading Rule as a final rule without any direct statutory exemption from APA requirements.

58. Allegations 1 through 57 are incorporated and re-alleged herein.

59. Under Section 10.1-1330(A), the Act directs that: "[T]he provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 *et seq.*)."

60. The CECFPA only authorizes DEQ to incorporate the statutory provisions of the Act into the Trading Rule.

61. Although the limited exemption language from the APA pertains to adoption of the provisions of the CECFPA, DEQ wrongfully broadened the statutory exemption by taking action on the Act's authorization for the Director of DEQ to "establish, implement, and manage an auction program to sell allowances into a market-based trading consistent with the RGGI program and this article." CECFPA, § 10.1-1330(B).

62. The Revised Trading Rule is a significant revision to the Original Trading Rule. The program outlined by the Revised Trading Rule is dramatically different on its face, in operation, and in expense to all citizens of the Commonwealth. There is no direct statutory authorization for DEQ to use its discretion to revise the Original Trading Rule by adding new cap and trade provisions without adhering to the APA.

63. Respondents erred by failing to comply with the statutory authority of the APA and CECFPA upon issuance of the Rule. *See* Va. Code Ann. § 2.2-4027(ii) (Issues on Review).

64. Respondents erred by failing to observe required procedure under the APA, which cannot be mere harmless error. *See* Va. Code Ann. § 2.2-4027(iii) (Issues on Review).

CLAIM II

DEQ violated the Administrative Process Act by issuing the Final Trading Rule because none of exemptions identified in APA Section § 2.2-4006 apply.

65. Allegations 1 through 64 are incorporated and re-alleged herein.

66. DEQ periodically issues exempt final regulations because they are subject to the exemption from the APA for regulations that are: "Necessary to confirm to changes in Virginia statutory law or the appropriation act *where no agency discretion is involved.*" Va. Code Ann. § 2.2-4006(A)(4)(a) (emphasis added).

67. The Act directed DEQ to "establish, implement, and manage an auction program to sell allowances into a market-based trading consistent with the RGGI program and this article." Section 10.1-1330(B). To carry out this directive, DEQ must exercise its discretion to decide: (1) the type of market-based program to develop and whether full membership in RGGI is an appropriate fit for the Commonwealth; (2) the provisions to add and revise the program design; and (3) the requirements for implementation.

68. DEQ gutted and revamped the Original Trading Rule from a consignment to a full auction program.

69. Due to the considerable amount of discretion DEQ exercised, the Revised Trading Rule is not an exempt final regulation under Va. Code Ann. § 2.2-4006(A)(4)(a). It is not exempt under any other provision in Section 2.2-4006.

70. The Director used his discretion not to incorporate the entire CECPA into the Revised Trading Rule. His exercise of discretion precludes the avoidance of notice and comment rulemaking, particularly when the statute provides him with no such authority.

71. Respondents erred by failing to comply with statutory authority of the APA and CECFPA upon issuance of the Rule. *See* Va. Code Ann. § 2.2-4027(ii) (Issues on Review).

72. Respondents erred by failing to observe required procedure under the APA, which was not mere harmless error. *See* Va. Code Ann. § 2.2-4027(iii) (Issues on Review).

CLAIM III

DEQ violated the Administrative Process Act by issuing the Revised Trading Rule with a provision that creates a permitting burden for certain industrial sources without any APA exemption.

73. Allegations 1 through 72 are incorporated and re-alleged herein.

74. The Revised Trading Rule added language requiring exempt sources to apply for and obtain permits under the new CO2 trading program.

75. The CECFPA does not address exempt industrial sources at all, much less requiring exempt industrial sources to apply for and obtain a permit from DEQ.

76. Since there is no statutory basis for this new permitting requirement, procedurally, it must be vetted through the APA process. It is not exempt and is therefore unlawful.

77. Respondents erred by failing to comply with statutory authority (APA) upon issuance of the Rule. *See* Va. Code Ann. § 2.2-4027(ii) (Issues on Review).

78. Respondents erred by failing to observe required procedure under the APA, which cannot be mere harmless error. *See* Va. Code Ann. § 2.2-4027(iii) (Issues on Review).

CLAIM IV

DEQ is not authorized to levy a carbon tax on electricity customers in Virginia.

79. Allegations 1 through 78 are incorporated and re-alleged herein.

80. The Revised Trading Rule was issued by the DEQ. The Revised Trading Rule requires the purchase of CO2 allowances, at a significant cost to Revised Trading Rule participants. The Revised Trading Rule imposes a hidden tax on program participants.

81. The Virginia Constitution states, "All taxes, licenses, and other revenues of the Commonwealth shall be collected by its proper officers and paid into the State treasury." Va. Constitution, Article X, Section 7.

82. The Power to tax is given only to the General Assembly. No delegation has occurred with respect to the DEQ. DEQ is not a proper officer to collect this tax as defined by the Constitution. Therefore, the tax is illegal. *Wise County Bd. of Supvrs. v. Wilson,* 250 Va. 482, 463 S.E.2d 650 (1995).

83. Respondents erred by acting outside of their constitutional rights, powers, and privileges upon issuance of the Rule. *See* Va. Code Ann. § 2.2-4027(i) (Issues on Review).

CLAIM V

The Revised Trading Rule is fatally flawed because it levies a tax on carbon emissions but does not provide for return of the monies to Virginia's Treasury in accordance with the Virginia Constitution.

84. Allegations 1 through 83 are incorporated and re-alleged herein.

85. The Revised Trading Rule requires the purchase of CO2 allowances, at a significant cost to RGGI participants. Proceeds from these purchases are returned to the Commonwealth by RGGI, Inc.

86. The Virginia Constitution requires that "[a]ll taxes, licenses, and other revenues of the Commonwealth shall be collected by its proper officers and paid into the State treasury. No money shall be paid out of the State treasury except in pursuance of appropriations made by law." Virginia Constitution, Article X, Section 7.

87. The CECFPA acknowledges this Constitutional requirement and concern:

> To the extent permitted by Article X, Section 7 of the Constitution of Virginia, the state treasury shall (i) hold the proceeds recovered from the allowance auction in an interest-bearing account with all interest directed to the account to carry out the purposes of this article and (ii) use the proceeds without further appropriation for the following purposes . . . 10.1-1330(C)

88. The Revised Trading Rule provides for the collection of money and there are implied RGGI contractual obligations to provide for return of that money to the Commonwealth. However, *even though directed by the General Assembly in the CECFPA*, DEQ failed to incorporate provisions to address these revenues. Since the Rule contains no

provisions to ensure compliance with the Virginia Constitution, the trading program in the Revised Trading Rule is unlawful, and Rule must be struck.

89. Respondents erred by acting outside of their constitutional rights, powers, and privileges upon issuance of the Rule. *See* Va. Code Ann. § 2.2-4027(i) (Issues on Review).

CLAIM VI

The Revised Trading Rule is unlawful because it does not provide an authorization for DEQ to join RGGI and does not provide adequate detail to enable participants to implement its provisions without reliance on requirements, procedures, and guidance from RGGI, Inc., which are not incorporated into any Virginia statute or regulation.

90. Allegations 1 through 89 are incorporated and re-alleged herein.

91. The Revised Trading Rule provides a basic framework for a full CO2 trading auction process. But details concerning such key operational aspects are missing, such as how and when auctions will occur?; How will costs from the auction be divided amongst the participating states and returned to the DEQ?; Is DEQ the party that signed the RGGI participation agreement?; How will trades be made?; How will utilities bid into the market?; How will winning bids be determined?; How will the resulting trades be executed?; Will RGGI or a third-party run the auction; and How permitting will work? Therefore, the Revised Trading Rule is substantively flawed.

92. The Rule does not contain the word "RGGI" or "Regional Greenhouse Gas Initiative" in any its provisions or provide a specific contractual authorization for DEQ to join RGGI.

93. Since requirements are missing, DEQ implies that sources look to the documentation on the RGGI, Inc. website, such as the RGGI COATS User's Guide and specific sections of the RGGI, Inc. website (www.rggi.org) to fill-in-the-blanks. None of the RGGI, Inc. requirements or guidance have been incorporated into Virginia regulation or guidance. The lack of specificity in the Revised Trading Rule is illegal because DEQ is forcing sources to comply with private organization requirements that have no legal basis in the Commonwealth without going through the APA rulemaking process.

94. Respondents erred by failing to comply with statutory authority (APA) upon issuance of the Rule. *See* Va. Code Ann. § 2.2-4027(ii) (Issues on Review).

RELIEF REQUESTED

VMA respectfully requests that this Court grant the following relief:

1. That this Court invalidate, vacate, and declare the Revised Trading Rule null and void.
2. That this Court, under the authority of Va. Code Ann. § 2.2-4030, award Petitioner its reasonable costs and attorneys' fees; and
3. That this Court grant such other relief as may appear to be just and proper.

Respectfully Submitted,

Virginia Manufacturers Association

Elizabeth C. Williamson (Virginia State Bar No. 72048)
John M. Holloway III (Virginia State Bar No. 72048)

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ATTACHMENT A

NOTICE OF APPEAL

RECEIVED
SEP 02 '20
DEQ - OD
CM Berndt
RECEIVED
SEP 03 '20
DEQ - OD

COMMONWEALTH OF VIRGINIA

BEFORE THE STATE AIR POLLUTION CONTROL BOARD

IN RE: State Air Pollution Control Board
Final Regulation 9 VAC §§ 5-140 *et seq.*
Regulation for Emissions Trading Programs
Amending 9 VAC § 5-140-6010 through 9 VAC § 5-140-6440

NOTICE OF APPEAL

In accordance with Rule 2A:2 of the Rules of the Supreme Court of Virginia, the Virginia Manufacturers Association ("Appellant" or "VMA") hereby files this notice of appeal with David K. Paylor, Executive Secretary of the Virginia State Air Pollution Control Board, for judicial review of the Virginia Department of Environmental Quality's amendments of the Regulation for Emissions Trading Programs (9 VAC §§ 5-140 *et seq.*) as a final regulation, effective on July 10, 2020.

The appeal of this case decision will be taken to the Circuit Court for the City of Richmond, 13th Judicial Circuit of Virginia, located at 400 North Ninth Street, Richmond, Virginia 23219. Under Rule 2A:3 of the Rules of the Supreme Court of Virginia, the agency record should be forwarded to the Clerk of the Circuit Court for the City of Richmond as soon as possible.

As required by Rule 2A:2(b) of the Rules of the Supreme Court of Virginia, the Appellant provides the following information:

1. The Appellant is:

   Virginia Manufacturers Association
   2108 W. Laburnam Ave, Suite 230
   Richmond, VA 23227

2. Counsel for the Appellant is:

Elizabeth C. Williamson, Esq.
John M. Holloway, Esq.
Williams Mullen
200 South 10th Street
Richmond, VA 23219

3. The Appellee is:

Virginia State Air Pollution Control Board
Virginia Department of Environmental Quality
c/o David K. Paylor, Executive Secretary and Director
1111 East Main Street St., Suite 1400
Richmond, VA 23219

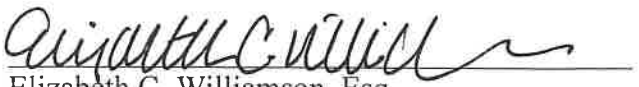
4. Counsel for the Appellee is:

Mark R. Herring, Attorney General of Virginia
Gray O'Dwyer, Assistant Attorney General
Office of the Attorney General of Virginia
202 North Ninth Street
Richmond, VA 23219

Dated: September 2, 2020

Respectfully submitted,

Virginia Manufacturers Association



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CERTIFICATE OF SERVICE

I hereby certify that on September 2, 2020, I have hand-delivered a complete copy of the foregoing Notice of Appeal to Appellee and its counsel identified above.

Elizabeth C. Williamson

43296978_1

ATTACHMENT B

SCC COST ANALYSIS

William F. Stephens
Director
(804) 371-9611
FAX (804) 371-9350

COMMONWEALTH OF VIRGINIA

PO Box 1197
Richmond, Virginia 23218-1197

STATE CORPORATION COMMISSION

Division of Public Utility Regulation

February 27, 2019

Delegate Charles D. Poindexter
Virginia House of Delegates
Post Office Box 117
Glade Hill, Virginia 24092

Dear Delegate Poindexter:

I am responding to your letter dated February 15, 2019 requesting SCC Staff responses to questions you raise concerning proposed regulations capping CO2 emissions from the Commonwealth's regulated electric power plants. These proposed regulations concern the Commonwealth linking to the Regional Greenhouse Gas Initiative ("RGGI").

Enclosed for your review is a document that the SCC Staff recently prepared at the request of the Virginia Department of Environmental Quality ("DEQ") to explain the methodology and assumptions used by SCC Staff. The document provides SCC Staff analysis supporting our bill impact estimates that a typical monthly residential bill for Dominion Energy Virginia ("DEV") will increase between $7 and $12 depending on whether Virginia *links* to RGGI or *joins* RGGI.

Answers to your specific questions and requests for information, to the extent that the SCC Staff can provide them, are detailed below:

1. CO2 annual emissions from 2009 through 2018 for:
   a. The Commonwealth's regulated electric power plants.
   b. All other unregulated sources of CO2.

   Inasmuch as the SCC does not regulate or track historic CO2 emissions for either regulated electric power plants or unregulated sources of CO2, we do not maintain any data relative to carbon emissions. The DEQ has regulatory authority relative to environmental issues in the Commonwealth and is the appropriate source of emissions data.

2. The forecast of CO2 emissions beginning in 2019 under the latest integrated resource plans for regulated electric power plants.

   DEV's 2018 Integrated Resource Plan ("IRP") (not approved by the Commission as filed) incorporated the initial proposed CO2 emissions cap for Virginia of 34 million tons rather than the currently proposed 28 million tons. The SCC Staff believes it would be more relevant to provide the CO2 emissions forecast modeled in the SCC Staff's RGGI analysis which used the current proposed cap of 28 million tons. This CO2 forecast is enclosed.

3. The annual CO2 emissions allowed through 2040:
   a. Under the original DEQ proposal (34 million ton 2020 budget base, 3% reductions per year, no reductions beyond 2030).
   b. Under the new re-proposal using a 28 million ton 2020 budget, 3% reductions per year through 2030, and annual reductions of 840,000 tons per year from 2031 to 2040.

   The requested information is enclosed.

4. An estimate of the annual cost of the "allowance fees" purchased through 2040 to be passed through to consumers based on the minimum price and double the minimum price.

   See page 14 of the enclosed document. The SCC Staff's analysis estimated the annual cost of the allowance fees through 2030 based on the RGGI Emission Containment Reserve trigger prices. RGGI has not published any prices beyond 2030.

5. An estimate of the plants that would be shutdown to comply with the emission caps and the change in natural gas deliveries as a result.

   The SCC Staff's analysis concludes that linking to RGGI will result in the premature retirements of DEV'S Chesterfield Units 5 and 6 and Clover Units 1 and 2. Since these are coal units, there are no related impacts to natural gas deliveries.

6. An estimate of the capacity and emissions from the plants required to provide power when solar and wind plants are not able to supply the power demand.

   DEV's units are dispatched by the PJM Interconnection, LLC ("PJM"). PJM dispatches power generation from a mix of nuclear, coal, gas, and renewable generating units owned by PJM member utilities (including DEV) operating in

the PJM Interconnection.[1] When individual solar and wind plants in Virginia or elsewhere in the Interconnection are not available for any reason (forced outages, weather, etc.), the power these units would have furnished will be supplied from the mix of other available generation plants (of all types) located throughout the PJM footprint. Further, if additional generation is needed to meet load during a time of high demand within the Interconnection, PJM simply dispatches from the mix of generation then available to meet load requirements. Consequently, the information requested in this question cannot be provided because of the way in which PJM dispatches the generation of its member utilities.

7. Evaluation of the proposal using the SCC's standard analysis including the Ratepayer Impact Measure. Please provide estimates of the residential, commercial and industrial rates from 2020 through 2040 assuming no return of allowance revenue to consumers as was contemplated in legislation defeated in the General assembly.

   See pages 7-8 of the enclosed document. Staff only provides a high-level bill impact for a typical DEV residential customer. Determining actual rate impacts by year through 2040 for all of DEV's rate classes is beyond the scope of the RGGI analysis that the SCC Staff performed. DEV has very complex non-residential rate structures and many different non-residential rate classes. This fact coupled with the wide diversity of customers within these classes makes such an analysis extraordinarily complex. Additionally, we would have little confidence in the results of such an analysis.

8. Estimates of the amount of power purchased annually from the PJM grid during the 2020-2040 cap regime.

   As a member of PJM, DEV purchases 100% of the power it consumes from PJM and it sells 100% of the power its generating units produce into PJM. Staff's estimate of total sales to PJM, purchases from PJM, and net purchases in excess of sales is enclosed.

9. Experience from other RGGI states between 2007 and 2016 shows an increase in imports of power from other states in the PJM grid as in-state power generation falls because of allowance prices. There was also a significant loss of in-state production of energy intense goods that shifted to other states. What is the SCC estimate of carbon dioxide emission shifting from these two causes? Shouldn't the estimates be included as costs to the RGGI program?

[1] The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Any changes to imported power from PJM and changes in the dispatch of DEV's fossil fuel units is captured in Staff's RGGI analysis. The SCC Staff has not estimated loss of in-state production of energy intense goods as its analysis was limited to the costs of providing electricity and related customer bill impacts of RGGI compliance.

10. The estimates of the Cost Containment Reserve (CCR) allowance price and the Emission Containment Reserve (ECR) trigger price appear to be based on the discredited Social Cost of Carbon proposed by the Obama Administration. Can you confirm how these two prices were developed?

    The SCC Staff cannot confirm how the Cost Containment Reserve allowance price or the Emission Containment Reserve price were calculated or what formed the basis of those calculations.

If you have any other questions or need additional assistance, please contact me or Greg Abbott at 804-371-9611.

Respectfully,

William Stephens

Enclosures

SCC STAFF RGGI ANALYSIS FORECAST OF CARBON EMISSIONS FOR DEV

CARBON (TONS)

	No CO2 Base	No CO2 GTSA	RGGI Link GTSA
2018	28,858,477	28,858,477	28,858,477
2019	29,215,747	29,115,197	29,131,044
2020	30,036,685	29,524,359	26,488,641
2021	28,923,203	28,115,865	25,240,860
2022	29,334,792	28,142,628	25,715,612
2023	30,096,952	28,727,137	25,617,605
2024	29,921,839	28,181,266	24,970,901
2025	30,180,823	27,732,939	24,767,813
2026	29,619,643	26,607,941	24,441,398
2027	31,179,184	27,965,381	26,013,263
2028	30,336,483	26,499,684	22,956,099
2029	31,132,829	27,318,300	24,424,271
2030	30,346,024	26,771,111	22,877,523
2031	30,570,478	26,680,186	22,772,674
2032	29,637,821	26,180,204	21,024,971
2033	32,369,828	28,661,945	24,088,127
2034	30,600,303	27,648,989	22,098,659
2035	33,227,067	30,240,431	25,135,606
2036	33,420,559	31,065,660	25,469,431
2037	33,999,904	31,546,764	25,456,153
2038	34,245,693	32,175,343	26,035,008
2039	34,420,443	32,567,542	26,056,592
2040	34,732,142	32,999,597	25,935,143
2041	34,829,607	33,261,042	25,987,079
2042	35,529,933	34,017,314	26,302,759
2043	35,746,249	34,374,286	26,629,909

ANNUAL CO2 EMISSIONS ALLOWED THROUGH 2040
UNDER ORIGINAL DEQ PROPOSAL AND UNDER THE CURRENT PROPOSAL

	Orginal Proposal VA RGGI Carbon Cap (tons)	Current Proposal VA RGGI Carbon Cap (tons)
2020	34,000,000	28,000,000
2021	32,980,000	27,160,000
2022	31,960,000	26,320,000
2023	30,940,000	25,480,000
2024	29,920,000	24,640,000
2025	28,900,000	23,800,000
2026	27,880,000	22,960,000
2027	26,860,000	22,120,000
2028	25,840,000	21,280,000
2029	24,820,000	20,440,000
2030	23,800,000	19,600,000
2031	23,800,000	18,760,000
2032	23,800,000	17,920,000
2033	23,800,000	17,080,000
2034	23,800,000	16,240,000
2035	23,800,000	15,400,000
2036	23,800,000	14,560,000
2037	23,800,000	13,720,000
2038	23,800,000	12,880,000
2039	23,800,000	12,040,000
2040	23,800,000	11,200,000

SCC STAFF RGGI ANALYSIS
Estimates of Power Sold/Purchased from PJM
MWh

	DEV Generation Sold to PJM	DEV Purchases From PJM	DEV Net Sales/(Purchases)
2020	84,946,957	91,974,332	(7,027,375)
2021	82,986,266	92,615,967	(9,629,700)
2022	84,770,240	93,916,547	(9,146,308)
2023	85,905,419	94,430,313	(8,524,894)
2024	86,027,330	95,435,557	(9,408,227)
2025	87,602,035	95,744,298	(8,142,263)
2026	87,976,157	96,594,919	(8,618,762)
2027	91,051,456	97,601,148	(6,549,692)
2028	87,455,638	99,209,840	(11,754,202)
2029	90,679,958	100,122,207	(9,442,249)
2030	87,330,556	100,912,249	(13,581,694)
2031	88,331,501	102,148,066	(13,816,565)
2032	85,999,274	103,926,366	(17,927,093)
2033	90,965,316	104,641,500	(13,676,184)
2034	87,611,827	105,542,792	(17,930,965)
2035	92,829,185	106,656,182	(13,826,997)
2036	92,587,585	107,698,643	(15,111,058)
2037	92,749,240	108,571,202	(15,821,962)
2038	92,911,607	109,593,016	(16,681,409)
2039	92,426,410	110,518,918	(18,092,508)
2040	91,812,715	111,554,353	(19,741,638)

SCC STAFF ANALYSIS OF CUSTOMER BILL IMPACTS OF VIRGINIA PARTICIPATING IN RGGI
February 21, 2019

EXECUTIVE SUMMARY

During the 2019 Virginia General Assembly session, bills were introduced regarding Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI). Using currently available information and applying certain assumptions, the Staff of the State Corporation Commission ("SCC") made estimates of the potential cost and rate impacts of *joining* or *linking* to RGGI. This document was prepared at the request of the Virginia Department of Environmental Quality ("DEQ") to explain the method and assumptions used by SCC Staff which produced these estimates.

Since DEQ's proposed RGGI rule envisions Virginia linking to RGGI, this document will address the implications of Virginia linking to RGGI. SCC Staff estimates the total cost to Dominion Energy Virginia ("DEV") of linking to RGGI to be about $3.3 billion. SCC Staff estimates the total cost to DEV of joining RGGI to be about $5.9 billion. SCC Staff estimates that linking to RGGI will *increase* the typical DEV ("DEV") residential customer's monthly bill by an average of $6.95 from $120.52 to $127.48 over the 25-year study period.[1]

DEQ estimates that the typical monthly bill for a residential customer served by DEV will *decrease* by an average of $0.54 over the 2020-2030 time period. Given that RGGI is a government imposed cap and trade mechanism designed to impose a carbon tax on the use of fossil fuel generation, and given that DEV owns a significant portfolio of coal and natural gas generation units, the SCC Staff finds DEQ's projection of falling customer bills to be counterintuitive.

DEQ modeled DEV as if it was solely a purchaser of electricity from the grid. In contrast, SCC Staff modeled DEV's actual market structure as a vertically integrated utility that owns fossil fuel generation resources. SCC Staff correctly modeled DEV as both a purchaser of electricity from the grid and as a seller of electricity into the grid.

Chesterfield Units 5 and 6 and Clover Units 1 and 2 are forced into retirement prematurely under SCC Staff's modeling. These units must be paid for by DEV's customers whether the units operate or not. Furthermore, as a member of the PJM Interconnection, LLC ("PJM"), DEV is required to meet PJM's capacity obligation. SCC Staff's analysis shows that approximately 1,500 MWs of capacity will have to be constructed earlier than would otherwise be the case to replace the 4 retired units. DEV's customers essentially pay twice. First, they must pay for the 4 retired units for capacity that they will no longer receive due to RGGI. Secondly, they must pay for the costs of new capacity constructed sooner than otherwise necessary to replace these retired units.

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[1] Given that SCC Staff used a 25-year study period, this should be viewed as the average increase in the typical residential customer's monthly bill (averaged over the 25-year period in constant dollars). Thus, these bill impacts will likely be lower than $6.95 in the beginning of the study period and higher than that amount at the end of the study period. Measured in future inflated dollars, these average bill impacts will likely be greater than $6.95 over the 25-year period.

SCC STAFF ANALYSIS OF CUSTOMER BILL IMPACTS OF VIRGINIA PARTICIPATING IN RGGI

February 21, 2019

Q. What is the SCC Staff's understanding of the Regional Greenhouse Gas Initiative ("RGGI")?

A. RGGI is a "cap and trade" market mechanism to cap and reduce CO_2 emissions from the electric power sector. It is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. The number of allowances, or "cap," is ratcheted down each year. Each of the RGGI member states is allocated the number of CO_2 emissions allowances corresponding to its share of the overall RGGI cap. Generally, each member state must submit its CO_2 emissions allowances for sale in the RGGI auction with the revenues received from these sales flowing back to each state. Fossil fuel electric power generators with a capacity of 25 megawatts ("MWs") or greater are required to hold allowances equal to their CO_2 emissions. The required offsetting CO_2 emissions allowances must be purchased by each fossil fuel generator. The Virginia Department of Environmental Quality ("DEQ") proposes to link to RGGI and its allowance auction system by way of a "consignment auction." Essentially, RGGI levies a carbon tax on fossil fuel generation, payable by electric generators in each RGGI state, with the goal of making fossil fuel generation less competitive, thus leading to reductions in fossil fuel generation and corresponding reductions in CO_2 emissions.

Q. What is the SCC Staff's understanding of DEQ's estimate of the bill impact on a typical residential customer under RGGI?

A. DEQ estimates that the typical monthly bill for a residential customer served by Dominion Energy Virginia ("DEV") will decrease by an average of $0.54 over the 2020-2030 time period. Given that RGGI is a government imposed cap and trade mechanism designed to impose additional costs on the use of fossil fuel generation, and given that DEV owns a significant portfolio of coal and natural gas generation units, the SCC Staff finds DEQ's projection of falling customer bills to be counterintuitive.

Q. Has the SCC Staff separately analyzed the cost and rate impacts of Virginia participating in RGGI?

A. Yes. SCC Staff estimates that RGGI will impose costs on DEV's customers. SCC Staff estimates that a typical monthly residential bill will see an average increase between $7 and $12, over the 2019-2043 time period, depending on whether Virginia *links* to RGGI or *joins* RGGI. SCC Staff estimates the total cost of linking to RGGI to be about $3.3 billion. SCC Staff estimates the total cost of joining RGGI to be about $5.9 billion.

Since DEQ's proposed RGGI rule envisions Virginia linking to RGGI, the remainder of this document will address the implications of Virginia linking to RGGI.[2]

Q. Why is the SCC Staff's bill impact of linking to RGGI higher than the bill impact calculated by DEQ?

A. As will be discussed in more detail later in this document, the most important difference between SCC Staff and DEQ is the market structure that was used in the modeling. DEQ modeled DEV as a deregulated utility and Virginia as a deregulated market. As a result, DEQ modeled DEV as if it was solely a purchaser of electricity from the grid. In contrast, SCC Staff modeled DEV's actual market structure as a vertically integrated utility that owns fossil fuel generation resources. SCC Staff correctly modeled DEV as both a purchaser of electricity from the grid and as a seller of electricity into the grid.

The deregulated market approach modeled by DEQ is consistent with the market structure that exists in all other RGGI member states except Vermont. It does not, however, reflect the market reality that exists in Virginia, and it is not appropriate to use this market structure to measure customer bill impacts of RGGI compliance for Virginians. Simply put, DEQ's model assumes that DEV does not own fossil fuel generation units that will be impacted by the new Virginia RGGI CO_2 regulations. However, DEV does own fossil fuel generation units and its customers will pay for the increased operating costs of the fossil fuel units that continue to run. Furthermore, DEV's customers will pay for these units whether the units are run or not.

[2] SCC Staff modeling assumed that if Virginia links to RGGI, 95% of the revenues received through the sale of CO_2 emissions allowances in the RGGI auctions would flow back to customers though the utilities to offset customer bill impacts. There are a variety of ways that emissions allowances revenues could serve to reduce DEV's customer bills. SCC Staff's analysis assumes that these revenues will benefit customers in one way or another.

Q. The 2018 Grid Transformation and Security Act ("2018 GTSA" or "SB966") contained several policy objectives[3] for DEV to potentially achieve by 2028 including: (1) the construction and/or purchase of 5,000 MWs of solar/wind generation capacity; (2) $870 million of proposed spending on energy efficiency programs; and (3) the construction of 30 MWs of battery storage. Will achieving these policy objectives alone result in DEV meeting its CO_2 emissions reductions targets under RGGI?

A. No. Determining the impact of 2018 GTSA policy goals must be done in the context of DEVs' membership and participation in the PJM Interconnection, LLC ("PJM") energy and capacity markets.[4]

PJM dispatches generation based on the economics of each individual unit. The addition of 5,000 MWs of solar/wind resources in Virginia, 30 MWs of battery storage, and $870 million of spending on energy efficiency will displace generation from the least efficient and highest cost generating units in the PJM footprint.[5] These units will most likely be aging coal and/or natural gas generating units. These fossil fuel generating units, while located within PJM, may or may not be in Virginia.[6] As a result, even if DEV achieves all of the 2018 GTSA's policy objectives described above, it may nevertheless be required to (i) prematurely retire currently operational coal generation units to meet RGGI CO_2 emissions reduction goals, and (ii) concurrently construct new natural gas fired generating units in order to meet its generation capacity obligation in PJM.

Q. Please provide the results of the SCC Staff's model simulations of Virginia linking to RGGI.

A. The SCC Staff's analysis[7] used the PLEXOS®[8] model to simulate several different scenarios as follows:

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[3] SB966 also included the policy goals of grid modernization, the undergrounding of transmission lines, and the undergrounding of tap lines.

[4] PJM coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. For purposes of generation unit dispatch, the utilities in these states operate together as one large utility system.

[5] Likewise, the construction of renewable facilities or the implementation of energy efficiency measures in other PJM states may lead to less CO_2 emissions in Virginia.

[6] For example, the construction of additional solar facilities in Virginia may lead to the retirement of a coal unit in West Virginia or Ohio.

[7] DEV owns the PLEXOS® software and performed the model runs contained in this document at the direction of the SCC Staff.

[8] The PLEXOS® Integrated Energy model is a power market simulation software that uses mathematical programming and stochastic optimization techniques and is widely used by electric utilities including both DEV and Appalachian Power Company in Virginia.

1. A base scenario which represents a least cost plan for DEV to meet its customers' electricity requirements and that assumes that Virginia does not participate in RGGI;

2. A GTSA scenario in which the model is required to select the 5,000 MWs of solar/wind, 30 MWs of battery storage, and $870 million of energy efficiency contained in the 2018 GTSA and which also assumes that Virginia does not participate in RGGI; and

3. A GTSA-RGGI scenario in which the model is required to select the 5,000 MWs of solar/wind, 30 MWs of battery storage, and $870 million of energy efficiency contained in the 2018 GTSA and which also assumes that Virginia links to RGGI.

The model results showing the resulting DEV generating unit build plans and the net present value ("NPV") costs under each scenario are presented below:

	Base No RGGI		GTSA No RGGI		GTSA RGGI Link	
	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs
2020	-	-	480	-	480	-
2021	80	-	491	-	491	-
2022	-	458	480	458	480	458
2023	-	458	480	458	480	458
2024	-	458	480	458	480	458
2025	-	458	480	-	480	458
2026	-	458	480	-	480	458
2027	-	458	480	-	480	458
2028	-	-	480	-	480	-
2029	-	458	480	-	480	458
2030	-	-	160	458	160	-
2031	-	-	-	-	-	-
2032	-	458	-	458	80	458
2033	-	458	-	-	480	-
Total	**80**	**4,122**	**4,971**	**2,290**	**5,531**	**3,664**
2034	480	-	-	458	-	458
2035	480	-	320	-	80	-
2036	160	-	-	458	-	458
2037	-	458	-	-	160	-
2038	160	-	-	458	-	-
2039	-	-	-	-	-	-
2040	-	458	-	458	-	-
2041	-	-	-	-	-	-
2042	-	458	-	458	-	-
2043	-	-	-	-	-	-
Total	**1,360**	**5,496**	**5,291**	**4,580**	**5,771**	**4,580**
NPV ($B)		$26.75		$27.54		$29.95

Q. What are the differences in the build plans under each scenario?

A. SCC Staff utilized a 25-year study period, which is the standard study period used by the State Corporation Commission ("Commission") to evaluate utility Integrated Resource Plans and utility applications for Certificates of Public Convenience and Necessity for the construction of utility proposed generation projects. In all three scenarios, the model selected the nuclear license extensions for the Surry and North Anna nuclear units on a cost optimization basis. All three scenarios under SCC Staff's modeling also include the retirements of all current cold reserve generating units[9] and Possum Point Unit 5. Under the GTSA-RGGI scenario, the additional retirements of Chesterfield Units 5 and 6 in 2022 and Clover Units 1 and 2 in 2025 are required as the added costs of purchasing the required offsetting CO_2 emissions allowances for these units make them uneconomic. The cost implications of these premature retirements will be discussed later in this document.

Q. Based on the SCC Staff's model results, what is the incremental cost of linking to RGGI?

A. Assuming the generation and energy efficiency related components contained in the 2018 GTSA are implemented, SCC Staff estimates that linking to RGGI will impose an incremental additional NPV cost of $2.41 billion[10] ($29.95 billion minus $27.54 billion) over the 25-year study period.

Q. How did the SCC Staff develop its estimate of a $7 typical residential customer bill impact for linking to RGGI?

A. First, SCC Staff developed a ratio of the NPV cost of the GTSA-No RGGI scenario divided by the NPV cost of the Base–No RGGI scenario. SCC Staff then applied this ratio to the base generation, generation rate adjustment clauses ("RACs"), and fuel factor portion of the current typical residential customer's monthly bill to determine the bill impact of the generation and energy efficiency-related components of the 2018 GTSA. SCC Staff estimates that the generation and energy efficiency-related components of the 2018 GTSA will increase the typical residential customer's monthly bill by $2.28 from $118.24 to $120.52.

SCC Staff then developed a ratio of the NPV cost of the GTSA-RGGI Link scenario divided by the NPV cost of the GTSA-No RGGI scenario. This ratio was applied to the

[9] The following units were placed in cold reserve status during 2018: Bellemeade 1, Bremo 3 & 4, Mecklenberg 1 & 2, Pittsylvania 1, Chesterfield 3 & 4, and Possum Point 3 & 4, representing 1,292 MW of generating capacity.
[10] This is equivalent to approximately $3.3 billion in nominal dollars.

base generation, generation RACs, and fuel factor components of the estimated typical residential customer's monthly bill described above for the generation and energy efficiency-related components 2018 GTSA. SCC Staff estimates that linking to RGGI will increase the typical residential customer's monthly bill by an average of $6.95 from $120.52 to $127.48 over the 25-year study period.[11]

Q. Identify the key assumptions the SCC Staff used in its RGGI bill analysis for DEV customers.

A. Some of the key assumptions are as follows:

- SCC Staff used a RGGI CO_2 emissions cap for Virginia of 28 million tons beginning in 2020 which decreases 3% per year through 2030, as proposed in Virginia State Air Pollution Control Board regulations currently under review.

- SCC Staff modeled DEV as the vertically integrated utility that it is, i.e., a utility that owns generation resources – and whose customers will pay for these units regardless of whether they are run or not;

- SCC Staff used the CO_2 emission containment reserve ("ECR") trigger price floor for CO_2 emission allowances published by RGGI;

- SCC Staff used a discount rate of 6.31%, which represents DEV's after tax weighted average cost of capital used in its most recent Integrated Resource Plan proceeding before the Commission; and

- SCC Staff assumed that 5,000 MWs of solar, 30 MWs of battery storage, and $870 million of spending on energy efficiency programs, consistent with the 2018 GTSA, are built or implemented.

- SCC Staff's analysis reflects the Commission's findings in its December 7, 2018 Order in Case No. PUR-2018-00065 regarding DEV's 2018 Integrated Resource Plan. Namely, Staff's analysis used: (1) the coincident peak PJM load and energy forecast scaled down to the DEV load serving entity level; and (2) a capacity factor of 23% for solar generating resources.

[11] Given that SCC Staff used a 25-year study period, this should be viewed as the average increase in the typical residential customer's monthly bill (averaged over the 25-year period in constant dollars). Thus, these bill impacts will likely be lower than $6.95 in the beginning of the study period and higher than that amount at the end of the study period. Measured in future inflated dollars, these average bill impacts will likely be greater than $6.95 over the 25-year period.

Q. Why is the SCC Staff's bill impact of participating in RGGI higher than the bill impact calculated by DEQ?

A. SCC Staff's customer bill impacts showing an increase to customer bills significantly differs from DEQ's estimates of RGGI compliance resulting in lower customer bills. This is due to differing modeling assumptions. Some of DEQ's key assumptions are as follows:

- DEQ modeled DEV as if it were a deregulated utility that does not own generation resources operating in a deregulated competitive energy market. Thus, DEQ omitted the customer bill impact of increased fuel costs and prematurely retiring generating units and of additional costs to operate DEV's fossil fuel generating units that continue to run;

- DEQ used CO_2 emission allowance prices that are lower than the ECR trigger price for carbon emission allowances published by RGGI;

- DEQ used a discount rate of 2.1%;

- DEQ assumed that the generation and energy efficiency-related policy objectives contained in the 2018 GTSA are implemented.

The impact of these key DEQ assumptions is discussed below.

Q. What is the practical effect of DEQ using a CO_2 emission allowance price that is lower than the RGGI ECR trigger price floor for carbon emission allowances published by RGGI?

A. To the extent that the carbon emission allowance prices are lower, this will result in a lower cost estimate for RGGI compliance and lower typical bill impacts. A comparison of DEQ's CO_2 emission allowance prices, the RGGI ECR trigger price floor, and the RGGI CO_2 cost containment reserve ("CCR") trigger price ceiling is shown below.

	RGGI ECR Trigger Price Floor	RGGI CCR Trigger Price Ceiling	DEQ Price
2020	$6.00	$10.77	N/A
2021	$6.00	$13.00	N/A
2022	$6.42	$13.91	$4.01
2023	$6.87	$14.88	N/A
2024	$7.35	$15.92	N/A
2025	$7.86	$17.03	$4.55
2026	$8.41	$18.22	N/A
2027	$9.00	$19.50	N/A
2028	$9.63	$20.87	$5.18
2029	$10.30	$22.33	N/A
2030	$11.02	$23.89	$5.65

Q. Please explain why SCC Staff views the RGGI ECR trigger price as a floor and the RGGI CCR trigger price as a ceiling.

A. The RGGI ECR and CCR trigger prices establish a range of CO_2 emissions allowance prices which represent the policy goals of RGGI. These trigger prices should be viewed as a "soft" price floor and a "soft" price ceiling. Actual prices for CO_2 emissions allowances can clear at a price below the ECR trigger price or above the CCR trigger price in any given year. However, if the auction price clears below the ECR trigger price, RGGI will remove CO_2 emissions allowances from future auctions to force prices back above the ECR trigger price floor. Similarly, if the auction price clears above the CCR trigger price, then RGGI would inject additional CO_2 emissions allowances into the market to force prices back below the CCR trigger price ceiling.

Q. Does the SCC Staff view DEQ's assumed CO_2 emissions allowance prices to be too low?

A. Not necessarily. Historically, CO_2 emissions allowances have cleared the RGGI auction at relatively low prices. DEQ is assuming that this will continue to be the case in the future. In addition, as mentioned above, the RGGI market can clear at a price below the ECR trigger price. However, when estimating the costs of RGGI compliance going forward for Virginia, SCC Staff believes it is more realistic to use CO_2 emissions allowance prices that

are consistent with RGGI's allowance price trigger mechanisms described above. SCC Staff used the ECR trigger price floor which SCC Staff views as being a conservative assumption.

Q. What is the practical effect of DEQ using a discount rate lower than DEV's weighted average cost of capital?

A. Using a lower discount rate understates the true costs of future capital investments. The Commission has consistently used DEV's weighted average cost of capital in evaluating CPCN applications for proposed generation and transmission projects. This is appropriate because it reflects DEV's actual costs of raising capital for these large capital projects.

Q. What is the practical effect of DEQ modeling DEV as if it were a deregulated utility that does not own generation resources operating in a deregulated competitive energy market?

A. Virginia is unique compared to the RGGI member states which are fully deregulated. Local Distribution Companies ("LDCs") in those deregulated states do not own generation assets. All generation is provided by merchant generators selling into the grid. All power consumed by the LDCs is purchased from the grid or through bilateral power purchase agreements with merchant generators.

In contrast, DEV is a vertically integrated utility that owns generation, transmission, and distribution resources. The LDCs in other RGGI states are purchasers of electricity from the grid. DEV is both a purchaser of electricity from the grid and a producer of electricity sold into the grid. DEV's ownership of generation resources is a key factor that must be considered in any RGGI analysis and it appears that DEQ did not fully consider this factor.

Q. Focusing on the impacts of RGGI on DEV as a purchaser of electricity, explain how DEQ calculated customer bill impacts.

A. DEQ calculates the incremental increase of PJM Interconnection, LLC ("PJM") power prices assuming that Virginia links to RGGI. DEQ then multiplies this incremental increase in cost per kilowatt-hour ("kWh") by the average monthly bill usage to arrive at the bill increase cost of RGGI compliance. DEQ then adjusts this bill impact by subtracting the expected pro-rata share of the RGGI CO_2 emissions allowance revenues that DEV will receive from the sale of CO_2 emissions allowances in the RGGI auction. It appears that DEQ's estimate of RGGI CO_2 emissions allowance revenues is greater than the increase in PJM power prices which results in DEQ's estimate of falling customer bills under RGGI.

Q. Does the SCC Staff agree that Virginia linking to RGGI will put upward pressure on PJM energy prices?

A. Yes. SCC Staff estimates that Virginia linking to RGGI will cause PJM power prices to increase by an average of $0.44 per megawatt hour ("MWh") over the 2020 to 2030 time period. Hourly PJM energy prices are determined by the marginal unit that clears the market each hour. The imposition of additional costs on Virginia fossil fuel units for the required offsetting CO_2 emissions allowances under RGGI will generally lead to higher cost marginal units setting the hourly PJM energy price, thus putting upward pressure on PJM energy prices.

Q. Does the SCC Staff agree that Virginia linking to RGGI will result in DEV receiving revenues from the sale of CO_2 emissions allowances into the RGGI auctions?

A. Yes, the table below shows SCC Staff's estimate of expected revenues from the sale of CO_2 emissions allowances. SCC Staff assumed that DEV would be allocated 70% of the Virginia total. SCC Staff further assumed that 5% of this total would go to the Virginia Department of Mines, Minerals and Energy ("DMME").[12]

[12] 5% of the revenues will go to DMME to defray the costs of oversight and implementation of Virginia's participation in RGGI.

	VA RGGI Carbon Cap (tons) (a)	DEV Carbon Cap 70% of VA (b)	DEV Cap @ 95% (tons) (c)	RGGI ECR Prices (d)	RGGI Allowance Revenues (e) = (c) x (d)
2020	28,000,000	19,600,000	18,620,000	$6.00	$111,720,000
2021	27,160,000	19,012,000	18,061,400	$6.00	$108,368,400
2022	26,320,000	18,424,000	17,502,800	$6.42	$112,367,976
2023	25,480,000	17,836,000	16,944,200	$6.87	$116,406,654
2024	24,640,000	17,248,000	16,385,600	$7.35	$120,434,160
2025	23,800,000	16,660,000	15,827,000	$7.86	$124,400,220
2026	22,960,000	16,072,000	15,268,400	$8.41	$128,407,244
2027	22,120,000	15,484,000	14,709,800	$9.00	$132,388,200
2028	21,280,000	14,896,000	14,151,200	$9.63	$136,276,056
2029	20,440,000	14,308,000	13,592,600	$10.30	$140,003,780
2030	19,600,000	13,720,000	13,034,000	$11.02	$143,634,680

Q. What is missing from DEQ's RGGI cost analysis?

A. As mentioned earlier, SCC Staff modeled DEV as a vertically integrated utility that owns a portfolio of fossil fuel generation resources. DEV is both a purchaser of power from the PJM market and a seller of power into the PJM market. DEQ's RGGI cost analysis does not include the costs of the CO_2 emissions allowances that DEV must purchase for each of its fossil fuel units. These costs will flow back to customers and increase customer bills. The cost of CO_2 emissions allowances will impact customers in two different ways.

First, many of DEV's fossil fuel units will continue to clear the PJM energy and capacity markets and will continue to run. However, given that these units will now have a higher unit dispatch cost, these units will return far less value back to the customer through the fuel factor.[13]

Secondly, Chesterfield Units 5 and 6 and Clover Units 1 and 2 are forced into retirement prematurely under SCC Staff's modeling. These units must be paid for by DEV's customers whether the units run or not.

[13] For a hypothetical example, if the unit dispatch cost for a fossil fuel unit is $30/MWh without RGGI and the PJM energy price is $33/MWh, then this unit will provide $3/MWh of value back to DEV's customers for every MWh sold into PJM. If the unit dispatch cost is increased to $32.50/MWh under RGGI reflecting the costs to the utility of the required offsetting CO_2 emissions allowances, then this unit will still run but it will now only provide $0.50/MWh of value back to the customer. The DEV fuel factor will increase to recover the $2.50/MWh of required RGGI costs under this hypothetical example.

Q. Why must customers pay for these prematurely retired units?

A. As a regulated utility, DEV has a legal obligation to provide service to every customer in its service area. When these units were approved for construction, they formed a necessary part of the generation "fleet" used to supply power to customers; thus, under the regulatory framework, the utility is entitled to recover the entire cost.

Q. What happens to the unrecovered costs of prematurely retired units in DEQ's analysis?

A. DEQ treated all generation units as merchant generators. As such, the shareholders of the entities that own the retiring fossil fuel unit would bear these unrecovered costs. Similarly, even for fossil fuel units that continue to run, DEQ's analysis assumes that the cost of the required offsetting CO_2 emissions allowances will be borne by the shareholders of the entities that own the affected fossil fuel generating units. That is, DEQ assumes that these shareholders will earn a lower profit as a result. In reality, since DEV owns the fossil fuel generating units, the cost of the required offsetting CO_2 emissions allowances will be collected from DEV's customers most likely through a higher fuel factor than would otherwise be the case.

Q. What are the costs that DEV will incur under RGGI for its fossil fuel units that will continue to run under RGGI?

A. SCC Staff estimated these costs to be the product of the expected CO_2 emissions (tons) for the GTSA-RGGI Link scenario and the ECR trigger price. This is presented in the table below.

	RGGI ECR Prices	RGGI/GTSA DEV Carbon Output (tons)	RGGI Allowance Costs
	(a)	(b)	(c) = (a) x (b)
2020	$6.00	26,488,641	158,931,846
2021	$6.00	25,240,860	151,445,160
2022	$6.42	25,715,612	165,094,229
2023	$6.87	25,617,605	175,992,946
2024	$7.35	24,970,901	183,536,122
2025	$7.86	24,767,813	194,675,010
2026	$8.41	24,441,398	205,552,157
2027	$9.00	26,013,263	234,119,367
2028	$9.63	22,956,099	221,067,233
2029	$10.30	24,424,271	251,569,991
2030	$11.02	22,877,523	252,110,303

Q. How would including the costs of CO_2 emissions allowances for DEV's fossil fuel units that will continue to run impact DEQ's RGGI cost analysis?

A. This is displayed in the table below.

	DEV Energy Consumed (MWh)	RGGI PJM Energy Price Increase ($/MWh)	Increased Cost of Purchased Energy	DEV RGGI Allowance Revenues	DEQ RGGI Cost Analysis	DEV RGGI Allowance Costs	SCC Staff RGGI Cost Analysis
	(a)	(b)	(c) = (a) x (b)	(d)	(e) = (c) - (d)	(f)	(g) = (c) - (d) + (f)
2020	88,217,000	$0.44	$38,534,790	$111,720,000	($73,185,210)	$158,931,846	$85,746,636
2021	88,602,520	$0.44	$38,703,192	$108,368,400	($69,665,208)	$151,445,160	$81,779,952
2022	89,374,730	$0.44	$39,040,507	$112,367,976	($73,327,469)	$165,094,229	$91,766,760
2023	89,917,040	$0.44	$39,277,398	$116,406,654	($77,129,256)	$175,992,946	$98,863,690
2024	90,556,640	$0.44	$39,556,787	$120,434,160	($80,877,373)	$183,536,122	$102,658,749
2025	90,793,260	$0.44	$39,660,147	$124,400,220	($84,740,073)	$194,675,010	$109,934,937
2026	91,353,920	$0.44	$39,905,053	$128,407,244	($88,502,191)	$205,552,157	$117,049,966
2027	92,017,840	$0.44	$40,195,066	$132,388,200	($92,193,134)	$234,119,367	$141,926,233
2028	93,082,110	$0.44	$40,659,958	$136,276,056	($95,616,098)	$221,067,233	$125,451,135
2029	94,001,280	$0.44	$41,061,468	$140,003,780	($98,942,312)	$251,569,991	$152,627,680
2030	94,927,940	$0.44	$41,466,250	$143,634,680	($102,168,430)	$252,110,303	$149,941,874

The table above is based on SCC Staff's RGGI model outputs for the GTSA-RGGI Link scenario. Applying DEQ's methodology shows a net cost reduction as the revenues received from the sale of CO_2 emissions allowances is greater than the increased cost of purchased power in all years. However, DEQ's methodology fails to include the required purchases of CO_2 emissions allowances to cover the CO_2 emissions from DEV's fossil fuel units that continue to run. SCC Staff's methodology includes those costs and results in a net cost increase in all years. The costs of the required CO_2 emissions allowances will increase the dispatch costs of DEV's fossil fuel units, which will cause these units to provide less value back to DEV's customers. This will be seen on customers' bills as an increase in the fuel factor. This increase in the fuel factor is captured in the SCC Staff's estimate of a $6.95 increase in the typical residential customer's bill.

It should be noted that DEQ's analysis stops at 2030 (11 years). However, RGGI will continue to impose costs beyond 2030. SCC Staff's analysis includes the costs of RGGI compliance over a 25-year study period, as discussed above.

It is important to note that the table above does not include the costs associated with DEV's fossil fuel units that are forced to retire prematurely nor the increased fuel costs from dispatch changes.

Q. What additional costs are imposed on DEV's customers from Chesterfield Units 5 and 6 and Clover Units 1 and 2 retiring prematurely?

A. SCC Staff's RGGI analysis shows that Chesterfield Units 5 and 6 and Clover Units 1 and 2 are forced into early retirement in 2022 and 2025, respectively. These 4 units have a combined capacity of nearly 1,500 MWs. These units are forced into retirement prematurely because the increase in their dispatch costs from including the costs of CO_2 emissions allowances under RGGI make them no longer competitive in the PJM power market.

Chesterfield Units 5 and 6 would retire in 2034 and 2039, respectively, without RGGI. Likewise, Clover Units 1 and 2 would retire in 2050 and 2051, respectively, without RGGI. Thus, RGGI will result in these units retiring between 12 and 26 years early.

The combined end of year 2018 net book value for DEV of these 4 units is $781 million.[14] The entire $781 million will be collected from DEV's customers.[15]

Furthermore, as a member of PJM, DEV is required to meet PJM's capacity obligation. SCC Staff's analysis shows that approximately 1,500 MWs of capacity will have to be constructed earlier than would otherwise be the case to replace the 4 retired units. Under the SCC Staff's modeling results, most of this will be natural gas-powered combustion turbine units (1,376 MWs), with the remainder being additional solar units (560 MWs nameplate).[16] SCC Staff estimates that this replacement capacity will cost approximately $1.3 billion, excluding financing costs and a profit margin. This investment will also be collected from DEV's customers.

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[14] Chesterfield Units 5 and 6 have a net book value of $626,986,555. Clover Units 1 and 2 have a net book value of $307,710,398. DEV has a 50% ownership in Clover Units 1 and 2. The remaining 50%, or $153,855,199, is owned by ODEC. SCC Staff has not performed an analysis of the customer bill impacts on Electric Cooperative customers in Virginia due to the premature retirement of Clover Units 1 and 2.

[15] In addition, there are lost property taxes and lost jobs implications associated with these 4 units retiring prematurely. SCC Staff's analysis did not attempt to capture or quantify these impacts.

[16] 560 MWs of nameplate solar capacity translates into about 129 MWs for purposes of meeting the PJM capacity obligation.

DEV's customers essentially pay twice. First, they must pay for the capacity of the retired units for capacity that they will no longer receive due to RGGI. Secondly, they must pay for the costs of new capacity constructed sooner than otherwise necessary to replace these retired units.

The costs of the units required to replace the capacity of the prematurely retired units will most likely be recovered through future RAC's. These bill impacts of these new RACs are captured in the SCC Staff's estimate of a $6.95 increase in the typical residential customer's bill.

ATTACHMENT C

VIRGINIA CECFPA

VIRGINIA ACTS OF ASSEMBLY -- 2020 RECONVENED SESSION

CHAPTER 1280

An Act to amend and reenact §§ 10.1-603.24 and 10.1-603.25 of the Code of Virginia and to amend the Code of Virginia by adding in Chapter 13 of Title 10.1 an article numbered 4, consisting of sections numbered 10.1-1329, 10.1-1330, and 10.1-1331, relating to Clean Energy and Community Flood Preparedness Act; fund.

[S 1027]

Approved April 22, 2020

Be it enacted by the General Assembly of Virginia:

1. That §§ 10.1-603.24 and 10.1-603.25 of the Code of Virginia are amended and reenacted and that the Code of Virginia is amended by adding in Chapter 13 of Title 10.1 an article numbered 4, consisting of sections numbered 10.1-1329, 10.1-1330, and 10.1-1331, as follows:

Article 1.3.

Virginia ~~Shoreline Resiliency~~ *Community Flood Preparedness* Fund.

§ 10.1-603.24. Definitions.

As used in this article, unless the context requires a different meaning:

"Authority" means the Virginia Resources Authority.

"Cost," as applied to any project financed under the provisions of this article, means the total of all costs incurred by the local government as reasonable and necessary for carrying out all works and undertakings necessary or incident to the accomplishment of any project.

"Department" means the Virginia Department of ~~Emergency Management~~ *Conservation and Recreation.*

"Flood prevention or protection" means the construction of hazard mitigation projects, acquisition of land, or implementation of land use controls that reduce or mitigate damage from coastal or riverine flooding.

"Flood prevention or protection study" means the conduct of a hydraulic or hydrologic study of a flood plain with historic and predicted floods, the assessment of flood risk, and the development of strategies to prevent or mitigate damage from coastal or riverine flooding.

"Fund" means the Virginia ~~Shoreline Resiliency~~ *Community Flood Preparedness* Fund *created pursuant to § 10.1-603.25.*

"Local government" means any county, city, town, municipal corporation, authority, district, commission, or political subdivision created by the General Assembly or pursuant to the Constitution of Virginia or laws of the Commonwealth.

"Low-income geographic area" means any locality, or community within a locality, that has a median household income that is not greater than 80 percent of the local median household income, or any area in the Commonwealth designated as a qualified opportunity zone by the U.S. Secretary of the Treasury via his delegation of authority to the Internal Revenue Service.

"Nature-based solution" means an approach that reduces the impacts of flood and storm events through the use of environmental processes and natural systems. A nature-based solution may provide additional benefits beyond flood control, including recreational opportunities and improved water quality.

§ 10.1-603.25. Virginia Community Flood Preparedness Fund; loan and grant program.

~~There shall be set apart a permanent and perpetual fund, to be known as the~~ *A. The* Virginia Shoreline Resiliency Fund~~, consisting of such~~ *is hereby continued as a permanent and perpetual fund to be known as the Virginia Community Flood Preparedness Fund. All sums that are designated for deposit in the Fund from revenue generated by the sale of emissions allowances pursuant to subdivision C 1 of § 10.1-1330, all* sums that may be appropriated to the Fund by the General Assembly, all receipts by the Fund from *the repayment of* loans made by it to local governments, all income from the investment of moneys held in the Fund, and any other sums designated for deposit to the Fund from any source, public or private, *including any federal grants and awards or other forms of assistance received by the Commonwealth that are eligible for deposit in the Fund under federal law, shall be designated for deposit to the Fund. Interest earned on moneys in the Fund shall remain in the Fund and be credited to it. Any moneys remaining in the Fund, including any appropriated funds and all principal, interest accrued, and payments, at the end of each fiscal year shall not revert to the general fund but shall remain in the Fund. All loans and grants provided under this article shall be deemed to promote the public purposes of enhancing flood prevention or protection and coastal resilience.* ~~The Fund shall be administered by the Department as prescribed in this article. The Department shall establish guidelines regarding the distribution of loans from the Fund and prioritization of such loans.~~

B. Moneys in the Fund shall be used solely for the purposes of enhancing flood prevention or

protection and coastal resilience as required by this article. The Authority shall manage the Fund and shall establish interest rates and repayment terms of such loans as provided in this article *in accordance with a memorandum of agreement with the Department.* The Authority may disburse from the Fund its reasonable costs and expenses incurred in the management of the Fund. *The Department shall direct distribution of loans and grants from the Fund in accordance with the provisions of subsection D.*

C. The Authority is authorized at any time and from time to time to pledge, assign, or transfer from the Fund or any bank or trust company designated by the Authority any or all of the assets of the Fund to be held in trust as security for the payment of principal of, premium, if any, and interest on any and all bonds, as defined in § 62.1-199, issued to finance any flood prevention or protection project undertaken pursuant to the provisions of this article. In addition, the Authority is authorized at any time and from time to time to sell upon such terms and conditions as the Authority deems appropriate any loan or interest thereon made pursuant to this article. The net proceeds of the sale remaining after payment of costs and expenses shall be designated for deposit to, and become part of, the Fund.

D. The Fund shall be administered by the Department as prescribed in this article. The Department, in consultation with the Secretary of Natural Resources and the Special Assistant to the Governor for Coastal Adaptation and Protection, shall establish guidelines regarding the distribution and prioritization of loans and grants, including loans and grants that support flood prevention or protection studies of statewide or regional significance.

E. Localities shall use moneys from the Fund primarily for the purpose of ~~creating a low-interest loan program to help residents and businesses~~ *implementing flood prevention and protection projects and studies in areas* that are subject to recurrent flooding as confirmed by a locality-certified floodplain manager. Moneys in the Fund may be used to mitigate future flood damage *and to assist inland and coastal communities across the Commonwealth that are subject to recurrent or repetitive flooding. No less than 25 percent of the moneys disbursed from the Fund each year shall be used for projects in low-income geographic areas. Priority shall be given to projects that implement community-scale hazard mitigation activities that use nature-based solutions to reduce flood risk.*

F. Any locality is authorized to secure a loan made ~~through such a low-interest loan program~~ *pursuant to this section* by placing a lien up to the value of the loan against any property that benefits from the loan. Such a lien shall be subordinate to each prior lien on such property, except prior liens for which the prior lienholder executes a written subordination agreement, in a form and substance acceptable to the prior lienholder in its sole and exclusive discretion, that is recorded in the land records where the property is located.

G. Any locality using moneys in the Fund to provide a loan for a project in a low-income geographic area is authorized to forgive the principal of such loan. If a locality forgives the principal of any such loan, any obligation of the locality to repay that principal to the Commonwealth shall not be forgiven and such obligation shall remain in full force and effect. The total amount of loans forgiven by all localities in a fiscal year shall not exceed 30 percent of the amount appropriated in such fiscal year to the Fund by the General Assembly.

Article 4.

Clean Energy and Community Flood Preparedness Act.

§ 10.1-1329. Definitions.

As used in this article, unless the context requires a different meaning:

"Allowance" means an authorization to emit a fixed amount of carbon dioxide.

"Allowance auction" means an auction in which the Department or its agent offers allowances for sale.

"DHCD" means the Department of Housing and Community Development.

"DMME" means the Department of Mines, Minerals and Energy.

"Energy efficiency program" has the same meaning as provided in § 56-576.

"Fund" means the Virginia Community Flood Preparedness Fund created pursuant to § 10.1-603.25.

"Housing development" means the same as that term is defined in § 36-141.

"Regional Greenhouse Gas Initiative" or "RGGI" means the program to implement the memorandum of understanding between signatory states dated December 20, 2005, and as may be amended, and the corresponding model rule that established a regional carbon dioxide electric power sector cap and trade program.

"Secretary" means the Secretary of Natural Resources.

§ 10.1-1330. Clean Energy and Community Flood Preparedness.

A. The provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et seq.).

B. The Director is hereby authorized to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article. The Director shall seek to sell 100 percent of all allowances issued each year through the allowance auction, unless the Department finds that doing so will have a negative impact on the value of

allowances and result in a net loss of consumer benefit or is otherwise inconsistent with the RGGI program.

C. To the extent permitted by Article X, Section 7 of the Constitution of Virginia, the state treasury shall (i) hold the proceeds recovered from the allowance auction in an interest-bearing account with all interest directed to the account to carry out the purposes of this article and (ii) use the proceeds without further appropriation for the following purposes:

1. Forty-five percent of the revenue shall be credited to the account established pursuant to the Fund for the purpose of assisting localities and their residents affected by recurrent flooding, sea level rise, and flooding from severe weather events.

2. Fifty percent of the revenue shall be credited to an account administered by DHCD to support low-income energy efficiency programs, including programs for eligible housing developments. DHCD shall review and approve funding proposals for such energy efficiency programs, and DMME shall provide technical assistance upon request. Any sums remaining within the account administered by DHCD, including interest thereon, at the end of each fiscal year shall not revert to the general fund but shall remain in such account to support low-income energy efficiency programs.

3. Three percent of the revenue shall be used to (i) cover reasonable administrative expenses of the Department in the administration of the revenue allocation, carbon dioxide emissions cap and trade program, and auction and (ii) carry out statewide climate change planning and mitigation activities.

4. Two percent of the revenue shall be used by DHCD, in partnership with DMME, to administer and implement low-income energy efficiency programs pursuant to subdivision 2.

D. The Department, the Department of Conservation and Recreation, DHCD, and DMME shall prepare a joint annual written report describing the Commonwealth's participation in RGGI, the annual reduction in greenhouse gas emissions, the revenues collected and deposited in the interest-bearing account maintained by the Department pursuant to this article, and a description of each way in which money was expended during the fiscal year. The report shall be submitted to the Governor and General Assembly by January 1, 2022, and annually thereafter.

§ 10.1-1331. Energy conversion or energy tolling agreements.

If the Governor seeks to include the Commonwealth as a full participant in RGGI or another carbon trading program with an open auction of allowances, or if the Department implements the final carbon trading regulation as approved by the Board on April 19, 2019, (the Final Regulation) in order to establish a carbon dioxide cap and trade program that limits and reduces the total carbon dioxide emissions released by certain electric generation facilities and that complies with the RGGI model rule, then (i) the definition of the term "life-of-the-unit contractual arrangement" under the Final Regulation shall include any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO2 budget source or CO2 budget unit and is entitled to receive all of the nameplate capacity and associated energy generated by such source or unit for the entire contractual period and (ii) any purchaser under an energy conversion or energy tolling agreement shall be responsible for acquiring any CO2 allowances required under the Final Regulation in relation to a CO2 budget source or CO2 budget unit that is subject to such agreement.

2. That the costs of allowances purchased through a market-based trading program consistent with the provisions of Article 4 (§ 10.1-1329 et seq.) of Chapter 13 of Title 10.1 of the Code of Virginia as added by this act are deemed to constitute environmental compliance project costs that may be recovered by a Phase I Utility or Phase II Utility, as defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, pursuant to subdivision A 5 e of § 56-585.1 of the Code of Virginia.

3. That any moneys in the Virginia Shoreline Resiliency Fund as created by Chapter 762 of the Acts of Assembly of 2016 shall remain in the Virginia Community Flood Preparedness Fund pursuant to § 10.1-603.25 of the Code of Virginia, as amended and reenacted by this act.

ATTACHMENT D

MEMO FROM GRAY O'DWYER

MEMORANDUM

FROM: Gray O'Dwyer
Assistant Attorney General

DATE: July 09, 2020

RE: Proposed Exempt Regulations - 9 Va. Admin. Code §§ 5-140 *et seq.*

Please note that this memorandum does not constitute an opinion, formal or informal, of the Attorney General. Rather, this memorandum contains the legal analysis of the individual staff member providing it.

It is my view that the Department of Environmental Quality ("Department") on behalf of the Virginia Air Pollution Control Board ("Board") has the authority to promulgate these proposed amendments to its regulations in 9 Va. Admin. Code §§ 5-140 *et seq.*

It is also my view that this regulation is exempted from the Virginia Administrative Process Act, §§ 2.2-4000 *et seq.*, by its enabling legislation. Chapter 1219 of the 2020 Acts of Assembly amended the Air Pollution Control Law to add a new Article 4, the Clean Energy and Community Flood Preparedness Act. Under § 10.1-1330 A, Clean Energy and Community Flood Preparedness, "[T]he provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et seq.)."

The foregoing conclusion is my own. It does not constitute an opinion, formal or informal, of the Attorney General.

ATTACHMENT E

FORM EIA 861

U.S. Energy Information Administration
Form EIA-861 – Annual Electric Power Industry Report

Table 3. Top five retailers of electricity, with end use sectors, 2018
Virginia

megawatthours

	Entity	Type of provider	All sectors	Residential	Commercial	Industrial	Transportation
1	Virginia Electric & Power Co	Investor-owned	80,672,908	30,437,245	43,060,987	6,976,081	198,595
2	Appalachian Power Co	Investor-owned	15,389,078	6,474,270	3,949,274	4,965,534	0
3	Northern Virginia Elec Coop	Cooperative	5,353,220	2,312,072	1,096,707	1,944,441	0
4	Rappahannock Electric Coop	Cooperative	3,934,308	2,373,414	355,922	1,204,972	0
5	Shenandoah Valley Elec Coop	Cooperative	2,480,862	1,201,052	517,732	762,078	0
	Total sales, top five providers		107,830,376	42,798,053	48,980,622	15,853,106	198,595
	Percent of total state sales		91	89	94	99	100

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

ATTACHMENT F

VIRGINIA ELECTRIC AND POWER COMPANY'S REPORT OF ITS INTEGRATED RESOURCE PLAN MAY 1, 2020

Dominion Energy®

Virginia Electric and Power Company's Report of Its Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Case No. PUR-2020-00035
Docket No. E-100, Sub 165

Filed: May 1, 2020

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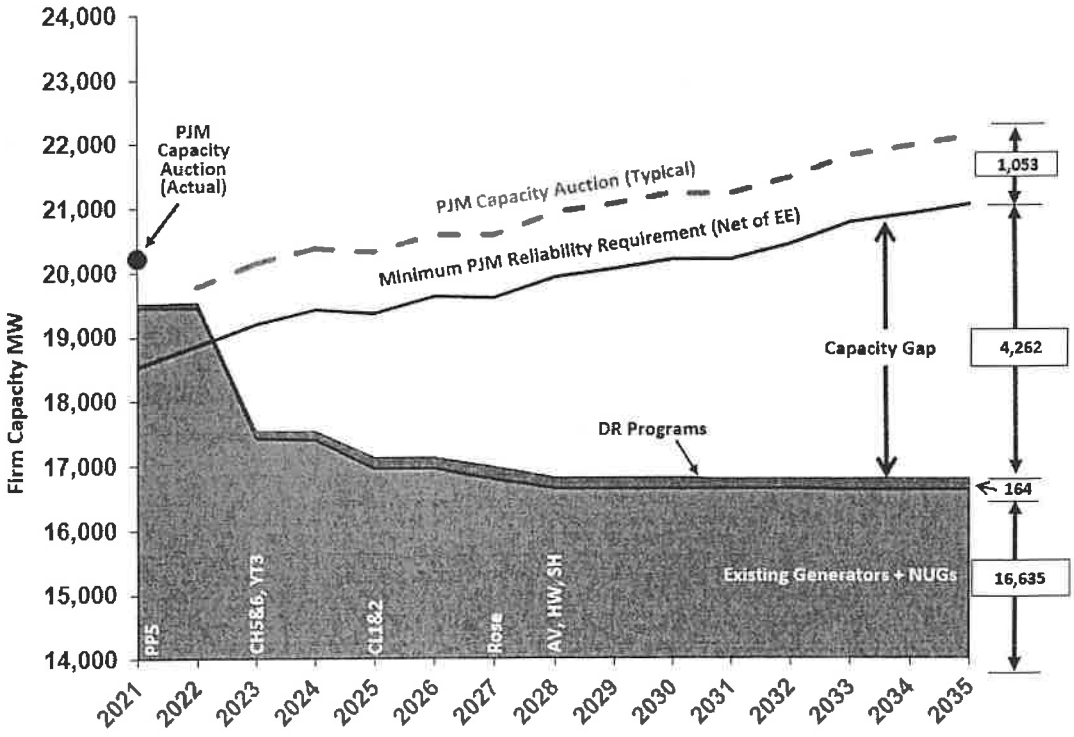
Chapter 2: Results of Integrated Planning Process

This chapter presents the results of the integrated planning process, including the Company's current capacity and energy positions, the Alternative Plans presented to meet the future capacity and energy needs of the Company's customers, and the net present value ("NPV") of each Alternative Plan. This section also includes the results of the initial transmission system reliability analysis related to the retirement of all Company-owned carbon-emitting generation in 2045, and the results of a Virginia residential bill analysis.

2.1 Capacity and Energy Positions

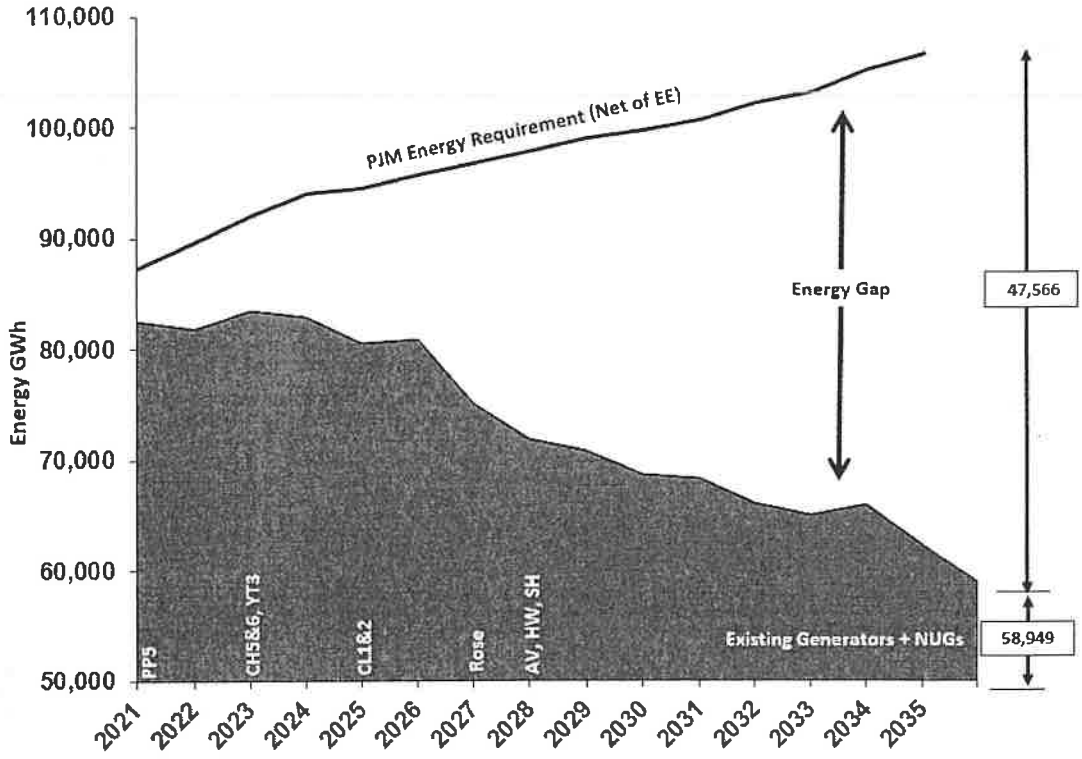
Figures 2.1.1 and 2.1.2 illustrate the Company's current capacity and energy positions using unit retirement assumptions for Alternative Plan B. After adjusting for energy efficiency, voltage optimization, and retail choice as discussed in Sections 4.1.3, 4.1.4, and 4.1.5, respectively, DOM LSE is expected to experience a compound annual growth rate ("CAGR") of 1.0% in future summer peak demand and 1.3% in energy requirements over the Planning Period.

Figure 2.1.1 - Current Company Capacity Position (2021 to 2035)



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.1.2 - Current Company Energy Position (2021 to 2035)



Notes: "Existing Generators + NUGS" include generation under construction; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

2.2 Alternative Plans

The 2020 Plan presents a range of alternatives representing paths forward for the Company to meet the future capacity and energy needs of its customers. Notably, however, the build plans shown in Alternative Plans B through D do not fully account for possible system reliability and security issues. More planning work is necessary to test the grid under different conditions to ensure system reliability and security in the long term.

The Company's options for meeting customers' future capacity and energy needs are: (i) supply-side resources, (ii) demand-side resources, and (iii) market purchases. A balanced approach—which includes the consideration of options for maintaining and enhancing rate stability, increasing energy independence, promoting economic development, incorporating input from stakeholders, and minimizing adverse environmental impact—will help the Company meet growing demand and achieve its clean energy goals while protecting customers from a variety of potential challenges.

Specifically, the Company presents four different Alternative Plans designed to meet customers' needs in the future under different scenarios, which were designed using constraint-based least-cost planning techniques:

- Plan A – This Alternative Plan presents a least-cost plan that estimates future generation expansion where there are no new constraints, including no new regulations or restrictions on CO_2 emissions. Plan A is presented for cost comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, this Alternative Plan does not represent a realistic state of relevant law and regulation.

- Plan B – This Alternative Plan sets the Company on a trajectory toward dramatically reducing greenhouse gas emissions, taking into consideration future challenges and uncertainties. Plan B includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues.

- Plan C – This Alternative Plan uses similar assumptions as Plan B, but retires all Company-owned carbon-emitting generation in 2045, resulting in close to zero CO_2 emissions from the Company's fleet in 2045. To reach zero CO_2 emissions in 2045, Plan C significantly increases the amount of energy storage resources and the level of imported power.

- Plan D – This Alternative Plan uses similar assumptions as Plan C, but changes the capacity factor assumption for future solar resources from 25% to 19%. As a result, Plan D significantly increases the amount of solar resources needed to reach zero CO_2 emissions in 2045.

Figures 2.2.1 through 2.2.4 show the build plans for each Alternative Plan. See Appendix 2A for the capacity and energy associated with all Alternative Plans.

Figure 2.2.1 - Alternative Plan A (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired	Nuclear	Retirements
2021									PP5
2022		480							
2023		480					485		YT3, CH5&6
2024		480					485		
2025		480					485		CL1&2
2026		480					485		
2027		480							Rosemary
2028		480							
2029		480							
2030		480							
2031		480							
2032		480						Surry 1	
2033		480						Surry 2	
2034		480							
2035		480							
TOTAL	0	6,720	0	0	0	0	1,940	1,676	3,030

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal).

Figure 2.2.2 - Alternative Plan B (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	600	360	220	852	400				
2027	600	360		1,704	500				Rosemary
2028	600	480	220						AV, HW, SH
2029	960	480			500				
2030	960	360	220			300			
2031	720	360							
2032	720	360			500			Surry 1	
2033	720	360						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	9,660	5,160	1,100	5,112	2,414	300	970	1,676	3,183

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.2.3 - Alternative Plan C (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	600	360	220	852	400				
2027	600	360		1,704	500				Rosemary
2028	600	480	220						AV, HW, SH
2029	960	480			500				
2030	960	360	220			300			
2031	720	360							
2032	720	360			500			Surry 1	
2033	720	360						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	9,660	5,160	1,100	5,112	2,414	300	970	1,676	3,183

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.2.4 - Alternative Plan D (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	960	360	220	852	400				
2027	960	480		1,704	500				Rosemary
2028	960	480	220						AV, HW, SH
2029	960	480			500				
2030	960	600	220			300			
2031	960	600							
2032	960	600			500			Surry 1	
2033	960	600						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	11,460	6,240	1,100	5,112	2,414	300	970	1,676	3,183

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Alternative Plans B, C, and D include 970 MW of natural gas-fired CTs as a placeholder to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

Figure 2.2.5 shows the CO_2 emissions from the Company's fleet for each Alternative Plan, while Figure 2.2.6 shows the regional CO_2 emissions for each Alternative Plan. Because the regional CO_2 emissions capture the effects of both energy imports and exports required to meet customer needs, the regional emissions are a better indicator of customers' impact on the environment.

Figure 2.2.5 – Virginia CO_2 Output from Company Fleet for Alternative Plans

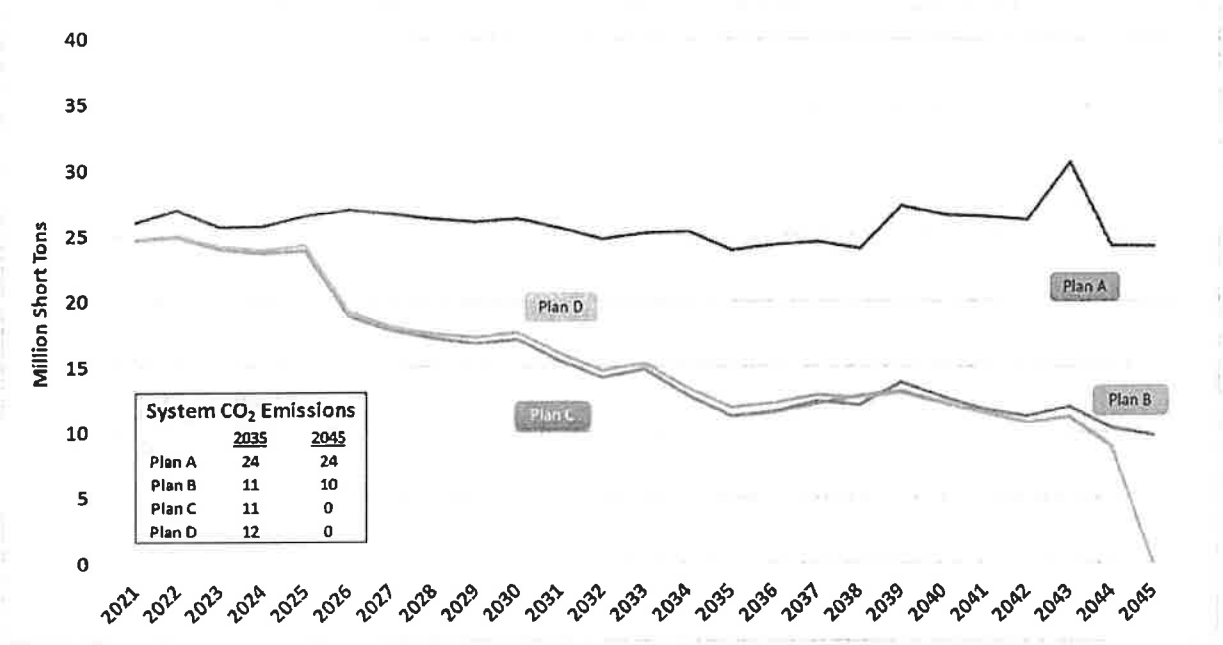
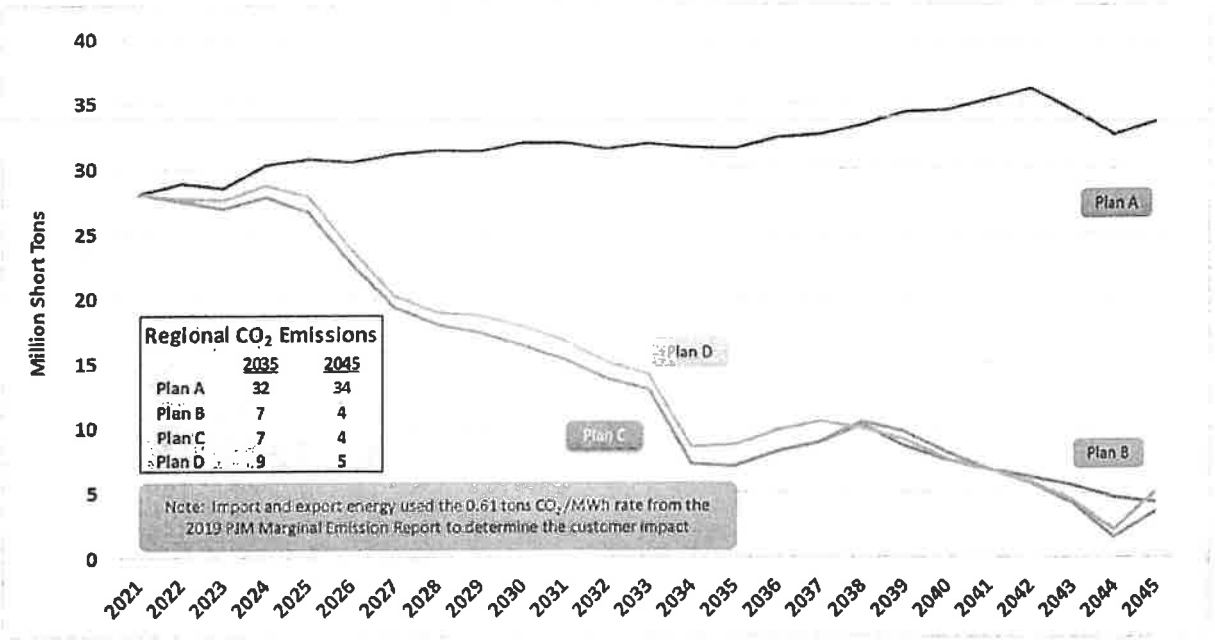


Figure 2.2.6 – Regional CO_2 Output for Alternative Plans



As seen in Figures 2.2.2 through 2.2.4, Plans B through D are all very similar over the first 15 years of each Alternative Plan. This alignment between Alternative Plans B through D over the 15-year Planning Period creates a common pathway for the Company to pursue now while allowing new technologies to emerge and mature, and allowing analysis and study to continue. Accordingly, for this 2020 Plan, the Company recommends a path forward that substantially aligns with the first 15 years of Alternative Plans B through D. Over the longer-term, however, based on current technology and this "snapshot in time," the Company recommends Alternative Plan B.

2.3 Transmission System Reliability Analysis

In order to understand the possible transmission system reliability implications of retiring all Company-owned carbon-emitting generation in 2045, as contemplated by Alternative Plans C and D, the Company performed a transmission system power flow analysis by developing a base power flow case and three different scenarios, and utilizing simplifying assumptions. The initial results of this analysis identified North America Electric Reliability Corporation ("NERC") reliability deficiencies on twenty-six 115 kV lines, thirty-two 230 kV lines, six 500 kV lines, and eleven transmission transformers that would need to be resolved to avoid NERC violations. In addition, the results indicated that Alternative Plans C and D would require construction of four interstate transmission lines at an estimated cost of $8.4 billion. A discussion of this analysis and the full results are provided in Section 7.5.

2.4 NPV Results

The Company evaluated the Alternative Plans to compare and contrast the NPV utility costs for each build plan over the Study Period. Figure 2.4.1 presents these NPV results on the "Total

System Costs" line, as well as the estimated NPV of proposed investments in the Company's transmission and distribution systems, broken down by specific line item.

Figure 2.4.1 – NPV Results

2020 $B	Plan A	Plan B	Plan C	Plan D
Total System Costs[1]	$ 34.7	$ 56.8	$ 60.7	$ 63.0
GT Plan	$ 0.2	$ 3.2	$ 3.2	$ 3.2
SUP	$ 2.2	$ 2.2	$ 2.2	$ 2.2
Broadband	$ -	$ 0.2	$ 0.2	$ 0.2
Transmission Underground Pilot	$ -	$ 0.2	$ 0.2	$ 0.2
Transmission	$ 5.1	$ 5.1	$ 5.1	$ 5.1
Transmission Level Import Increase	$ -	$ -	$ 8.4	$ 8.4
Customer Growth	$ 2.0	$ 2.0	$ 2.0	$ 2.0
Subtotal Plan NPV[2]	**$ 44.3**	**$ 69.7**	**$ 82.1**	**$ 84.3**
Less Benefits of GT Plan	$ -	$ (3.5)	$ (3.5)	$ (3.5)
Total Plan NPV	**$ 44.3**	**$ 66.2**	**$ 78.6**	**$ 80.8**
Plan Delta vs. Plan A	$ -	$ 21.9	$ 34.3	$ 36.6

Notes: (1) Total system costs include the results from Figures 2.2.1 through 2.2.4 plus approved, proposed, and generic DSM; solar interconnection costs; and solar integration costs. (2) Numbers may not add due to rounding.

2.5 Virginia Residential Bill Analysis

The bill of a typical residential customer in Virginia using 1,000 kWh per month as of December 31, 2019, was $122.66. As of May 1, 2020, this typical bill is $116.18, largely attributable to a significant decrease in the fuel factor. The Company calculated the projected residential bill for Alternative Plans A and B over each of the next ten years. Figure 2.5.1 presents the summary results of these projections in 2030, as well as the CAGR. Importantly, these bill projections are not final—all Company rates are subject to regulatory approval. Additionally, the bill projection associated with Alternative Plan A is presented for comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, Plan A does not represent a realistic state of relevant law and regulation.

As can be seen in Figure 2.5.1, about 40% of the projected bill increase from 2020 to 2030 is associated with investments incentivized or mandated by the VCEA and other legislation from the 2020 Regular Session of the Virginia General Assembly. Roughly one-third is attributable to compliance with directives that pre-date 2020, including the GTSA. Overall, the projected bill increase is approximately 2.9% on a compound annual basis using year-end 2019 customer bill as a baseline. The Company used year-end 2019 for this calculation to compare full-year data points. For comparison, in 2008, the year following passage of the Virginia Electric Utility Regulation Act, the bill of a typical residential customer in Virginia using 1,000 kWh per month was $107.20. Using 2008 as a baseline, the projected compound annual growth rate in the typical residential customer bill through 2030 is approximately 2.1%.

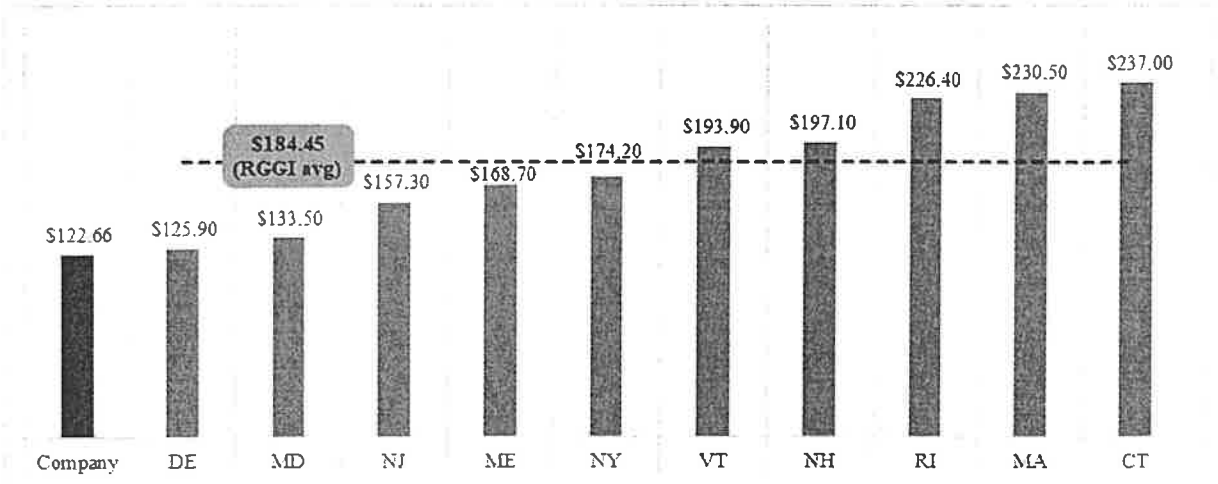
Figure 2.5.1 – Residential Bill Projection (1,000 kWh per Month)

	2030	CAGR
2019 Year End	$122.66	
Plan A[1]	$11.70	0.8%
Pre-2020 Legislation[2]	$15.28	1.0%
2020 Legislation[3]	$18.94	1.1%
Total 2030 Year End	**$168.58**	**2.9%**
Total Bill Increase	$45.92	

Notes: (1) Represents bill projections associated with future generation in Alternative Plan A; approved and proposed investments in DSM; approved investments in the Grid Transformation Plan (*i.e.* Phase IA and IB); investments in the Strategic Underground Program; and compliance with environmental laws and regulations, including CCR investments. (2) Represents bill projections associated with future generation in Alternative Plan B and other investments incentivized or mandated by legislation prior to 2020, including legislation related to pumped storage (2017), the GTSA (2018), and rural broadband (2019). (3) Represents bill projections associated with future generation in Alternative Plan B and other investments incentivized or mandated by the VCEA and other 2020 legislation.

For perspective, the average residential rate for RGGI states normalized for 1,000 kWh monthly usage—approximately $184.45—is approximately 50% higher than the Company's typical residential bill as of year-end 2019 (*i.e.*, $122.66). See Figure 2.5.2.

Figure 2.5.2 – Residential Bill Comparison for RGGI States[1]



Note: (1) Based on residential rate data for RGGI states from U.S. Energy Information Administration as of February 2020, normalized for 1,000 kilowatt-hour monthly usage. Typical 1,000 kilowatt-hour residential bill for Company as of year-end 2019.

Chapter 3: Short-Term Action Plan

The short-term action plan provides the Company's strategic plan for the next five years (2020 to 2025). Generally, the Company plans to proactively position itself in the short-term to meet its commitment to clean energy for the benefit of all stakeholders over the long term. The Company also plans to continue its analyses on how to meet both its clean energy goals and the requirements of the VCEA while continuing to provide safe and reliable service to its customers. As shown in Figures 2.2.2 through 2.2.4, Alternative Plans B through D present the same path forward in the next five years, and substantially similar paths over the next 15 years.

3.1 Generation

Over the next five years, the Company expects to take the following actions related to existing and proposed generation resources:

- File annual plans for the development of solar, onshore wind, and energy storage resources consistent with the RPS requirements established by the VCEA, including related requests for approval of certificates of public convenience and necessity and for prudence determinations related to PPAs;
- Continue the construction of the CVOW demonstration project;
- Continue development and begin construction of a larger build-out of offshore wind off the coast of Virginia;
- Meet its targets under the Virginia RPS at a reasonable cost and in a prudent manner by: (i) applying renewable energy from existing generating facilities, including NUGs; (ii) constructing and operating new renewable energy facilities and energy storage facilities; (iii) purchasing cost-effective RECs, including optimizing RECs produced by Company-owned generation (*i.e.*, when higher priced RECs are sold into the market and less expensive RECs are purchased and applied to the Company's RPS requirements);
- Meet its target under North Carolina Renewable Energy Portfolio Standard at a reasonable cost and in a prudent manner, and submit its annual compliance report and compliance plan;
- Support ongoing Nuclear Regulatory Commission ("NRC") review of the subsequent license renewal application submitted for Surry Units 1 and 2 in October 2018;
- Submit an application to the NRC for the subsequent license renewal for North Anna Units 1 and 2 by the end of 2020;
- Continue developmental work for 300 MW of new pumped hydroelectric storage in southwestern Virginia;
- Achieve a minimum of 10% electricity production at VCHEC through the use of renewable waste wood by the end of 2021;
- Continue to make investments at existing generation units needed to comply with environmental regulations;
- In order to preserve the option to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities in the near term, evaluate sites and equipment for the construction of gas-fired CT units;

Figure 4.4.1.1 –Fuel, Power, and REC Price Commodity Forecast Comparison

Fuel Price	Planning Period Comparison Average Value (Nominal $)		
	2018 Plan Federal CO_2 [3]	2019 Update Virginia in RGGI [3]	2020 Plan Mid-Case Federal CO_2 with Virginia in RGGI [3]
Henry Hub Natural Gas[1] ($/MMbtu)	4.29	3.81	4.05
Zone 5 Delivered Natural Gas[1] ($/MMbtu)	3.71	3.54	3.68
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.66	2.42	2.97
No. 2 Oil ($/MMbtu)	18.52	17.78	17.89
1% No. 6 Oil ($/MMbtu)	11.93	11.56	11.52
Electric and REC Prices			
PJM-DOM On-Peak ($/MWh)	41.29	38.94	44.58
PJM-DOM Off-Peak ($/MWh)	34.36	32.79	34.78
PJM Tier 1 REC Prices[4] ($/MWh)	5.73	6.72	9.13
RTO Capacity Prices[2] ($/KW-yr)	59.33	62.50	57.34

Notes: 1) Zone 5 natural gas price used in Plan analyses. Henry Hub prices shown to provide market reference.
2) Capacity price represents actual clearing price from the PJM RPM base residual auction through delivery year 2020/2021 for 2018 Plan, and through delivery year 2021/2022 for the 2020 Plan and 2019 Update.
3) 2018 Planning Period 2019-2033, 2019 Planning Period 2020-2034, 2020 Planning Period 2021-2035.
4) The 2018 Plan column reflects the PJM Tier 1 REC prices as filed in the 2018 Compliance Filing.

4.4.2 No CO_2 Tax Commodity Forecast

The No CO_2 Tax commodity forecast anticipates a future without any new regulations or restrictions on CO_2 emissions beyond those already in place or previously approved. DOM Zone peak energy prices are slightly lower than the Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast across the Planning Period because there is no incremental requirement to comply with CO_2 regulation targets to pass through to power prices. Given forthcoming law in Virginia imposing CO_2 regulation, this assumption is, in the Company's view, no longer reasonable. The No CO_2 Tax forecast is utilized only in analysis of Alternative Plan A, which is presented solely to measure additional costs of various planning scenarios.

4.4.3 Virginia in RGGI Commodity Forecast

The Virginia in RGGI commodity forecast includes New Jersey and Virginia as new participants in RGGI (Virginia in 2021), along with the nine existing RGGI states. The key assumptions regarding market structure and the use of an integrated, internally-consistent fundamental based modeling methodology remain consistent with those utilized in the other commodity forecast except that the carbon program modeled is RGGI and that there is no federal program addressing CO_2 reduction targets.

RGGI utilizes an emissions containment reserve ("ECR") as a trigger to limit downward pressure on the CO_2 allowance price. The ECR price trigger starts at $6 in 2021 and increases at 7% annually. If triggered, the ECR withholds up to 10% of the auction budget of states opting to implement the ECR (the ECR is modeled for all states but Maine and New Hampshire). In the

Virginia in RGGI commodity forecast, the RGGI prices are forecasted to be below the ECR trigger price and, therefore, in ICF's model the emission budget (cap) is reduced by 10% in the years it is triggered. Even with the 10% reduction in allowances, the market clearing prices remain below the ECR trigger prices. The reason for the lower clearing prices is that the CO_2 allowance supply in this case is driven not by coal generation displacement, but by the state policies (in member states) that continue to drive non-fossil generation growth. Carbon reductions are being driven by the high RPS targets in many of the RGGI states, with several states targeting 50% renewable or clean energy standards by the 2030 to 2035 timeframe, and further increasing beyond those years. Additionally, offshore wind procurements are modeled in 7 of the 11 RGGI states (*i.e.*, RI, VA, CT, MA, MD, NJ, NY), providing added clean energy in the RGGI region and displacing fossil resources. As noted earlier, the Virginia in RGGI commodity forecast does not include the regional effects of VCEA on RGGI allowance prices; therefore, the forecast does not account for the additional carbon reductions associated with the revised RPS requirements in Virginia.

4.4.4 High-Case Federal CO_2 Commodity Forecast

The High-Case Federal CO_2 commodity forecast addresses a scenario with a more stringent CO_2 regulatory environment implemented nationwide. In this commodity forecast, CO_2 regulation is addressed as a legislative approach to a national mass cap-and-trade program that begins in 2028 and targets an approximately 80% reduction from 2005 sector emissions by 2050. This target is similar to CO_2 reduction levels being discussed by several states, and it is consistent with what was proposed under the Waxman-Markey Bill in 2009. Load under this scenario increases relative to the other cases because of state electrification efforts. The tightening carbon cap and higher load compared to the No CO_2 Tax commodity forecast leads to higher renewable buildout and lower nuclear retirements. The "high" case includes existing and new sources under a national cap and trade program. This representation assumes that all states participate in the program except for California, which maintains its state-specific program. In this commodity forecast, ICF assumed that Virginia does not join RGGI. Compared to the Mid Case Federal CO_2 with RGGI in Virginia commodity forecast, the power prices are lower in the near term, while post-2025 all hours prices are roughly 36% higher on average. The higher power price is driven by CO_2 allowance price in excess of $100/ton by 2050.

4.4.5 Capacity Price Forecasting Methodology

In most wholesale electricity markets, electric power generators are paid for providing:

- Energy: the actual electricity consumed by customers;
- Capacity: standing ready to provide a specified amount of electric energy; and
- Ancillary Services: a variety of operations needed to maintain grid stability and security, including frequency control, spinning reserves, and operating reserves.

The purpose of a mandatory capacity market is to encourage new investments where they are most needed on the grid. PJM's capacity market (*i.e.*, the RPM), ensures long-term grid reliability by procuring the appropriate amount of supply- and demand-side resources needed to meet predicted peak demand in the future. In a capacity market, utilities or other electricity

suppliers are required to purchase adequate resources to meet their customers' demand plus a reserve amount. Suppliers offer supply- or demand-side resources into the capacity market at a price. To the extent the supply offer clears the market, then those capacity resources are obligated to supply energy (or reduce energy in the case of demand-side resources) when dispatched, or pay penalty fees.

The RPM is designed to provide financial incentives to attract and maintain sufficient capacity to meet the load demands anticipated by PJM; in concept, revenues from energy and ancillary services plus capacity payments should equal the amount necessary to attract new entry. Parallel to the actual market construct, forecasting of long-term capacity prices is based on estimating the amount of capacity revenue a generation resource requires, in addition to revenue from energy and ancillary services. The capacity revenue forecast represents the amount by which a resource's cost exceeds its forecasted wholesale electricity market revenues. The basic concept utilized in forecasting is that in order to maintain appropriate reserve levels to assure reliable electric service, generating resources will require sufficient revenue to cover expenses and, when necessary, support the required new investment. When wholesale market energy and ancillary services revenue is not sufficient, then capacity revenues are required to fill this gap.

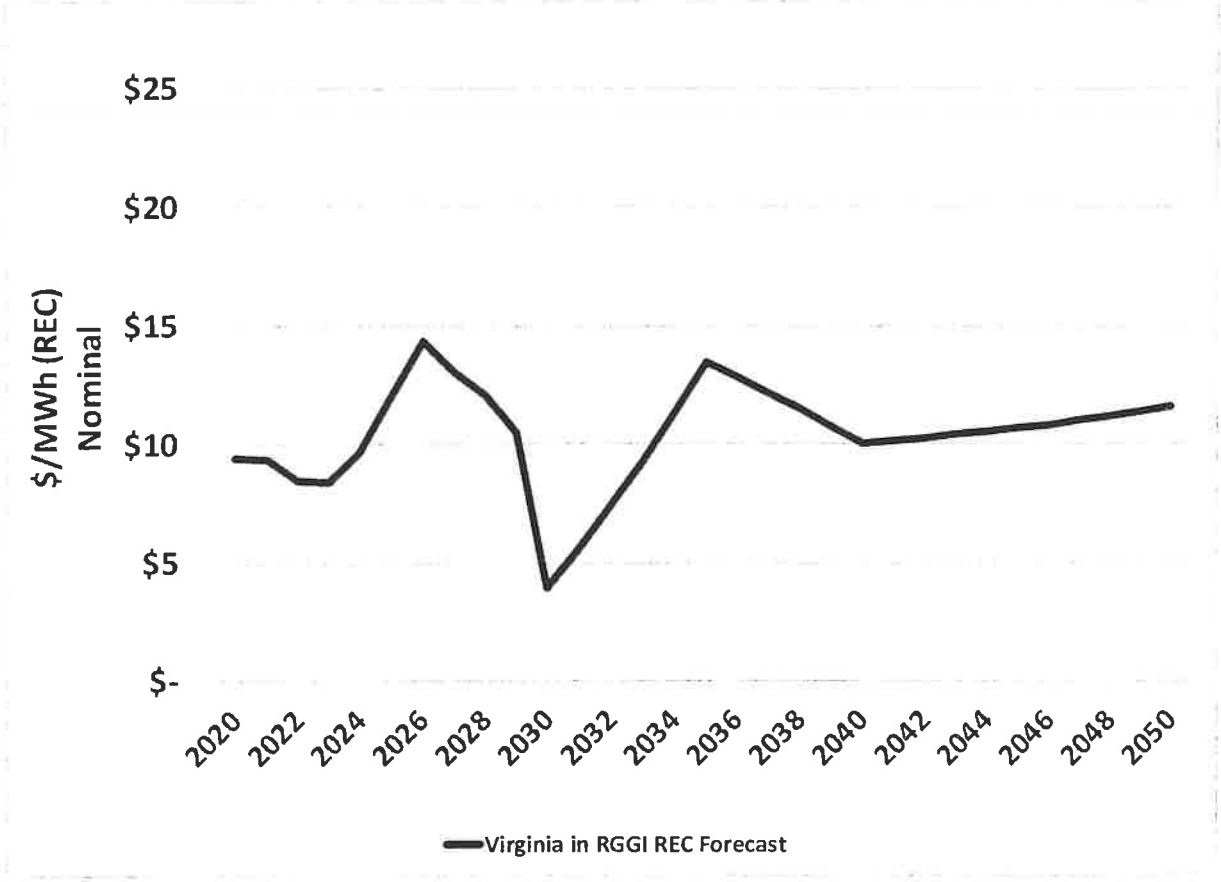
When forecasting capacity prices over long periods, it is reasonable to assume markets will move toward equilibrium and will provide sufficient revenue to support existing resources and incent investment in new resources that require equity returns on the capital expended for development and construction of the new resource. In markets with excess capacity, existing resources generally set the capacity price. These resources require revenue to cover only operating expenses and do not include equity returns or significant going forward capital expenditures. Because of this, the capacity price tends to be lower in markets with excess capacity. However, over the long term, the market is expected to move to an equilibrium status where sufficient revenues are provided, which assures adequate resource capacity and encourages market efficiency. Note that while long-term forecasts tend toward an equilibrium pricing, it is expected that actual markets will continue to follow an up-and-down cycle that moves around equilibrium levels. Long-term forecasts for capacity focus on the equilibrium level pricing rather than attempting to estimate the cyclical movement.

For these reasons, the issues surrounding the FERC MOPR Order described is Section 1.6.1 do not change the methods used to develop long-term capacity price forecasts.

4.4.6 REC Price Forecasting Methodology

Together with ICF, the Company developed a revised methodology for forecasting REC Tier 1 prices from what was presented in the 2018 Plan. A white paper describing the forecasting methodology and providing details related to the revised methodology for forecasting REC prices is provided in Appendix 4Q. The white paper also includes a section that illustrates the impact on REC prices if the federal tax credits for production tax credits and investment tax credits are extended indefinitely. Figure 4.4.6.1 provides a graph of the REC price forecast for the Virginia in RGGI commodity forecast.

Figure 4.4.6.1 – Tier 1 REC Forecast Comparison



The shape of the REC price forecast illustrated in Figure 4.4.6.1 reflects the fundamental changes occurring in the PJM states' RPS programs and the advancement of state-sponsored offshore wind development. The early price rise forecasted for Tier 1 RECs reflect recently enacted increases in RPS programs in several PJM states. These same states have implemented offshore wind procurement programs designed to supply large amounts of RECs to meet the expanding RPS requirements. The curve through 2030 reflect these fundamental developments, with prices rising as demand for RECs increase with the expanding RPS requirements, but then declining sharply as the large amounts of offshore wind procured by the states provide ample amounts of RECs to meet demand. As noted earlier, these results do not include the regional impacts of the VCEA.

4.5 Virginia Renewable Portfolio Standard Assumptions

In Virginia, the VCEA established a mandatory RPS as discussed in Section 1.2. In this 2020 Plan, the Company optimized the model for each Alternative Plan according to its typical process. The Company then determined whether additional renewable resources were needed to meet the annual RPS requirements, and added additional renewable resources (either Company-build or PPA) as needed. The Company assumed that it could construct or purchase renewable resources at less than the $45/MWh deficiency payment in the VCEA.

Attachment 28

Virginia:

In the Circuit Court of the City of Richmond, John Marshall Courts Building

VIRGINIA MANUFACTURERS ASSOCIATION	)	
Petitioner,	)	
v.	)	**Case No.: CL20-4918**
VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY, DAVID PAYLOR DIRECTOR, VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY, AND THE VIRGINIA STATE AIR POLLUTION CONTROL BOARD;	)	
Respondents.	)	

OPINION ORDER

Virginia Manufacturers Association (hereinafter, "VMA") came before the Court on June 30, 2021, to be heard on its Petition for Appeal which named the Virginia Department of Environmental Quality, David Paylor, and the Virginia State Air Pollution Control Board (hereinafter, "Respondents" or "DEQ") as Respondents. The Court took the matter under advisement and denies VMA's petition for the reasons set forth below.

I. Procedural History

VMA filed a Petition for Appeal on October 2, 2020 asserting six Assignments of Error, four of which outline how DEQ allegedly violated the Virginia Administrative Process Act ("VAPA") when it amended the regulation governing Virginia's CO_2 Budget Trading Program. The remaining Assignments of Error allege that the amended regulation is constitutionally infirm because it is both void for vagueness and levies a tax in violation of Article X, Section 7 of the Virginia Constitution. To remedy the alleged violations, VMA asks the Court to invalidate, vacate, and declare the amended regulation null and void.

On October 20, 2020, Virginia Interfaith Power & Light, Wetlands Watch, and Appalachian Voices (collectively, the "Conservation Organizations") filed a Motion to Intervene as Respondents. The Court denied the Motion to Intervene on February 9, 2021 for the reasons stated in the Court's Letter Opinion.

On October 28, 2020, DEQ filed a Motion to Dismiss the Petition for Appeal. The Court denied the Motion to Dismiss on January 29, 2021.

The Court entered a briefing schedule Order on April 1, 2021, and the parties' briefs were submitted in compliance with the deadlines established therein. On May 7, 2021, the Conservation Organizations filed a Motion for Leave to File an *Amicus Curiae* Brief in Support of Respondents. The *amicus* brief was filed contemporaneously with the motion.[1] The *amicus* brief assists the Court in deciding the issues presented in this appeal and therefore, the Court will take it into consideration. 4 Am. Jur. 2d *Amicus Curiae* §§ 1, 5 (2021); *Jones v. Caldwell*, 61 Va. Cir. 408 (2003).

II. Factual Background

As a preliminary matter, the issue on appeal is whether the amendment of the CO_2 Budget Trading Program was lawful. VMA devoted a considerable amount of time arguing that the amended trading program imposes significant financial burdens on the entities required to participate and that similar programs have failed to effectively reduce carbon emissions. On the other hand, DEQ argues that the trading program reduces CO_2 emissions, improves public health, and helps keep electricity costs down. The parties' dispute whether the CO_2 Budget Trading Program is "good" for the Commonwealth or "successful" in accomplishing the goal of reducing CO_2 emissions is irrelevant to the questions presented. However, the history of the CO_2 Budget Trading Program and the events preceding this appeal must be discussed to better understand the legal issues presented.

a. The Original Regulation

In June of 2016, former Governor McAuliffe issued Executive Order 57 which directed the Secretary of Natural Resources to convene a study and recommend ways in which the Commonwealth could attempt to reduce the amount of carbon dioxide emitted by utilities that produce electricity. The study group recommended, among other things, the need to promulgate a regulation "limiting the total amount of carbon dioxide emitted from electric power facilities." Va. Exec. Directive No. 11 (May 16, 2017). Governor McAuliffe agreed, directed DEQ to promulgate a regulation, and specified that it should:

a. Include[] provisions to ensure that Virginia's regulation is 'trading-ready' to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and

b. Establish[] abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits.

Id. DEQ published the proposed regulation in January of 2018 and presented it to the State Air Pollution Control Board for consideration for approval for public comment. *Id.* The regulation was re-proposed in February of 2019 to address feedback received from the VAPA notice and comment

[1] Although the Conservation Organizations were not subject to the filing deadlines set forth in the Court's briefing schedule Order, the *amicus* brief was filed in accordance with the deadlines applicable to DEQ.

process, and more public comment was received. Pet. for Appeal ¶ 33. The Air Board adopted the regulation (hereinafter, the "Original Regulation") on April 19, 2019, and it was published as a new chapter of the Air Board's regulations on May 27, 2019. *Id.* ¶ 35. Neither party disputes that the Original Regulation was fully vetted through the VAPA. *Id.* ¶ 33.

The Original Regulation established the Virginia component of the CO_2 Budget Trading Program. Designed to operate as a consignment-based, conditional allowance program, it proscribed that CO_2 allowances would be allocated to electricity manufacturers, sold by the manufacturers into an auction market, and thereafter repurchased by the manufacturers at auction. Pet. for Appeal ¶ 30-31. The auction market into which the CO_2 allowances were to be sold and purchased was that created by the Regional Greenhouse Gas Initiative ("RGGI"). *Id.* ¶ 31. At oral argument, the parties conceded that RGGI is the only currently existing auction house for trading CO_2 allowances.

Although properly adopted and intended to go into effect in 2020, the General Assembly passed a budget provision preventing DEQ from implementing the program and joining RGGI as a consignment member. H.B. 1700, CH. 854, Item 4-5.11, Reg. Sess. (Va. 2019).

b. The Clean Energy and Flood Preparedness Act

In 2020, the General Assembly struck the budgetary restriction. H.B. 29, Ch. 1283, Item 4-5.11, Reg. Sess. (Va. 2020). With the Original Regulation still intact, Virginia was permitted to join or participate in RGGI as a consignment member. Instead, the General Assembly enacted the Clean Energy and Flood Preparedness Act (the "Act"), Virginia Code § 10.1-1329 *et seq.*, which authorized DEQ to move away from the consignment-based model and establish a direct auction trading system.

The Act authorized the Director of DEQ "to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article." Va. Code § 10.1-1330(B). The Act also directed DEQ to incorporate "[t]he provisions of this article" into the Original Regulation "without further action by the [Air Pollution Control] Board," and provided that "[s]uch incorporation . . . shall be exempt from the" VAPA. Va. Code § 10.1-1330(A).

On July 10, 2020, DEQ issued Revision A20 (hereinafter, the "Amended Regulation") which amended the Original Regulation by converting the CO_2 Budget Trading Program from the prior consignment-based model to a direct auction trading system. VMA argues that DEQ acted beyond the scope of the Act's exemption in doing so and that no other VAPA exemptions save its actions. VMA additionally argues that the Amended Regulation is both unlawfully vague and imposes a tax which DEQ is not authorized to levy.

III. Standard of Review

As VMA is the "the party complaining of agency action," it carries the burden "to designate and demonstrate an error of law subject to review." Va. Code § 2.2-4027.

> Such issues of law include: (i) accordance with constitutional right, power, privilege, or immunity, (ii) compliance with statutory authority, jurisdiction

> limitations, or right as provided in the basic laws as to subject matter, the stated objectives for which regulations may be made, and the factual showing respecting violations or entitlement in connection with case decisions, (iii) observance of required procedure where any failure therein is not mere harmless error, and (iv) the substantiality of the evidentiary support for findings of fact.

Id. The issues in this appeal concern matters of statutory interpretation. "A question of statutory interpretation is subject to review *de novo* on appeal." *Karr v. Va. Dep't of Envtl. Quality*, 66 Va. App 507, 513 (2016) (internal quotation and citations omitted). The parties do not dispute that the issues raised in VMA's Petition for Appeal present questions of statutory and constitutional interpretation. Accordingly, the Court must analyze the Act and DEQ's actions in accordance with well-settled principles of statutory interpretation to determine whether DEQ had "statutory authorization" to issue the Amended Regulation and whether "it did so within the statutory limits of its discretion and with the intent of the statute in mind[.]" *Va. Jockey Club, Inc. v. Va. Racing Comm'n*, 22 Va. App. 275, 286 (1996) (internal quotations and citation omitted). In doing so, the Court does not construe the statue "by singling out a particular phrase." *Va. Electric & Power Co. v. Citizens for Safe Power*, 222 Va. 866, 869 (1981).

IV. Discussion

a. Whether Amending the Regulation Was Exempt from the VAPA

VMA asserts the Act did not grant the Director of DEQ an unbridled VAPA exemption to substantively amend the Original Regulation. According to VMA, the General Assembly permitted the Director to incorporate or, in essence, lift the language from the Act and place it into the Original Regulation. It argues that any further action was subject to the requirements of the VAPA. Because DEQ allegedly acted outside the scope of the Act's VAPA exemption, VMA requests the Court to declare the Amended Regulation null and void.

As an initial matter, VMA claims that DEQ cannot invoke the VAPA exemption contained in Virginia Code § 2.2-4006(A)(4)(a). DEQ has conceded that it does not attempt to claim that exemption. Pursuant to Virginia Code § 2.2-4006(A)(4)(a), DEQ is permitted to bypass the VAPA when issuing regulations "[n]ecessary to conform to changes in Virginia statutory law or the appropriation act where no agency discretion is involved." The Court agrees with DEQ that it never intended to, nor needed to, invoke this exemption. The Act contains a specific VAPA exemption rendering it unnecessary for DEQ to seek to comply with one which is broader and more generalized. Va. Code § 10.1-1330(A).

VMA concedes that "DEQ was permitted to avoid [V]APA procedural requirements for a revision" but argues that the exemption only permitted DEQ to copy the language of the Act and paste into the Original Regulation verbatim. Pet'r Br. in Supp. 19. Converting the CO_2 Budget Trading Program to a direct auction trading system, it argues, fell outside the scope of the Act's VAPA exemption and therefore, the Amended Regulation must be nullified because it was not vetted through the VAPA.

When the language of a statute is "clear and unambiguous," the Court is to "assign the statute its plain meaning." *Browning-Ferris Indus. v. Residents Involved in Saving the Env't, Inc.*, 254 Va. 278, 284 (1997). "The plain, obvious, and rational meaning of [the] statute is preferred

over any curious, narrow, or strained construction." *Karr*, 66 Va. App. at 527 (quoting *Commonwealth v. Zamani*, 256 Va. 391, 395 (1998)).

The Act directs DEQ to incorporate its provisions into the Original Regulation. "Incorporate," as that word is commonly used, means "to unite or work into something already existent so as to form an indistinguishable whole." *Incorporate*, Merriam-Webster.com, https://www.merriam-webster.com/dictionary/incorporate (last visited July 12, 2021). In context, DEQ was directed to take the provisions of the Act and unite them into the Original Regulation to create an indistinguishable regulation applicable to electricity manufacturers that emit CO_2. The incorporation language specifically identifies the already existent regulation into which the Act is to be incorporated – the Original Regulation – and expressly provides that the Air Board need not approve, and the VAPA shall not apply to, such incorporation. Va. Code § 10.1-1330(A).

It is well-settled "that every part of a statute is presumed to have some effect and no part will be considered meaningless unless absolutely necessary." *Hubbard v. Henrico Ltd. P'ship*, 255 Va. 335, 340 (1998). VMA argues that the General Assembly directed DEQ to take the language of the Act and add it to the Original Regulation verbatim. In other words, the General Assembly directed DEQ to recite what the General Assembly had already stated. Doing so, however, would have produced no change. The Original Regulation would proscribe the particulars of a consignment-based trading program but state that DEQ is authorized to "establish, implement, and manage" one that operates differently. If VMA were correct in arguing that DEQ had to comply with the VAPA before converting the Original Regulation to a direct auction program, the trading program would remain unchanged, and the Amended Regulation would have provided nothing more than what was stated in the Act itself. The amendment contemplated by VMA would have been wholly ineffectual.

When interpreting the plain language of a statute, the Court is to construe it "so as to avoid an absurd result." *Eastlack v. Commonwealth*, 282 Va. 120, 126 (2011) (citing *Commonwealth v. Doe*, 278 Va. 223, 230 (2009)). Here, however, VMA singles out the language of incorporation without reading the Act in context. If its cut and paste argument were correct, DEQ would have produced a convoluted and confusing regulatory scheme. The Original Regulation would specify how the consignment-based trading program shall operate and define terms such as "conditional allowances" and "consignment auctions." It would simultaneously state that the Director of DEQ is "authorized to establish, implement, and manage" a direct auction trading program under which CO_2 allowances are not consigned and consignment auctions are not held.

Further confusion would result from a verbatim transfer of language because certain language in the Act has no application to manufacturers required to participate in the CO_2 Budget Trading Program. For instance, VMA claims that DEQ failed to include a provision of the Act stating that the revenues generated by DEQ's sale of CO_2 allowances will be held by the state treasury and spent for enumerated purposes. Va. Code § 10.1-1330(C). It would be nonsensical to include such language in a regulation governing electricity manufacturers. The enacted language was not a directive to DEQ. Instead, its inclusion was necessitated by the fact the General Assembly authorized DEQ to sell CO_2 allowances directly into the auction market rather than

consign them to participants.[2] Determining what to do with the revenue generated from those sales was a question for the General Assembly which it answered in the Act.

Furthermore, VMA believes the General Assembly directed DEQ to add to the Original Regulation an entirely new set of definitions – those set forth in Virginia Code § 10.1-1329 – effectively creating two sets of definitions in a single regulation. Not only would doing so have been duplicative of certain definitions included in the Original Regulation, the newly defined terms would be meaningless. The newly added set of definitions would clarify that "'DHCD' means the Department of Housing and Community Development" and define what an "energy efficiency program" is, yet neither the abbreviation nor the phrase are used in the regulation itself. Va. Code § 10.1-1329. The newly added definitions would also be prefaced with the phrase, "[a]s used in this article, unless the context requires a different meaning[,]" yet appear in a regulation. *Id.*

The General Assembly did not direct DEQ to amend the Original Regulation in a manner which would only confuse those required to participate and substantively amend nothing. Rather, it authorized DEQ to convert the trading program to a direct auction trading system and directed DEQ to sell, not consign, CO_2 allowances. The General Assembly not only authorized this change, but it also exempted DEQ from requirements which would otherwise apply in the absence of language to the contrary.

It is worth noting that when DEQ issued the Original Regulation in response to the Governor's directive, it had to both comply with the VAPA and receive Air Board approval. If the General Assembly had not included the exemption in this new Act, the Amended Regulation would have been subject to the same requirements and the amendment process would have been prolonged.

VMA attempts to distinguish the VAPA exemption language from other instances in which the General Assembly granted exemptions, yet the examples they provided either applied to the enactment of wholly new regulations or contained differing exemption language for different mandates. The exemption language here applies to the amendment of a preexisting regulation and does not differentiate between exempt and non-exempt actions. "Courts assume that the General Assembly chose, with care, the words it used in enacting the statute." *Kalergis v. Comm'r of Highways*, 294 Va. 260, 266 (1017). If the General Assembly intended for the VAPA to apply, it would have stated so. In fact, in the same session in which the Act was enacted, the General Assembly did so expressly when it added a new subsection E to Virginia Code § 10.1-1308 which states: "Regulations adopted by the [Air Pollution Control] Board under this subsection shall be subject to the requirements set out in" specific provisions of the VAPA.[3]

The Court recognizes that bypassing the VAPA may have prevented interested parties from providing important input into the rulemaking process, but DEQ did what the General Assembly

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[2] Under the Original Regulation, DEQ was to consign the allocated number of CO_2 allowances to manufacturers. However, the Act stated that DEQ "shall seek to *sell* 100 percent of all allowances issued each year through the allowance auction[.]" Va. Code § 10.1-1330(B) (emphasis added). The revenue generated from the sale of allowances is to be held by the state treasury and used for environmental mitigation purposes. Va. Code § 10.1-1330(C).

[3] Other state statutes that authorize the issuance of regulations establishing the state's CO_2 Budget Trading Program expressly require compliance with that state's version of the APA, yet the General Assembly in this case provided the exact opposite. *See* Conn. Gen. Stat. § 22a-200c (requiring that adoption of such regulations be "in accordance with" Connecticut's Uniform Administrative Procedure Act).

required it to do. Therefore, the Court **FINDS** that DEQ did not violate the VAPA in issuing the Amended Regulation.

b. Whether DEQ Impermissibly Added a Permitting Requirement

VMA argues that the Amended Regulation impermissibly added a permitting requirement which was neither found in the Original Regulation nor authorized by the Act. DEQ argues that the Original Regulation contained the same permitting requirement and therefore, this provision of the Amended Regulation remains unchanged.

Subsection A of the "Applicability" provision specifies which manufacturers are required to participate in the CO_2 Budget Trading Program. 9 VAC 5-140-6040(A). Subsection B of the "Applicability" provision previously stated:

> *Exempt* from the requirements of this part is *any* fossil fuel *CO_2 budget source* located at or adjacent to and physically interconnected with a manufacturing facility that, prior to January 1, 2019, and in every subsequent calendar year, *met either of the following requirements*:
>
> . . .
>
> "Such CO_2 *budget source* shall have an operating permit containing the applicable restrictions *under this subsection*."

9 VAC 5-140-6040(B) (2019) (emphasis added) (amended 2020). The Amended Regulation merely added the word "exempt" to say: "Such exempt CO_2 budget source shall have an operating permit containing the applicable restrictions under this subsection." 9 VAC 5-140-6040(B). The permit requirement in the Original Regulation clearly applied to exempt budget sources. The word "exempt" only clarified, but did not change, what was previously required.

The other change VMA takes issue with is a provision clarifying that exempt budget sources must file an application permit by January 1, 2022. 9 VAC 5-140-6040(B). The Original Regulation required all CO_2 budget sources to file an application permit by January 1, 2020; however, that deadline was rendered obsolete as the Amended Regulation was issued on July 10, 2020. If DEQ had not changed the permitting deadline, the Amended Regulation would require budget sources to submit permit applications after the deadline for doing so had expired. DEQ simply extended the generally applicable permitting deadline to January 1, 2021 and provided exempt budget sources with a further extended deadline of January 1, 2022. *Compare* 9 VAC 5-140-6040(B), *with* 9 VAC 5-140-6150.

Exempt and non-exempt manufacturers are subject to the same permitting requirements that were set forth in the Original Regulation. The other change only extends the deadline by which exempt budget sources must submit permitting applications. For these reasons, the Court **FINDS** that the Amended Regulation did not add a new permitting requirement and that DEQ did not otherwise act outside the scope of the VAPA exemption.

c. Whether the Amended Regulation is Void for Vagueness

VMA argues that the Amended Regulation is so vague that no participant of ordinary intelligence can discern what is necessary for compliance. Specifically, VMA alleges that the Amended Regulation fails to define key operational aspects of the CO_2 Budget Trading Program such as how CO_2 allowances are to be obtained. It also asserts that the Amended Regulation does not mention "Regional Greenhouse Gas Initiative" or "RGGI" but participants must comply with RGGI's internal rules, which are "de facto" rules subject to the VAPA.

First, VMA has not pointed to any case in which the void for vagueness doctrine has been applied in the regulatory context. It cites to *Tanner v. City of Va. Beach*, 227 Va. 431 (2009) (analyzing whether a city noise ordinance was facially vague or vague as applied to plaintiffs) and *Volkswagen of Am., Inc. v. Smit*, 279 Va. 327 (2010) (analyzing whether a statute was impermissibly vague as applied), but neither case contains a claim similar to the one asserted here. Furthermore, *Tanner* and *Volkswagen* establish that VMA carries a high burden to prevail on this assertion.

Second, VMA has not pointed to any vague or incomprehensible provision within the Amended Regulation. To comply with the CO_2 Budget Trading Program, electricity manufacturers must hold CO_2 allowances in an amount equal to or greater than the amount of CO_2 they emit. 9 VAC 5-140-6050(C). VMA participated in the development of the Original Regulation, and all material aspects of this provision remain identical. A statute, and perhaps also a regulation, is not vague if it can be "construed reasonably in a manner that will render its terms definite and sufficient[.]" *Tanner*, 227 Va. at 438-39. The Amended Regulation sets forth what the manufacturers need to do for compliance purposes – hold a certain amount of CO_2 allowances relative to the amount of CO_2 they emit – using explicit and definite terms. It specifies which entities must participate, the requirements for permitting and monitoring, where the allowances are to be held, how compliance is measured, penalties for non-compliance, recordkeeping requirements, and how Virginia's budget for allowances will change over time. The Amended Regulation sufficiently details what manufacturers are required to do for compliance purposes, and Virginia has since held two successful auctions with no reported confusion.

VMA next asserts that the rules governing the actual trading market are "de facto" rules created by RGGI which may change in the future and potentially deprive participants of their due process rights. However, the Original Regulation also required participants to use the RGGI auction house for trading allowances. *See* Pet. for Appeal ¶¶ 34, 36. VMA's concern that RGGI rules may change in the future are merely hypothetical and not ripe for review. Furthermore, the cases VMA cites for this proposition are inapposite because they involve an agency's interpretation of a regulation. *See Va. Bd. of Med. v. Va. Physical Therapy Ass'n*, 13 Va. App. 458 (1991); *Jerri's Ceramic Arts, Inc. v. Consumer Prod. Safety Comm'n*, 874 F.2d 205 (4th Cir. 1989). Lastly, manufacturers are only required to comply with RGGI rules if they choose to acquire allowances through the RGGI auction market. They are free to acquire the required amount of allowances on a secondary market.

For the foregoing reasons, the Court **FINDS** that VMA's vagueness claims fail.

d. Whether the Amended Regulation Imposes an Unconstitutional Tax

VMA alleges that the Amended Regulation imposes an illegal tax DEQ is not authorized to levy. It claims that participants will incur costs in complying with the Amended Regulation which will then be passed down to consumers under the guise of an "environmental compliance cost" which is a tax. Because the General Assembly possesses the authority to impose taxes and has not delegated such authority to DEQ, the Amended Regulation must be declared null and void.

This taxation argument focuses on the revenues the CO_2 Budget Trading Program will generate. DEQ argues that it only sells the CO_2 allowances into the market and enforces the Amended Regulation. While the revenue is generated from the sale by DEQ, it argues that it does nothing with respect to such revenues after the sale has been made. The Court agrees. The General Assembly directed DEQ to establish, implement, and manage the CO_2 Budget Trading Program. Va. Code § 10.1-1330(B). It also authorized DEQ to sell rather than consign CO_2 allowances. *Id.* As VMA notes, DEQ did not copy and paste Virginia Code § 10.1-1330(C) into the Amended Regulation, but it did not need to do so as discussed above. Aside from the requirements set forth in Amended Regulation, DEQ has no role.

VMA conceded at oral argument that the Amended Regulation does not cloak DEQ with authority to decide where the revenue is to be held or how it is to be spent. The operational aspects concerning revenues generated is controlled by the statute itself. Va. Code § 10.1-1330(C). As part of the Act, the General Assembly directed the state treasury to hold and allocate the auction proceeds. *Id.* The General Assembly also declared that the state treasury shall distribute the proceeds "without further appropriation." *Id.*

Because VMA's constitutional challenge is directed at the Act itself, the Court **FINDS** that the Amended Regulation is not violative of the Virginia Constitution.

V. Conclusion

Upon consideration of the pleadings, briefs, argument of counsel, and for the reasons discussed above, the Court **FINDS** that DEQ did not violate the VAPA or the Virginia Constitution when it issued the Revised Regulation. Therefore, VMA's Petition for Appeal is hereby **DISMISSED**.

Pursuant to Rule 1:13 of the Supreme Court of Virginia, the Court dispenses with the Parties' endorsement of this Order.

The Clerk is directed to forward a copy of this Order to all parties.

It is so **ORDERED**.

ENTER: 7/14/21

Beverly W Snukals

Judge

Attachment 29

https://richmond.com/news/state-and-regional/govt-and-politics/the-mystery-of-the-secret-virginia-air-board-document/article_4bc77dff-7562-53c8-a65b-eabb1af3c34d.html

FEATURED

The mystery of the secret Virginia air board document

Patrick Wilson
May 13, 2022

DEQ Director Mike Rolband addressed the Virginia State Air Pollution Control Board during its meeting at the Parha on April 20.

SHABAN ATHUMAN/TIMES-DISPATCH

Patrick Wilson

Air Pollution Control Board Member Hope Cupit tells Virginia DEQ Director Mike Rolband that the Virginia attorney general's office gave her a document in March saying Virginia's participation in the Regional Greenhouse Gas Initiative is up to the General Assembly, not the Air Board.

State officials are refusing to release a document that purportedly undercuts Gov. Glenn Youngkin's desire to remove Virginia from a greenhouse gas reduction program.

Youngkin wants the Virginia State Air Pollution Control Board to consider an emergency regulation that would remove Virginia from the **Regional Greenhouse Gas Initiative**, a multistate program in which energy producers charge their customers to cover the costs of reducing pollution.

But a member of the air board said at the panel's April 20 meeting that the attorney general's office believes only the General Assembly can remove Virginia from the program.

Hope Cupit said she received an "opinion" in March from the attorney general's office. But she and the attorney general's office declined to release it. A staffer with the Virginia Department of Environmental Quality said someone there had the document "at one point."

People are also reading...

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DEQ's Natalie Womack declined to explain how someone at DEQ had the document "at one point" but supposedly no longer has it.

In any event, the mysterious document — which would undercut Youngkin's goal — remains secret.

After he was elected, Youngkin **gave a speech in December** saying he would remove Virginia from the greenhouse program, known as RGGI, by executive action. But the General Assembly passed a law in 2020 requiring Virginia to join the program, and a governor doesn't have the power to overturn a law.

Under RGGI, energy producers in a number of states trade emission reductions for credits, or buy credits to emit carbon dioxide past a cap. The states in the program are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia.

Youngkin **backed off his plan**, and instead issued an **executive order** calling on the air board to consider a regulation removing Virginia from RGGI. Environmental groups say even that would be illegal because a regulatory board can't overturn a state law.

Cupit, the air board member, asked DEQ Director Mike Rolband at the April 20 board meeting about the administration's plan for an emergency regulation for the air board to consider. (Air board members are appointed by the governor, and DEQ

acts as staff to the air board.)

DEQ staff in March **issued a report** — as requested by Youngkin's executive order — about how the agency believes Virginia could remove itself from the program.

Rolband told her the process was "complicated" and is being "vetted by a lot of different people."

He said the emergency regulation would need review and approval by the air board, and that would begin the process of removing the state from RGGI, which DEQ's report said was an "emergency" because of the costs. Rolband said the attorney general's office would review everything first.

That's when Cupit introduced an issue that seemed to surprise Rolband.

"I did reach out to the attorney general's office and was told that this is not an action of the board, it actually is an action of the General Assembly," Cupit said at the meeting.

She added: "I got an opinion from the attorney general's office back in March saying that it's not the responsibility of the board, that it's the responsibility of the General Assembly."

Rolband asked Cupit to provide him with a copy of it, and she said she would.

The Richmond Times-Dispatch asked Cupit after the meeting for a copy of what the attorney general sent her; she said she'd check to see if she could release it, but never responded.

Victoria LaCivita, a spokeswoman for the attorney general, said by email for this story that there had been "no official or unofficial AG's opinion on RGGI issued by this administration."

But pressed as to whether the attorney general's office provided Cupit with anything in writing, a special counsel in the office, Stephanie Hamlett, said there was a document. She said the attorney general declined to release it, and she cited a discretionary FOIA exemption for written advice of legal counsel.

Womack, the DEQ staffer, declined to explain the circumstances under which someone at DEQ had the document "at one point" but no longer did.

Womack also responded last week on behalf of Cupit, the air board member, saying Cupit was opting not to release the document. Womack cited the discretionary FOIA exemption for legal advice.

Nothing in the Freedom of Information Act stops the attorney general's office or Cupit from releasing the document, but FOIA allows them to withhold it, at their discretion.

So for now, the mystery of the secret air board document remains unsolved.

Under RGGI, the revenue Virginia gets is directed to programs that help low-income people reduce energy usage — thereby lowering their cost of electricity — and for programs combating sea level rise in coastal areas and inland flooding across the state.

Under the initial RGGI cost recovery request from Dominion Energy, the state's largest electric utility, a typical customer's bill increased $2.39 a month because of the program.

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By Patrick Wilson

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Attachment 30

Table 3. 2020 State energy-related carbon dioxide emissions by sector

State	million metric tons of energy-related carbon dioxide						shares				
	Commercial	Electric Power	Residential	Industrial	Transportation	Total	Commercial	Electric Power	Residential	Industrial	Transportation
Alabama	2.1	42.7	1.9	18.0	33.6	98.3	2.1%	43.4%	1.9%	18.3%	34.2%
Alaska	2.1	2.7	1.7	17.6	11.9	36.0	5.9%	7.6%	4.6%	48.9%	33.0%
Arizona	2.8	35.6	2.6	4.7	34.4	80.1	3.6%	44.4%	3.2%	5.9%	43.0%
Arkansas	3.3	22.6	1.9	8.4	18.6	54.7	6.1%	41.2%	3.5%	15.3%	34.0%
California	18.4	33.6	26.6	64.3	160.4	303.4	6.1%	11.1%	8.8%	21.2%	52.9%
Colorado	4.3	28.6	8.5	12.9	25.6	79.9	5.4%	35.8%	10.6%	16.2%	32.0%
Connecticut	3.8	8.7	6.6	1.7	13.0	33.8	11.3%	25.6%	19.5%	4.9%	38.6%
Delaware	1.0	1.8	0.9	3.9	4.9	12.5	8.1%	14.5%	7.0%	31.1%	39.4%
District of Columbia	0.9	0.0	0.6	0.0	0.9	2.4	36.4%	0.0%	25.7%	1.0%	36.9%
Florida	6.5	92.3	1.4	11.2	96.3	207.6	3.2%	44.4%	0.7%	5.4%	46.4%
Georgia	4.4	37.3	7.1	11.7	56.1	116.6	3.8%	32.0%	6.0%	10.1%	48.1%
Hawaii	0.5	5.9	0.1	0.9	7.6	14.9	3.2%	39.3%	0.4%	5.9%	51.1%
Idaho	1.6	1.6	2.0	3.4	10.8	19.4	8.1%	8.5%	10.2%	17.5%	55.7%
Illinois	13.7	42.6	23.4	35.5	54.6	169.9	8.1%	25.1%	13.8%	20.9%	32.1%
Indiana	5.6	63.1	8.3	41.4	35.9	154.3	3.6%	40.9%	5.4%	26.9%	23.3%
Iowa	4.0	16.2	5.2	21.4	18.9	65.7	6.1%	24.7%	7.9%	32.5%	28.7%
Kansas	2.7	19.8	4.0	13.8	17.5	57.8	4.6%	34.3%	6.8%	23.9%	30.3%
Kentucky	2.6	50.5	3.0	14.1	31.8	101.9	2.6%	49.5%	2.9%	13.8%	31.2%
Louisiana	2.3	27.5	1.9	112.5	39.1	183.3	1.2%	15.0%	1.0%	61.4%	21.3%
Maine	1.6	0.7	2.9	1.7	6.6	13.5	12.0%	5.2%	21.2%	12.4%	49.2%
Maryland	5.2	9.2	5.5	2.7	25.5	48.1	10.8%	19.2%	11.5%	5.5%	53.1%
Massachusetts	7.3	5.7	12.2	3.1	24.0	52.3	13.9%	11.0%	23.3%	6.0%	45.8%
Michigan	10.7	47.0	19.6	15.9	43.6	136.8	7.8%	34.3%	14.3%	11.7%	31.9%
Minnesota	6.7	19.2	9.2	16.2	27.1	78.4	8.5%	24.5%	11.8%	20.6%	34.6%
Mississippi	1.6	26.3	1.4	11.5	22.4	63.1	2.5%	41.6%	2.3%	18.1%	35.5%
Missouri	4.4	54.8	6.4	8.3	34.9	108.7	4.0%	50.4%	5.9%	7.6%	32.1%
Montana	1.7	10.1	1.8	4.7	8.0	26.2	6.4%	38.5%	6.8%	17.8%	30.5%
Nebraska	2.2	19.6	2.5	9.0	13.2	46.5	4.7%	42.2%	5.4%	19.3%	28.4%
Nevada	2.0	13.3	2.7	2.8	15.5	36.2	5.5%	36.6%	7.4%	7.6%	42.8%
New Hampshire	1.3	1.6	2.8	0.8	6.0	12.4	10.7%	12.8%	22.3%	6.0%	48.1%
New Jersey	9.0	13.6	14.0	8.1	39.1	83.8	10.7%	16.2%	16.7%	9.7%	46.6%
New Mexico	1.7	18.6	2.3	7.7	14.9	45.2	3.8%	41.1%	5.1%	17.0%	33.0%
New York	20.3	23.4	31.5	8.0	60.1	143.4	14.2%	16.4%	22.0%	5.6%	41.9%
North Carolina	4.9	37.1	4.8	9.6	50.1	106.5	4.6%	34.8%	4.5%	9.0%	47.0%
North Dakota	1.3	27.4	1.0	16.0	8.5	54.3	2.4%	50.6%	1.9%	29.5%	15.6%
Ohio	11.6	67.0	17.1	34.9	55.0	185.6	6.3%	36.1%	9.2%	18.8%	29.7%
Oklahoma	3.1	24.7	3.8	23.2	28.8	83.7	3.7%	29.5%	4.6%	27.7%	34.4%
Oregon	2.4	8.9	2.8	4.4	19.1	37.5	6.3%	23.7%	7.5%	11.6%	50.8%
Pennsylvania	10.7	70.1	17.8	42.0	52.6	193.2	5.6%	36.3%	9.2%	21.8%	27.2%
Rhode Island	0.8	3.2	1.9	0.6	3.3	9.8	8.2%	32.4%	19.2%	6.2%	34.0%
South Carolina	2.2	22.8	1.9	7.1	29.5	63.5	3.4%	36.0%	3.0%	11.2%	46.4%
South Dakota	0.9	2.3	1.1	4.1	6.6	14.9	5.9%	15.3%	7.1%	27.6%	44.3%
Tennessee	3.9	19.7	4.0	13.8	41.9	83.3	4.7%	23.7%	4.8%	16.5%	50.3%
Texas	13.1	176.9	12.1	229.2	192.7	624.0	2.1%	28.3%	1.9%	36.7%	30.9%
Utah	2.9	26.4	4.2	6.6	17.2	57.4	5.1%	46.1%	7.4%	11.6%	29.9%
Vermont	0.9	0.0	1.4	0.5	2.6	5.4	16.3%	0.1%	26.2%	8.8%	48.7%
Virginia	5.7	28.8	5.8	10.8	47.1	98.2	5.8%	29.3%	5.9%	11.0%	48.0%
Washington	4.6	11.0	5.8	12.3	34.6	68.4	6.8%	16.1%	8.5%	18.0%	50.6%
West Virginia	1.6	50.4	1.7	12.0	11.2	76.9	2.1%	65.5%	2.2%	15.6%	14.6%
Wisconsin	6.1	31.5	9.8	12.2	27.4	87.0	7.0%	36.2%	11.2%	14.0%	31.5%
Wyoming	0.9	35.2	0.9	11.2	7.3	55.6	1.7%	63.4%	1.7%	20.2%	13.1%
Total[1]	235.8	1,439.8	320.1	948.3	1,648.5	4,592.4	5.1%	31.4%	7.0%	20.6%	35.9%

Data source: U.S. Energy Information Administration (EIA), State Energy Data System and EIA calculations made for this analysis.

[1]For the United States as a whole see, EIA, Monthly Energy Review, Section 11: Environment. Differing methodologies between the two data series causes the total for all states to be different from the national-level estimate.

Attachment 31

Photo by Katherine Hafner

Flooding in the Hague area of Norfolk in May 2022.

Unchecked sea level rise would cost Virginia $79 billion this century, ODU says

Written by Katherine Hafner (/staff/katherine)Published: 15 September 2022
Category: Local News (/news/local-news)

(https://www.facebook.com/sharer/sharer.php?u=https://whro.org/news/local-news/32263-unchecked-sea-level-rise-would-cost-virginia-79-billion-this-century-odu-says&caption=whro.org&title=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says&text=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says) (https://twitter.com/intent/tweet?via=WHRO&url=https://whro.org/news/local-news/32263-unchecked-sea-level-rise-would-cost-virginia-79-billion-this-century-odu-says&text=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says)

PLAY

The impacts of large natural disasters — think fires and hurricanes — are pretty easy to demonstrate.

But the injury from sea level rise can be harder to illustrate, said Bob McNab, director of Old Dominion University's Dragas Center for Economic Analysis and Policy.

Changes happen over months and years rather than all at once.

"You just kind of adjust slowly as the climate changes," McNab said. "And that's why it's harder to combat."

So how to grab people's attention on the issue? Follow the money.

That's what a new ODU analysis tries to do. Researchers estimated exactly how much coastal Virginia could lose if nothing changes to confront sea level rise and flooding.

They came up with some massive figures, expressed in 2021 dollars.

Unmitigated flooding from 2020 to 2099 would result in about $56 billion in financial damages — about 85% of which is in Hampton Roads, according to the new report.

That would lead to a roughly $79 billion decline in economic output across the Commonwealth's coast.

"Imagine a hurricane hitting Virginia last year and wiping out more than 13% of economic activity in Virginia," McNab said. "That's the cost we project in sea level rise and recurrent flooding over the remainder of the century."

To reach those numbers, the researchers looked at eight planning districts that comprise coastal Virginia, including Hampton Roads.

George McLeod, director of the Center for Geospatial Science, Education and Analytics said his team used modeling that builds upon their existing work.

They have spent years projecting (https://www.pilotonline.com/news/environment/vp-nw-odu-flood-map-20211221-ll2ikzcwfzfrvdi2cgm6bq3c2y-

story.html) how much flooding the region will see by 2040, 2060 and 2080 – down to the street level (https://odu-geosea.maps.arcgis.com/home/webmap/viewer.html?webmap=36e758f7e2b544a980962faef1faaeb4#).

According to data from the National Oceanic and Atmospheric Administration, average sea levels in Virginia could rise by almost 5 feet by the end of the century – even more in certain spots around the region.

One difference for this project is it includes projections for storm surge in addition to regular nuisance flooding, McLeod said.

His team used the models combined with basic economic numbers from various categories including agriculture, government and education.

“The way I look at it is, because of the complexity and magnitude and inevitability of this issue of sea level rise, it’s really our job to look at the problem at all scales,” McLeod said.

“It’s really incumbent upon us to look at every one of those scales and to try to provide as much information to decision-makers as possible.”

McNab then did further economic analysis, which does not take into account future mitigation efforts like a planned floodwall in Norfolk.

The Hampton Roads region would suffer the most economic consequences: $47 billion in direct losses leading to $67 billion in lost output.

That’s a conservative estimate, McNab said.

McNab and McLeod said they hope people will use the report to jumpstart both policy and grassroots efforts.

“This should be another part of the wake-up call for not only Virginia but coastal areas in the United States, because sea level rise is occurring,” McNab said. “These

are all the conversations that will become part and parcel of local, state and national politics over the coming decades."

(https://www.facebook.com/sharer/sharer.php?u=https://whro.org/news/local-news/32263-unchecked-sea-level-rise-would-cost-virginia-79-billion-this-century-odu-says&caption=whro.org&title=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says&text=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says)

(https://twitter.com/intent/tweet?via=WHRO&url=https://whro.org/news/local-news/32263-unchecked-sea-level-rise-would-cost-virginia-79-billion-this-century-odu-says&text=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says)

(/news/local-news/32302-foodbank-opens-western-tidewater-branch-to-combat-growing-food-insecurity)

(/news/local-news/32217-the-virginia-board-of-censors-operated-for-40-years-requiring-edits-to-thousands-of-films)

Attachment 32

As flooding risks increase, this small town in Appalachia is working on a flood mitigation plan

RADIO IQ | By Roxy Todd

Published November 23, 2022 at 5:14 AM EST

LISTEN • 3:36

Photo Courtesy WDBJ7 / Https://Www.Wdbj7.Com/Content/Misc/Flooding-In-Pulaski-569590501.Html

Flooding in April 2020 from Peak Creek pushed water onto East Main Street in Pulaski.

Scientists predict that flooding events will become more common, due to climate change, and communities in Appalachia are particularly vulnerable. The small town of Pulaski, in the New River Valley, is responding, by creating a plan to withstand the worst impacts of flooding.

On a clear, fall morning, Cathy Hanks is standing on a walking trail beside Peak Creek.

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In 2020 for example, the creek flooded several times.

“We had several 100 year floods in one month. You can see where this is being eaten away,” said Hanks, the President of a local activist group, Friends of Peak Creek.

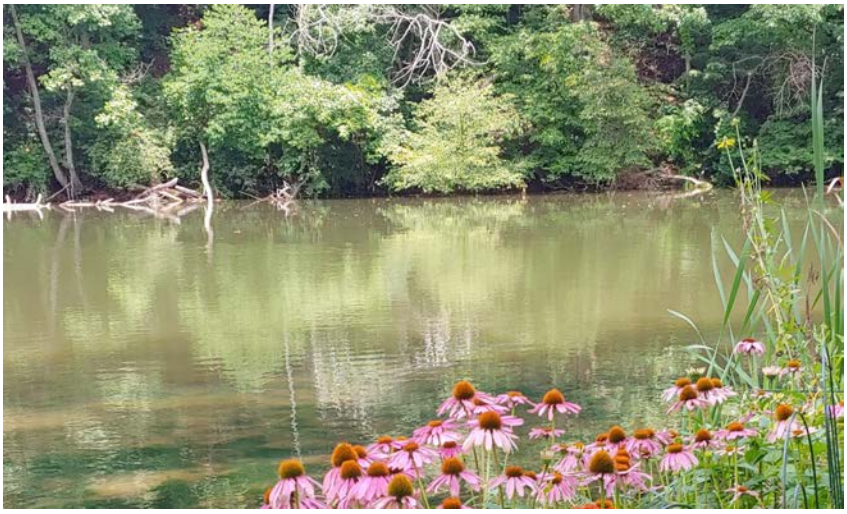
The bank along the creek is eroding, including at the edge of a former EPA Superfund site, a factory that used to make sulfuric acid. The site was contained by the EPA in the early 2000s, but Hanks and others wonder if repeated floods are bringing contaminants into the creek.

“Our concern is, it’s right beside the creek and there’s still erosion over there.”

Testing in 2019 by a student researcher at Virginia Tech revealed that heavy metals are present in the water and sediment near the site.

The Virginia Department of Environmental Quality has added portions of the creek to its list of impaired waters for high levels of several metals and chemicals, as well as e-coli.

To address these issues, as well as the flooding along the creek, in 2013 Hanks and other residents formed a local group called Friends of Peak Creek (FOPC). They also do beautification projects along the creek and organize clean up events to collect trash from the water.



Courtesy Friends Of Peak Creek /

Peak Creek

FOPC partnered with the New River Conservancy, and the town of Pulaski, to collect

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Council in February, 2021.

Part of the plan outlines steps that could clean up the contamination in the creek. It was submitted to the EPA, and the agency may provide funding for cleanup if the plan is approved.

Another part of the plan was sent to the Army Corps of Engineers (USACE) to help widen the creek and prevent erosion. According to Darlene Burcham, Pulaski town manager, the USACE has said that it will provide funds to do some of the flood mitigation work.

Applying for aid from the federal government to implement these types of plans isn't easy, and it's expensive. First, a community has to establish proof from engineers that it's necessary.

A team of faculty and students from Virginia Tech's Department of Biological Systems Engineering provided some assistance for free. They collected water and sediment quality data before and after rainfall events to see what the impacts of flooding were.

"They're just kind of stuck because they built this town right next to the creek. And it floods, and there's almost no way to stop that," said Cully Hession, an engineering professor at Virginia Tech.

He says relocating homes closest to the flood zone is one solution. Another is rebuilding the banks that erosion has eaten away.

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Peak Creek in downtown Pulaski

“Pulaski is one of our favorite places to work. Because they have a really great citizen’s group, and the town engineer reached out,” said Leigh Anne Krometis, another engineering professor who was on the team that assisted with the flood mitigation plan. She said sometimes communities get into disputes when it comes to addressing environmental and public health issues, but Pulaski worked together on the project in a collaborative way.

Back at the pedestrian path, Hanks points to one place they’ve recently done some restoration work themselves. Near a playground along the banks of one of the tributaries that flows into Peak Creek, the town partnered with FOPC and the New River Conservancy to plant bushes and native plants, like willow, elderberry and silky dogwood.

The vegetation can’t prevent flooding, but it can reduce erosion. And in a bad flood, the plants can help slow the water. “People don’t understand that this is healthy. Pretty is not necessarily healthy,” Hanks said.

The playgrounds and parks near the creek will continue to flood, a situation that's inevitable,. And it's one that many communities are grappling with.

Pulaski is working to stay ahead of the risk by developing a plan and taking steps to act on it. But it will take time, and a lot of money, to prevent the worst damage from flooding.

“This is gonna take years,” Hanks said. “Years and years to do, to implement plans to protect the creek.”

Tags News | Local News | Pulaski | Climate Change | Flooding

Roxy Todd

Roxy Todd is Radio IQ's New River Valley Bureau Chief.

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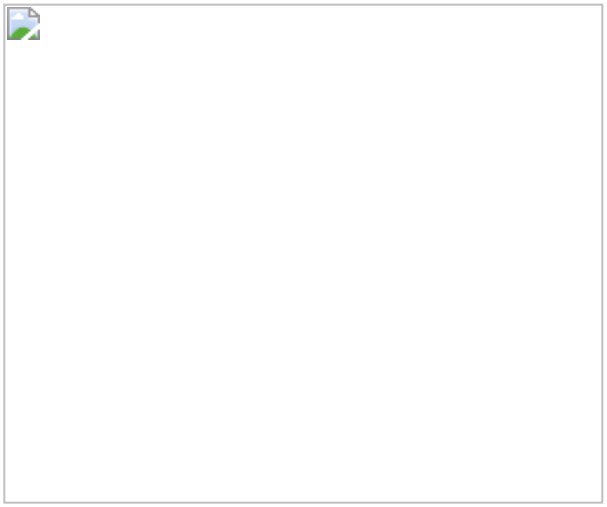

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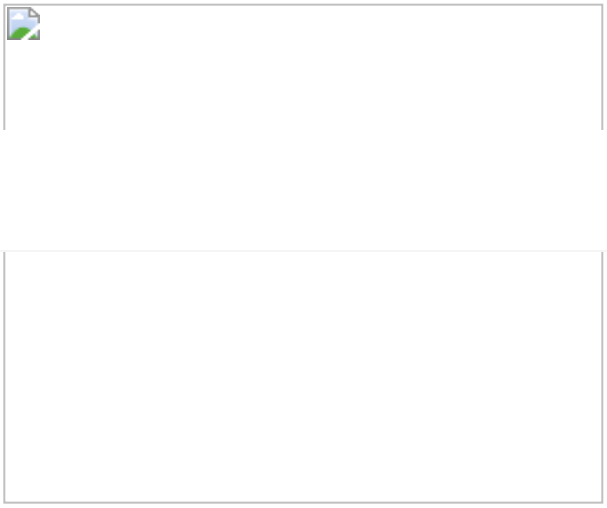

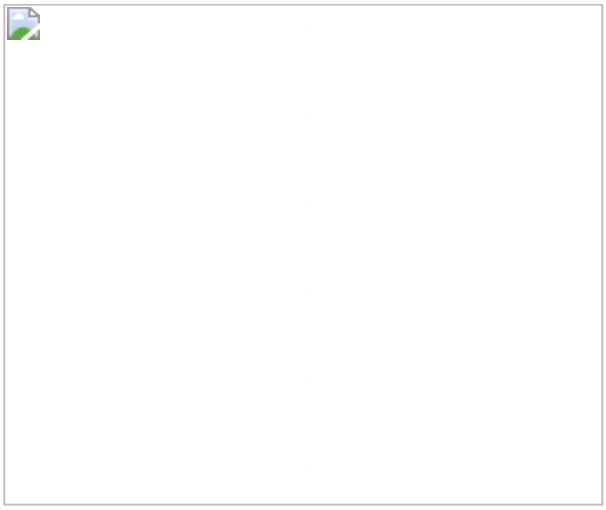

A podcast exploring how society confronts sin

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Attachment 33

As floods worsen in Appalachia, disaster prep gets more complex — and necessary

by **Molly Born**
September 16, 2021

Drone footage of Powell County, Ky., on March 1, 2021, following historic flooding. Courtesy of Jason Rose.

As climate change leads to more intense flooding, communities will need to make crucial — and creative — investments to protect themselves.

On the evening of Feb. 28, Kevin Babcock watched as rain fell across the Eastern Appalachian Mountains, threatening to send the Red River in Powell County, Ken., over its banks. The water came fast, and without much warning, causing record flooding in parts of eastern and central Kentucky. The state's network of environmental monitoring stations, Kentucky Mesonet, helps local emergency managers like Babcock prepare by tracking temperature, precipitation, and historical weather data in 76 locations across the state.

However, Powell is one of several eastern counties without this technology. So, Babcock and other officials must rely on reports from other parts of the state to make predictions that inform critical decisions such as whether to issue an evacuation order.

During the floods in late February, estimates coming from the National Weather Service's Jackson County location — more than 50 miles away — offered the best determination of how high the river might get. "We're basically in a little valley by ourselves," said Babcock, "I didn't want to go to sleep if the river was rising rapidly."

Around 3:30 a.m. on March 1, Babcock received notice that the predictions in Powell were underestimated by up to four feet: The river, normally between 8 and 12 feet deep, topped out at more than 25. More than 300 families left their homes after the flood warning was issued on Feb. 28, but "the speed and uncertainty of the flooding" led to nearly 100 water rescues, Babcock said.

Babcock said this marked the second-highest crest in modern history. Drone **footage** showed washed out roads; homes and businesses were partially underwater. Floodwaters inundated a fifth of the county, led to dozens of rescues, and cut off the county's second most populous town for days.

"Since 1978 we've had five 40-year floods," Babcock said of Powell County. "That's not right, that's not normal."

A monitoring station closer to Powell could save lives, Babcock insisted, and he applied for a hazard mitigation grant from the Federal Emergency Management Agency (FEMA) that would fund the purchase of one for around $50,000.

"In the old days I used to rely on animals [that] moved to high ground," Babcock said of the way he used to predict flooding. "We don't need to do that. We have actual technology that could help us," he said.

But other experts suggest the money could be better spent elsewhere.

Nicolas Zegre, associate professor of forest hydrology and director of West Virginia University's Mountain Hydrology Laboratory, noted that while forecasts can be useful, they can also be wrong. He suggested that the $50,000 could go toward paying a team to work with residents to map evacuation routes, develop in-home emergency preparedness plans, and gather examples of community resilience in past disasters.

"The most important thing we can do about this is talk about this," Zegre said. "Nothing is going to happen until there's public discourse around this. And after we have public discourse, that's what then influences our elected decision makers to act."

While experts may disagree about the best response, the last few years, in particular, demonstrate the peril of flooding in Appalachia.

Kentucky's interim climatologist, Megan Schargorodski, called what happened in the state earlier this year a "combination event" because the ground was still saturated from the winter, making drainage even more difficult. In eastern Kentucky especially, "it's a huge problem because there's nowhere for the water to go," she said.

In mountainous states like the ones that make up Appalachia, heavy rain will run off hillsides, soaking the valleys beneath, and unlike the sandy soils of coastal states, clay-heavy soil found in **parts** of the Southern Appalachians drains water slowly. As West Virginia state climatologist Kevin Law told *Southerly*, five inches of rain in West Virginia might be more devastating than it would be in Florida. Flooding can be exacerbated, too, by the dangerous conditions in **parts of the region damaged by coal mining**: Strip mine sites can increase erosion and stream flow, leading to landslides.

The flooding in Kentucky is part of a pattern that other parts of the South are also seeing as climate change leads to more intense precipitation. That will likely continue, according to the latest **Intergovernmental Panel on Climate Change assessment**. In August, four people died about 45 minutes west of Asheville, N.C. after flooding caused by Tropical Storm Fred. Days later, 17 inches of water fell in a single day in middle Tennessee, causing flash flooding that killed at least 22 people. Hurricane Ida hit the Gulf Coast as a Category 4 storm, which caused **minor flooding** in West Virginia, but caused deadly floods a few states north.

Law, who is also a professor at Marshall University, has been studying how hurricanes making landfall are causing heavier rain inland, "possibly stalling out and dumping more rainfall in the Appalachian Mountains." Law said it'd "definitely be advantageous" to have a more robust weather monitoring network in West Virginia, "especially in flood prone areas like the southwestern coalfields. We just don't really have a whole lot of stations down there," he added.

Parts of central Appalachia, including southwest Virginia, eastern Kentucky, and West Virginia, have been drenched in recent years by floods, some deadly. According to West Virginia University, more than 700 floods have occurred across the state since 2016, costing the state billions. In **February 2020,** heavy rains caused flooding and mudslides in southeastern Kentucky, sending trailers downstream and resulting in one death when a man was found dead in his car after he drove into flood waters. In West Virginia, flooding is "the most frequent and devastating disaster threatening" the state, according to its hazard mitigation plan, which was last updated in 2018. In June 2016, **23 people died** and thousands of homes and businesses were damaged when up to 10 inches of rain fell in less than 12 hours—one of the deadliest floods in the state's history.

People get caught off guard because they're not prepared, said Zegre, noting that "historically, the likelihood of something big happening to any given person at any given time was less." With more frequent, intense

weather events, that is changing. And while flooding is relevant while it's happening, he continues, the more time passes "the less important it becomes to our day-to-day."

"That memory is only going to become relevant if we talk about it and we keep the memory fresh," through activities like community forums and storytelling. "But that has to be intentional. And that really doesn't happen the way it needs to," Zegre said.

With a group of colleagues, Zegre explored this idea in a recent analysis for the journal **Frontiers in Water**, asserting that scientific experts should be "on equal footing" with residents in communities vulnerable to flooding. For her part, Jamie Shinn, WVU assistant professor of geography, brings a camera and recorder during interviews with survivors of the 2016 floods in Rainelle, West Virginia, to document their stories.

Among the authors most "critical" findings in the recent analysis: Drainage infrastructure, especially culverts, should be upgraded; communities should be better prepared through education; and the institutions overseeing flood preparation and response should be better run.

"They themselves are experts in their lived experience and they know what they need," Zegre said. "Simply throwing money from the federal government down is a good start, but it's not the end and it's barely beginning."

Then there's the familiar sense that for one person "it's hella overwhelming and complex" to consider how to affect change, Zegre said.

"At the individual level, it's really overwhelming. It's scary. It seems like there isn't a solution. And I think it's kind of the human brain to not focus on it, especially when it's not happening all the time," he said.

Last year First Street Foundation, a nonprofit group of hydrologists, researchers and data scientists, found that several Appalachia counties may be much more at risk of major flooding than FEMA predictions show. A 2021 analysis found that West Virginia, Kentucky, and Ohio share "a significant amount of risk" of economic damage "driven by heavy precipitation and small waterway flooding."

FEMA has warned property owners about these risks as far back as 2010. In an advisory from that year, the agency stated: "The next time you hear hurricane — think inland flooding!" According to the National Oceanic and Atmospheric Administration, roughly a quarter of U.S. hurricane deaths between 1963 and 2012 occurred in inland counties, and half were related to freshwater flooding.

A federal disaster declaration following the Kentucky floods in late February unlocked millions in FEMA aid as hundreds of residents grappled with damage to homes and businesses — and the reality that yet another devastating flood had left its mark on the region.

This summer FEMA announced three ambitious "pre-disaster funding opportunities" including nearly $3.5 billion in hazard mitigation grants that states can use to protect against future catastrophes. That money covers three-quarters of total project costs and states or communities; Kentucky, for instance, will get $22 million for plans the state has reviewed and submitted to FEMA for funding in 2022.

"The real goal of mitigation is to reduce future damages," said David Vandewater, a FEMA program manager for hazard mitigation assistance grants, covering Florida, Tennessee, and Kentucky.

The influx of cash supports FEMA's existing hazard mitigation grant program, which began in the late 1980s to fund projects like retrofitting a building to improve its wind resistance, upgrading drainage systems, or purchasing a weather monitoring station like the one Babcock is seeking, among other plans. One major hazard mitigation grant project in recent years in Kentucky included the construction of a drainage basin with new culverts in Lexington. (The city had to cover just $273,000 of the $2.1 million project.)

Communities are responsible for developing a project plan that must be approved by the state and FEMA before the agency will release funding. Even applying can be a delicate process. In a 2010 **video**, the University of Kentucky's hazard mitigation planning manager, who assists communities applying for grants, said project requests typically need reworking to include "FEMA language" that "maybe people out in the communities don't know."

By their design, hazard mitigation grants give states wide latitude to green-light projects. But the recent Frontiers in Water study of the aftermath of the 2016 flood in West Virginia suggests why that could be problematic. West Virginia's institutions responsible for minimizing flood risks, for example, might be considered "weak" because of "policies that prioritize resource extraction-based political agenda," the report reads. Notably, officials have taken "little-to-no action" on the plan developed by the state's Flood Protection Task Force, according to the 2016 report.

"Strong institutions necessary to coordinate and develop community information through local floods and hazard maps, evacuation routes, and safe zones are absent. Hence, disaster preparedness stymied by weak institutional governance results in high hazards leading to greater vulnerability," the report reads.

In Kentucky, Babcock is still waiting for final approval from FEMA for the Mesonet weather monitoring station in Powell County, which the county applied for in response to flooding in early 2019.

"It is good to know that they make sure of the needs with the limited funds available," he said, "but it would help to be faster."

Molly Born is Southerly's Appalachia correspondent. If you have ideas about what she should be covering in Appalachia, or you want to tell your flood story, ***fill out this form.***

Attachment 34

Model Rule
Part XX CO_2 Budget Trading Program
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Subpart XX-1 CO_2 Budget Trading Program General Provisions

XX-1.1 Purpose.

This Part establishes the NAME OF RELEVANT RGGI STATE component of the CO_2 Budget Trading Program, which is designed to reduce anthropogenic emissions of CO_2, a greenhouse gas, from CO_2 budget sources in an economically efficient manner.

XX-1.2 Definitions.

Account Number. The identification number given by the REGULATORY AGENCY or its agent to each CO_2 Allowance Tracking System account.

Acid rain emissions limitation. As defined in 40 CFR 72.2, a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program under title IV of the Clean Air Act.

Acid Rain Program. Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and 40 CFR Parts 72 through 78.

Administrator. Administrator means the Administrator of the United States Environmental Protection Agency or the administrator's authorized representative.

Allocate or allocation. The determination by the REGULATORY AGENCY of the number of CO_2 allowances to be recorded in the compliance account of a CO_2 budget unit, an allocation set-aside account, the consumer benefit or strategic energy purpose account, or the general account of the sponsor of an approved CO_2 emissions offset project.

[The reference to the consumer benefit or strategic energy purpose account illustrates how this account could be labeled and does not necessarily represent what an individual RGGI State will propose.]

Allocation year. A calendar year for which the REGULATORY AGENCY allocates or awards CO_2 allowances pursuant to Subparts XX-5 and XX-10. The allocation year of each CO_2 allowance is reflected in the unique identification number given to the allowance pursuant to subdivision XX-6.4(c).

Allowance auction or auction. An auction in which the REGULATORY AGENCY or its agent offers CO_2 allowances for sale.

Attribute. A characteristic associated with electricity generated using a particular renewable fuel, such as its generation date, facility geographic location, unit vintage, emissions output, fuel, state program eligibility, or other characteristic that can be identified, accounted for, and tracked.

Attribute credit. An attribute credit represents the attributes related to one megawatt-hour of electricity generation.

Automated Data Acquisition and Handling System (DAHS). That component of the continuous emissions monitoring system, or other emissions monitoring system approved for use under Subpart XX-8, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by Subpart XX-8.

Award. The determination by the REGULATORY AGENCY of the number of CO_2 offset allowances to be recorded in the general account of a project sponsor pursuant to XX-10.7. Award is a type of allocation.

Billing Meter. To qualify as a billing meter, the measurement device must be used to measure electric or thermal output for commercial billing under a contract. The facility selling the electric or thermal output must have different owners from the owners of the party purchasing the electric or thermal output.

Boiler. An enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

CO_2 allowance. A limited authorization by the REGULATORY AGENCY or a participating state under the CO_2 Budget Trading Program to emit up to one ton of CO_2, subject to all applicable limitations contained in this Part.

CO_2 allowance deduction or deduct CO_2 allowances. The permanent withdrawal of CO_2 allowances by the REGULATORY AGENCY or its agent from a CO_2 Allowance Tracking System compliance account to account for the number of tons of CO_2 emitted from a CO_2 budget source for a control period or an interim control period, determined in accordance with Subpart XX-8, or for the forfeit or retirement of CO_2 allowances as provided by this Part.

CO_2 allowances held or hold CO_2 allowances. The CO_2 allowances recorded by the REGULATORY AGENCY or its agent, or submitted to the REGULATORY AGENCY or its agent for recordation, in accordance with Subparts XX-6 and XX-7, in a CO_2 Allowance Tracking System account.

CO_2 Allowance Tracking System (COATS). A system by which the REGULATORY AGENCY or its agent records allocations, deductions, and transfers of CO_2 allowances under the CO_2 Budget Trading Program. The tracking system may also be used to track CO_2 emissions offset projects, CO_2 allowance prices and emissions from affected sources.

CO_2 Allowance Tracking System account. An account in the CO_2 Allowance Tracking System established by the REGULATORY AGENCY or its agent for purposes of recording the allocation, holding, transferring, or deducting of CO_2 allowances.

CO_2 allowance transfer deadline. Midnight of the March 1 occurring after the end of the relevant control period and each relevant interim control period or, if that March 1 is not

a business day, midnight of the first business day thereafter and is the deadline by which CO_2 allowances must be submitted for recordation in a CO_2 budget source's compliance account in order for the source to meet the CO_2 requirements of XX-1.5(c) for the control period and each interim control period immediately preceding such deadline.

CO_2 authorized account representative. For a CO_2 budget source and each CO_2 budget unit at the source, the natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Subpart XX-2, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the natural person who is authorized, under Subpart XX-6, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program or CSAPR SO_2 Group 2 Trading Program then, for a CO_2 Budget Trading Program compliance account, this natural person shall be the same person as the designated representative as defined in the respective program.

CO_2 authorized alternate account representative. For a CO_2 budget source and each CO_2 budget unit at the source, the alternate natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Subpart XX-2, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the alternate natural person who is authorized, under Subpart XX-6, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program or CSAPR SO_2 Group 2 Trading Program then, for a CO_2 Budget Trading Program

compliance account, this alternate natural person shall be the same person as the alternate designated representative as defined in the respective program.

CO_2 budget emissions limitation. For a CO_2 budget source, the tonnage equivalent, in CO_2 emissions in a control period or an interim control period, of the CO_2 allowances available for compliance deduction for the source for a control period or an interim control period.

CO_2 budget permit. The portion of the legally binding permit issued by the REGULATORY AGENCY pursuant to **[Insert Reference to State's Permitting Regulation(s)]** to a CO_2 budget source or CO_2 budget unit which specifies the CO_2 Budget Trading Program requirements applicable to the CO_2 budget source, to each CO_2 budget unit at the CO_2 budget source, and to the owners and operators and the CO_2 authorized account representative of the CO_2 budget source and each CO_2 budget unit.

CO_2 budget source. A source that includes one or more CO_2 budget units.

CO_2 Budget Trading Program. A multi-state CO_2 air pollution control and emissions reduction program established pursuant to this Part and corresponding regulations in other states as a means of reducing emissions of CO_2 from CO_2 budget sources.

CO_2 budget unit. A unit that is subject to the CO_2 Budget Trading Program requirements under section XX-1.4.

CO_2 cost containment reserve allowance or CO_2 CCR allowance. A CO_2 allowance that is offered for sale at an auction by the REGULATORY AGENCY for the purpose of containing the cost of CO_2 Allowances. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base and adjusted

budgets. CO_2 CCR allowances are subject to all applicable limitations contained in this Part.

CO_2 cost containment reserve trigger price, or CCR trigger price. The CCR trigger price is the minimum price at which CO_2 CCR allowances are offered for sale by the REGULATORY AGENCY or its agent at an auction. The CCR trigger price shall be $10.00 per CO_2 allowance in calendar year 2017. Each calendar year thereafter through 2020, the CCR trigger price shall be 1.025 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent. The CCR trigger price in calendar year 2021 shall be $13.00. Each calendar year thereafter, the CCR trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 1.

Table 1. CO_2 CCR Trigger Price

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$10.25	$10.51	$10.77	$13.00	$13.91	$14.88	$15.92	$17.03	$18.22	$19.50	$20.87	$22.33	$23.89

CO_2 emissions containment reserve allowance or CO_2 ECR allowance. A CO_2 allowance that is withheld from sale at an auction by the REGULATORY AGENCY for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.

CO_2 emissions containment reserve trigger price, or ECR trigger price. The ECR trigger price is the price below which CO_2 allowances will be withheld from sale by the REGULATORY AGENCY or its agent at an auction. The ECR trigger price in calendar year 2021 shall be $6.00. Each calendar year thereafter, the ECR trigger price shall be 1.07 multiplied by the ECR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 2.

Table 2. CO_2 ECR Trigger Price

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$ 6.00	$ 6.42	$ 6.87	$ 7.35	$ 7.86	$ 8.41	$ 9.00	$ 9.63	$10.30	$11.02

CO_2 equivalent. The quantity of a given greenhouse gas multiplied by its global warming potential (GWP).

CO_2 offset allowance. A CO_2 allowance that is awarded to the sponsor of a CO_2 emissions offset project pursuant to section XX-10.7 and is subject to the relevant compliance deduction limitations of section XX-6.5(a)(3).

Combined cycle system. A system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

[This definition of CHP unit illustrates how this could be defined and does not necessarily represent what an individual RGGI State will propose]

Combined heat and power unit or CHP unit, (also known as "cogeneration"). An electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy facility.

Combustion turbine. An enclosed fossil or other fuel-fired device that is comprised of a compressor (if applicable), a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

Commence commercial operation. With regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. For a unit that is a CO_2 budget unit under

section XX-1.4 on the date the unit commences commercial operation, such date shall remain the unit's date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under section XX-1.4 on the date the unit commences commercial operation, the date the unit becomes a CO_2 budget unit under section XX-1.4 shall be the unit's date of commencement of commercial operation.

Commence operation. To begin any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber. For a unit that is a CO_2 budget unit under section XX-1.4 on the date of commencement of operation, such date shall remain the unit's date of commencement of operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under section XX-1.4 on the date of commencement of operation, the date the unit becomes a CO_2 budget unit under section XX-1.4 shall be the unit's date of commencement of operation.

Compliance account. A CO_2 Allowance Tracking System account, established by the REGULATORY AGENCY or its agent for a CO_2 budget source under Subpart XX-6, in which are held CO_2 allowances available for use by the source for a control period and each interim control period for the purpose of meeting the CO_2 requirements of XX-1.5(c).

[This definition for the consumer benefit or strategic energy purpose account illustrates how this account could be defined and does not necessarily represent what an individual RGGI State will propose.]

Consumer benefit or strategic energy purpose account. A general account established by the Regulatory Agency or its agent from which allowances will be sold or distributed in order to provide funds to encourage and foster the following: promotion of energy efficiency measures, direct mitigation of electricity ratepayer impacts attributable to the

implementation of the CO_2 Budget Trading Program, promotion of renewable or non-carbon-emitting energy technologies, stimulation or reward of investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and/or the administration of NAME OF RELEVANT RGGI STATE component of the CO_2 Budget Trading Program.

Continuous Emissions Monitoring System (CEMS). The equipment required under Subpart XX-8 to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated DAHS), a permanent record of stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with 40 CFR Part 75 and Subpart XX-8. The following systems are types of continuous emissions monitoring systems required under Subpart XX-8.

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A nitrogen oxides emissions rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2; and NO_X emissions rate, in pounds per million British thermal units (lb/MMBtu);

(3) A moisture monitoring system, as defined in 40 CFR 75.11(b)(2) and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated

data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period. The control period is a three-calendar-year time period. The first control period is from January 1, 2009 to December 31, 2011, inclusive. Each subsequent sequential three-calendar-year period is a separate control period. The first two calendar years of each control period are each defined as an interim control period, beginning on January 1, 2015.

Cross State Air Pollution Rule (CSAPR) NO_X Annual Trading Program. A multi-state NO_X air pollution control and emission reduction program established in accordance with subpart AAAAA of 40 CFR Part 97 and 40 CFR 52.38(a) (including such a program that is revised in a SIP revision approved by the Administrator under 40 CFR 52.38(a)(3) or (4) or that is established in a SIP revision approved by the Administrator under 40 CFR 52.38(a)(5)), as a means of mitigating interstate transport of fine particulates and NO_X.

Cross State Air Pollution Rule (CSAPR) NO_X Ozone Season Trading Program. A multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of 40 CFR Part 97 and 40 CFR 52.38(b) (including such a program that is revised in a SIP revision approved by the Administrator under 40 CFR 52.38(b)(3) or (4) or that is established in a SIP revision approved by the Administrator under 40 CFR 52.38(b)(5)), as a means of mitigating interstate transport of ozone and NO_X.

Cross State Air Pollution Rule (CSAPR) SO_2 Group 1 Trading Program. A multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart CCCCC of 40 CFR Part 97 and 40 CFR 52.39(a), (b), (d) through (f), (j), and (k)

(including such a program that is revised in a SIP revision approved by the Administrator under 40 CFR 52.39(d) or (e) or that is established in a SIP revision approved by the Administrator under 40 CFR 52.39(f)), as a means of mitigating interstate transport of fine particulates and SO_2.

Cross State Air Pollution Rule (CSAPR) SO_2 Group 2 Trading Program. A multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of 40 CFR Part 97 and 40 CFR 52.39(a), (c), and (g) through (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under 40 CFR 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under 40 CFR 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

Eligible biomass. Eligible biomass includes sustainably harvested woody and herbaceous fuel sources that are available on a renewable or recurring basis (excluding old-growth timber), including dedicated energy crops and trees, agricultural food and feed crop residues, aquatic plants, unadulterated wood and wood residues, animal wastes, other clean organic wastes not mixed with other solid wastes, biogas, and other neat liquid biofuels derived from such fuel sources. Sustainably harvested will be determined by the REGULATORY AGENCY.

Excess emissions. Any tonnage of CO_2 emitted by a CO_2 budget source during a control period that exceeds the CO_2 budget emissions limitation for the source.

Excess interim emissions. Any tonnage of CO_2 emitted by a CO_2 budget source during an interim control period multiplied by 0.50 that exceeds the CO_2 budget emissions limitation for the source.

First control period adjustment for banked allowances. An adjustment applied to the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget for allocation years 2014 through 2020 to address the surplus allocation year 2009, 2010,

and 2011 allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states.

Fossil fuel. Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired.

(1) With regard to a unit that commenced operation prior to January 1, 2005, the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 50 percent of the annual heat input on a Btu basis during any year.

(2) With regard to a unit that commenced or commences operation on or after January 1, 2005, the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 5 percent of the annual heat input on a Btu basis during any year.

General account. A CO_2 Allowance Tracking System account, established under Subpart XX-6, that is not a compliance account.

Global Warming Potential (GWP). A measure of the radiative efficiency (heat-absorbing ability) of a particular gas relative to that of carbon dioxide (CO_2) after taking into account the decay rate of each gas (the amount removed from the atmosphere over a given number of years) relative to that of CO_2. Global warming potentials used in this Part are consistent with the values used in the Intergovernmental Panel on Climate Change, Fifth Assessment Report.

Gross generation. The electrical output (in MWe) at the terminals of the generator.

Interim control period. An interim control period is a one-calendar-year time period, during each of the first and second calendar years of each three year control period. The first interim control period starts on January 1, 2015 and ends on December 31, 2015, inclusive. The second interim control period starts on January 1, 2016 and ends on December 31, 2016, inclusive. Each successive three year control period will have two interim control periods, comprised of each of the first two calendar years of that control period.

Life-of-the-unit contractual arrangement. A unit participation power sales agreement under which a customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and/or associated energy from any specified unit pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period equal to or greater than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum potential hourly heat input. An hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use appendix D of 40 CFR Part 75 to report heat input, this value should be calculated, in accordance with 40 CFR Part 75, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value should be reported, in accordance with 40 CFR Part 75, using the maximum potential flow rate and either the maximum carbon dioxide concentration (in percent CO_2) or the minimum oxygen concentration (in percent O_2).

Minimum reserve price. The minimum reserve price in calendar year 2014 shall be $2.00. Each calendar year thereafter, the minimum reserve price shall be 1.025 multiplied by the minimum reserve price from the previous calendar year, rounded to the nearest whole cent.

Monitoring system. Any monitoring system that meets the requirements of Subpart XX-8, including a continuous emissions monitoring system, an excepted monitoring system, or an alternative monitoring system.

NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget. The NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget is determined in accordance with section XX-5.3 and is the annual amount of CO_2 tons available in NAME OF RELEVANT RGGI STATE for allocation in a given allocation year, in accordance with the CO_2 Budget Trading Program. CO_2 offset allowances allocated to project sponsors and CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget.

NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program Base Budget. The NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is specified in section XX-5.1. CO_2 offset allowances allocated to project sponsors and CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program Base Budget.

Nameplate capacity. The maximum electrical output (in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other de-ratings as measured in accordance with the United States Department of Energy standards.

[This definition for Net-Electric Output illustrates how this could be defined and does not necessarily represent what an individual RGGI State will propose.]

Net-electric output. The amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Non-CO_2 budget unit. A unit that does not meet the applicability criteria of Section XX-1.4 of this Part.

Operator. Any person who operates, controls, or supervises a CO_2 budget unit or a CO_2 budget source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner. Any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a CO_2 budget unit; or

(2) Any holder of a leasehold interest in a CO_2 budget unit, other than a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the CO_2 budget unit; or

(3) Any purchaser of power from a CO_2 budget unit under a life-of-the-unit contractual arrangement in which the purchaser controls the dispatch of the unit; or

(4) With respect to any general account, any person who has an ownership interest with respect to the CO_2 allowances held in the general account and who is subject to the binding agreement for the CO_2 authorized

account representative to represent that person's ownership interest with respect to the CO_2 allowances.

Participating state. A state that has established a corresponding regulation as part of the CO_2 Budget Trading Program.

Receive or *receipt of*. When referring to the REGULATORY AGENCY or its agent, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the REGULATORY AGENCY or its agent in the regular course of business.

Recordation, record, or *recorded*. With regard to CO_2 allowances, the movement of CO_2 allowances by the REGULATORY AGENCY or its agent from one CO_2 Allowance Tracking System account to another, for purposes of allocation, transfer, or deduction.

Reserve price. The minimum acceptable price for each CO_2 allowance in a specific auction. The reserve price at an auction is either the minimum reserve price or the CCR trigger price, as specified in Subpart XX-9.

Second control period adjustment for banked allowances. An adjustment applied to the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget for allocation years 2015 through 2020 to address the allocation year 2012 and 2013 allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states, that are in addition to the aggregate quantity of 2012 and 2013 emissions from all CO_2 budget sources in all of the participating states.

Serial number. When referring to CO_2 allowances, the unique identification number assigned to each CO_2 allowance by the REGULATORY AGENCY or its agent under

section XX-6.4(c).

Source. Any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any air pollutant. A source, including a source with multiple units, shall be considered a single facility.

State. A State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands.

Submit or *serve*. To send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service;

(3) By other means of dispatch or transmission and delivery.

Compliance with any "submission," "service," or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Third adjustment for banked allowances. An adjustment applied to the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget for allocation years 2021 through 2025 to address allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states, that are in addition to the aggregate quantity of emissions from all CO_2 budget sources in all of the participating states at the end of the fourth control period in 2020 and as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

Ton or *tonnage.* Any "short ton", or 2,000 pounds. For the purpose of determining compliance with the CO_2 requirements of XX-1.5(c), total tons for a control period and each interim control period shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in

accordance with Subpart XX-8, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons. A short ton is equal to 0.9072 metric tons.

Undistributed CO_2 allowances. CO_2 allowances originally allocated to a set aside account as pursuant to XX-5.3 that were not distributed.

Unit. A fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

Unit operating day. A calendar day in which a unit combusts any fuel.

Unsold CO_2 allowances. CO_2 allowances that have been made available for sale in an auction conducted by the REGULATORY AGENCY or its agent, but not sold.

Voluntary renewable energy purchase. A purchase of electricity from renewable energy generation or renewable energy attribute credits by a retail electricity customer on a voluntary basis. Renewable energy includes electricity generated from biomass, wind, solar thermal, photovoltaic, geothermal, hydroelectric facilities certified by the Low Impact Hydropower Institute, wave and tidal action, and fuel cells powered by renewable fuels. The renewable energy generation or renewable energy attribute credits related to such purchases may not be used by the generator or purchaser to meet any regulatory mandate, such as a renewable portfolio standard.

[The above subdivision is an optional definition that complements the optional voluntary renewable energy market set-aside provision at XX-5.3(d).]

XX-1.3 Measurements, abbreviations and acronyms.

Measurements, abbreviations, and acronyms used in this Part are defined as follows:

(1) CO_2: carbon dioxide.

(2) hr: hour.

(3) lb: pounds.

(4) MMBtu: one million British thermal units

(5) MW: megawatt

(6) MWe: megawatt electrical.

(7) MWh: megawatt hours

XX-1.4 Applicability.

(a) *Units.* Any unit that, at any time on or after January 1, 2005, serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe shall be a CO_2 budget unit, and any source that includes one or more such units shall be a CO_2 budget source, subject to the requirements of this Part.

[The following subdivision is optional. The text of this subdivision illustrates how a participating state might provide for an exemption for units with electrical output to the electric grid restricted by permit conditions. Upon exemption, the tons attributable to sources in a state's initial inventory shall be removed the state's budget under Section XX-5.3.]

(b) *Limited exemption for units with electrical output to the electric grid restricted by permit conditions*.

(1) *Applicability*. Notwithstanding subdivision (a) of this section, a unit under subdivision (a) of this section that has a permit containing a condition restricting the supply of the unit's annual electrical output to the electric grid to less than or equal to 10 percent of the annual gross generation of the unit, and which complies with the provisions in paragraph (b)(3) of this section, shall be exempt from the requirements of this Part, except for the provisions of this section, section XX-1.2, section XX-1.3, section XX-1.6 and, if applicable because of the allocation of CO_2 allowances during the pre-exemption time period, Subparts XX-5, XX-6 and XX-7.

(2) *Effective date*. The exemption under paragraph (b)(1) of this section shall

become effective as of the January 1 that is on or after the date on which the restriction on the percentage of annual gross generation that may be supplied to the electric grid and the provisions in the permit required under paragraph (b)(1) of this section become final.

(3) *Compliance.*

(i) A unit exempt under paragraph (b)(1) of this section shall comply with the restriction on percentage of annual gross generation that may be supplied to the electric grid described in paragraph (b)(1) of this section.

(ii) A unit exempt under paragraph (b)(1) shall report to the REGULATORY AGENCY the amount of annual gross generation and the amount of annual gross generation supplied to the electric grid during the year by the following February 1.

(iii) For a period of 10 years from the date the records are created, the owners and operators of a unit exempt under paragraph (b)(1) of this section shall retain, at the source that includes the unit, records demonstrating that the conditions of the permit under paragraph (b)(1) of this section were met. The 10-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the REGULATORY AGENCY. The owners and operators bear the burden of proof that the unit met the restriction on the percentage of annual gross generation that may be supplied to the electric grid.

(iv) The owners and operators and, to the extent applicable, the CO_2 authorized account representative of a unit exempt under paragraph (b)(1) of this section shall comply with all the requirements of this Part concerning all time periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(v) On the earlier of the following dates, a unit exempt under paragraph (b)(1) of this section shall lose its exemption:

(a) The date on which the restriction on the percentage of annual gross generation that may be supplied to the electric grid described in paragraph (b)(1) of this section is removed from the unit's permit or otherwise becomes no longer applicable in any year that commences on or after January 1, 2009; or

(b) The first date on which the unit fails to comply, or on which the owners and operators fail to meet their burden of proving that the unit is complying, with the restriction on the percentage of annual gross generation that may be supplied to the electric grid described in paragraph (b)(1) of this section during any year that commences on or after January 1, 2009.

(vi) A unit that loses its exemption in accordance with subparagraph (b)(3)(v) of this section shall be subject to the requirements of this Part. For the purpose of applying permitting requirements under Subpart XX-3, allocating allowances under Subpart XX-5, and applying monitoring requirements under Subpart XX-8, the unit shall be treated as commencing operation on the date the unit loses its exemption.

(4) *Deduction of tons from NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program limited industrial exemption set-aside account*. In the event that the REGULATORY AGENCY grants an exemption under this subdivision to a CO_2 source, with one or more units that on January 1, 2005, serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe, the REGULATORY AGENCY shall retire for each subsequent allocation year the number of CO_2 tons equal to the exempt

source's average annual emissions over the most recent three calendar years for which data are available. The retired tons shall be taken from the set-aside established for such purpose under section XX-5.3.

XX-1.5 Standard requirements.

(a) *Permit requirements*. **[Each state's text for this subdivision will likely be different because the states have unique permitting requirements. The text below illustrates how this subdivision could be drafted and does not necessarily represent what an individual RGGI state will propose.]**

(1) The CO_2 authorized account representative of each CO_2 budget source required to have an operating permit pursuant to **[Insert Reference to state's Permitting Regulation(s)]** of this Title and each CO_2 budget unit required to have an operating permit pursuant to **[Insert Reference to state's Permitting Regulation(s)]** of this Title shall:

(i) Submit to the REGULATORY AGENCY a complete CO_2 budget permit application under section XX-3.3 in accordance with the deadlines specified in section XX-3.2; and

(ii) Submit in a timely manner any supplemental information that the REGULATORY AGENCY determines is necessary in order to review the CO_2 budget permit application and issue or deny a CO_2 budget permit.

(2) The owners and operators of each CO_2 budget source required to have an operating permit pursuant to **[Insert Reference to state's Permitting Regulation(s)]** of this Title and each CO_2 budget unit required to have an operating permit pursuant to **[Insert Reference to state's Permitting Regulation(s)]** of this Title for the source shall have a CO_2 budget permit and operate the CO_2 budget source and the CO_2 budget unit at the source in compliance with such CO_2 budget permit.

(b) *Monitoring requirements*.

(1) The owners and operators and, to the extent applicable, the CO_2 authorized account representative of each CO_2 budget source and each CO_2 budget unit at the source shall comply with the monitoring requirements of Subpart XX-8.

(2) The emissions measurements recorded and reported in accordance with Subpart XX-8 shall be used to determine compliance by the unit with the CO_2 requirements under subdivision (c) of this section.

(c) *CO_2 requirements*.

(1) The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under section XX-6.5, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions for the control period from all CO_2 budget units at the source, less the CO_2 allowances deducted to meet the requirements of paragraph XX-1.5(c)(2), with respect to the previous two interim control periods, as determined in accordance with Subparts XX-6 and XX-8.

(2) The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under section XX-6.5, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions for the interim control period from all CO_2 budget units at the source multiplied by 0.50, as determined in accordance with Subparts XX-6 and XX-8.

(3) Each ton of CO_2 emitted in excess of the CO_2 budget emissions limitation for a control period shall constitute a separate violation of this Part and applicable federal and state law.

(4) Each ton of excess interim emissions shall constitute a separate violation of this Part and applicable state law.

(5) A CO_2 budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later, of January 1, 2009 or the date on which the unit commences operation.

(6) CO_2 allowances shall be held in, deducted from, or transferred among CO_2 Allowance Tracking System accounts in accordance with Subparts XX-5, XX-6, and XX-7, and section XX-10.7.

(7) A CO_2 allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1) or (2) of this section, for a control period or interim control period that ends prior to the year for which the CO_2 allowance was allocated. A CO_2 offset allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1) or (2) of this section, beyond the applicable percent limitations set out in paragraph XX-6.5(a)(3).

(8) A CO_2 allowance under the CO_2 Budget Trading Program is a limited authorization by the REGULATORY AGENCY or a participating state to emit one ton of CO_2 in accordance with the CO_2 Budget Trading Program. No provision of the CO_2 Budget Trading Program, the CO_2 budget permit application, or the CO_2 budget permit or any provision of law shall be construed to limit the authority of the REGULATORY AGENCY or a participating state to terminate or limit such authorization.

(9) A CO_2 allowance under the CO_2 Budget Trading Program does not constitute a property right.

(d) *Excess emissions requirements*. The owners and operators of a CO_2 budget source that has excess emissions in any control period, or excess interim emissions for any interim control period, shall:

(1) Forfeit the CO_2 allowances required for deduction under paragraph XX-

6.5(d)(1), provided CO_2 offset allowances may not be used to cover any part of such excess emissions; and

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed under paragraph XX-6.5(d)(2).

(e) *Recordkeeping and reporting requirements.*

(1) Unless otherwise provided, the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source shall keep on site at the source each of the following documents for a period of 10 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 10 years, in writing by the REGULATORY AGENCY.

(i) The account certificate of representation for the CO_2 authorized account representative for the source and each CO_2 budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with section XX-2.4, provided that the certificate and documents shall be retained on site at the source beyond such 10-year period until such documents are superseded because of the submission of a new account certificate of representation changing the CO_2 authorized account representative.

(ii) All emissions monitoring information, in accordance with Subpart XX-8 and 40 CFR 75.57.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CO_2 Budget Trading Program.

(iv) Copies of all documents used to complete a CO_2 budget permit application and any other submission under the CO_2 Budget Trading Program or to demonstrate compliance with the

requirements of the CO_2 Budget Trading Program.

(2) The CO_2 authorized account representative of a CO_2 budget source and each CO_2 budget unit at the source shall submit the reports and compliance certifications required under the CO_2 Budget Trading Program, including those under Subpart XX-4.

(f) *Liability*.

(1) No permit revision shall excuse any violation of the requirements of the CO_2 Budget Trading Program that occurs prior to the date that the revision takes effect.

(2) Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget source (including a provision applicable to the CO_2 authorized account representative of a CO_2 budget source) shall also apply to the owners and operators of such source and of the CO_2 budget units at the source.

(3) Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget unit (including a provision applicable to the CO_2 authorized account representative of a CO_2 budget unit) shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities*. No provision of the CO_2 Budget Trading Program, a CO_2 budget permit application, or a CO_2 budget permit, shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the CO_2 authorized account representative of the CO_2 budget source or CO_2 budget unit from compliance with any other provisions of applicable State and federal law regulations.

XX-1.6 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day

the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CO_2 Budget Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

XX-1.7 Severability.

If any provision of this Part, or its application to any particular person or circumstances, is held invalid, the remainder of this Part, and the application thereof to other persons or circumstances, shall not be affected thereby.

Subpart XX-2 CO_2 Authorized Account Representative for CO_2 Budget Sources

XX-2.1 Authorization and responsibilities of the CO_2 authorized account representative.

(a) Except as provided under section XX-2.2, each CO_2 budget source, including all CO_2 budget units at the source, shall have one and only one CO_2 authorized account representative, with regard to all matters under the CO_2 Budget Trading Program concerning the source or any CO_2 budget unit at the source.

(b) The CO_2 authorized account representative of the CO_2 budget source shall be selected by an agreement binding on the owners and operators of the source and all CO_2 budget units at the source and must act in accordance with the certificate of representation under section XX-2.4.

(c) Upon receipt by the REGULATORY AGENCY or its agent of a complete account certificate of representation under section XX-2.4, the CO_2 authorized account representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CO_2 budget source represented and each CO_2 budget unit at the source in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CO_2 authorized account representative by the REGULATORY AGENCY or a court regarding the source or unit.

(d) No CO_2 budget permit shall be issued, and no CO_2 Allowance Tracking System account shall be established for a CO_2 budget source, until the REGULATORY AGENCY or its agent has received a complete account certificate of representation under section XX-2.4 for a CO_2 authorized account representative of the source and the CO_2 budget units at the source. Each submission under the CO_2 Budget Trading Program shall be submitted, signed, and certified by the CO_2 authorized account representative for each CO_2 budget source on behalf of which the submission is made.

(e) Each such submission shall include the following certification statement by the CO_2 authorized account representative:
"I am authorized to make this submission on behalf of the owners and Operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(f) The REGULATORY AGENCY or its agent will accept or act on a submission made on behalf of owners or operators of a CO_2 budget source or a CO_2 budget unit only if the submission has been made, signed, and certified in accordance with subdivision (e) of this section.

XX-2.2 CO_2 authorized alternate account representative.

(a) An account certificate of representation may designate one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative.

(b) Upon receipt by the REGULATORY AGENCY or its agent of a complete account certificate of representation under section XX-2.4, any representation, action, inaction, or submission by the CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

(c) Except in this section and subdivision XX-2.1(a), section XX-2.3, section XX-2.4, and section XX-6.2, whenever the term "CO_2 authorized account representative" is used in this Part, the term shall be construed to include the CO_2 authorized alternate account representative.

XX-2.3 Changing the CO_2 authorized account representatives and the CO_2 authorized alternate account representative; changes in the owner and operators.

(a) *Changing the CO_2 authorized account representative*. The CO_2 authorized account representative may be changed at any time upon receipt by the REGULATORY AGENCY or its agent of a superseding complete account certificate of representation

under section XX-2.4. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative or CO_2 authorized alternate account representative prior to the time and date when the REGULATORY AGENCY or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

(b) *Changing the CO_2 authorized alternate account representative*. The CO_2 authorized alternate account representative may be changed at any time upon receipt by the REGULATORY AGENCY or its agent of a superseding complete account certificate of representation under section XX-2.4. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous or CO_2 authorized alternate account representative or CO_2 authorized alternate account representative prior to the time and date when the REGULATORY AGENCY or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized alternate account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

(c) *Changes in the owners and operators*.

(1) In the event a new owner or operator of a CO_2 budget source or a CO_2 budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative of the source or unit, and the decisions, orders, actions, and inactions of the REGULATORY AGENCY, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CO_2 budget source or a CO_2 budget unit, including the addition of a new owner or operator, the CO_2 authorized account representative or CO_2 authorized alternate account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.

XX-2.4 Account certificate of representation.

(a) A complete account certificate of representation for a CO_2 authorized account representative or a CO_2 authorized alternate account representative shall include the following elements in a format prescribed by the REGULATORY AGENCY or its agent:

(1) Identification of the CO_2 budget source and each CO_2 budget unit at the source for which the account certificate of representation is submitted;

(2) The name, address, e-mail address, and telephone number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

(3) A list of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source;

(4) The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: *"I certify that I was selected as the CO_2 authorized account representative or CO_2 authorized alternate account representative, as applicable, by an agreement binding on the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Budget Trading Program on behalf of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source and that each such owner and operator shall be fully bound by my representations,*

actions, inactions, or submissions and by any decision or order issued to me by the REGULATORY AGENCY or a court regarding the source or unit."; and

(5) The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed.

(b) Unless otherwise required by the REGULATORY AGENCY or its agent, documents of agreement referred to in the account certificate of representation shall not be submitted to the REGULATORY AGENCY or its agent. Neither the REGULATORY AGENCY nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

XX-2.5 Objections concerning the CO_2 authorized account representative.

(a) Once a complete account certificate of representation under section XX-2.4 has been submitted and received, the REGULATORY AGENCY and its agent will rely on the account certificate of representation unless and until the REGULATORY AGENCY or its agent receives a superseding complete account certificate of representation under section XX-2.4.

(b) Except as provided in subdivision XX-2.3(a) or (b), no objection or other communication submitted to the REGULATORY AGENCY or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or the finality of any decision or order by the REGULATORY AGENCY or its agent under the CO_2 Budget Trading Program.

(c) Neither the REGULATORY AGENCY nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CO_2 authorized account representative, including private legal

disputes concerning the proceeds of CO_2 allowance transfers.

XX-2.6 Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative.

(a) A CO_2 authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the REGULATORY AGENCY or its agent under this Part.

(b) A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the REGULATORY AGENCY or its agent under this part.

(c) In order to delegate authority to make an electronic submission to the REGULATORY AGENCY or its agent in accordance with subdivision (a) and (b) of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, must submit to the REGULATORY AGENCY or its agent a notice of delegation, in a format prescribed by the REGULATORY AGENCY that includes the following elements:

(1) The name, address, e-mail address, and telephone number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(2) The name, address, e-mail address, and telephone number of each such natural person, herein referred to as the “electronic submission agent”;

(3) For each such natural person, a list of the type of electronic submissions under subdivision (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CO_2 authorized account representative or CO_2 authorized alternate account representative:

(i) *“I agree that any electronic submission to the REGULATORY AGENCY or its agent that is by a natural person identified in this*

notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subdivision XX-2.6(d) shall be deemed to be an electronic submission by me."

(ii) "*Until this notice of delegation is superseded by another notice of delegation under subdivision XX-2.6(d), I agree to maintain an e-mail account and to notify the REGULATORY AGENCY or its agent immediately of any change in my e-mail address unless all delegation authority by me under section XX-2.6 is terminated."*

(d) A notice of delegation submitted under subdivision (c) of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the REGULATORY AGENCY or its agent and until receipt by the REGULATORY AGENCY or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in subparagraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under subdivision (d) of this section shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

(f) A CO_2 authorized account representative may delegate, to one or more natural

persons, his or her authority to review information in the CO_2 allowance tracking system under this part.

(g) A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his or her authority to review information in the CO_2 allowance tracking system under this part.

(h) In order to delegate authority to review information in the CO_2 allowance tracking system in accordance with subdivision (f) and (g) of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, must submit to the REGULATORY AGENCY or its agent a notice of delegation, in a format prescribed by the REGULATORY AGENCY that includes the following elements:

(1) The name, address, e-mail address, and telephone number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(2) The name, address, e-mail address, and telephone number of each such natural person, herein referred to as the "reviewer";

(3) For each such natural person, a list of the type of information under subdivision (f) or (g) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CO_2 authorized account representative or CO_2 authorized alternate account representative:

(i) *"I agree that any information that is reviewed by a natural person identified in this notice of delegation and of a type listed for such information accessible by the reviewer in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subdivision XX-2.6(i) shall be*

deemed to be a reviewer by me."

(ii) "*Until this notice of delegation is superseded by another notice of delegation under subdivision XX-2.6(i), I agree to maintain an e-mail account and to notify the REGULATORY AGENCY or its agent immediately of any change in my e-mail address unless all delegation authority by me under section XX-2.6 is terminated."*

(i) A notice of delegation submitted under subdivision (h) of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the REGULATORY AGENCY or its agent and until receipt by the REGULATORY AGENCY or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified reviewer, add a new reviewer, or eliminate entirely any delegation of authority.

Subpart XX-3 Permits

[Each state's text for this Subpart will likely be different because states have unique permitting requirements. The text below illustrates how this Subpart could be drafted and does not necessarily represent what an individual RGGI state will propose.]

XX-3.1 CO_2 budget permit requirements.

(a) Each CO_2 budget source must have a permit issued by the REGULATORY AGENCY pursuant to **[Insert Reference to State's Permitting Regulation(s)]** of this Title.

(b) Each CO_2 budget permit shall contain all applicable CO_2 Budget Trading Program requirements and shall be a complete and distinguishable portion of the permit

under subdivision (a) of this section.

XX-3.2 Submission of CO_2 budget permit applications.

For any CO_2 budget source, the CO_2 authorized account representative shall submit a complete CO_2 budget permit application under section XX-3.3 covering such CO_2 budget source to the REGULATORY AGENCY by the later of January 1, 2009 or 12 months before the date on which the CO_2 budget source, or a new unit at the source, commences operation.

XX-3.3 Information requirements for CO_2 budget permit applications.

(a) A complete CO_2 budget permit application shall include the following elements concerning the CO_2 budget source for which the application is submitted, in a format prescribed by the REGULATORY AGENCY:

(1) Identification of the CO_2 budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration of the United States Department of Energy, if applicable;

(2) Identification of each CO_2 budget unit at the CO_2 budget source; and

(3) The standard requirements under section XX-1.5.

Subpart XX-4 Compliance Certification

XX-4.1 Compliance certification report.

(a) *Applicability and deadline*. For each control period in which a CO_2 budget source is subject to the CO_2 requirements of XX-1.5(c), the CO_2 authorized account representative of the source shall submit to the REGULATORY AGENCY by the March 1 following the relevant control period, a compliance certification report. A compliance certification report is not required as part of the compliance obligation during an interim

control period.

(b) *Contents of report*. The CO_2 authorized account representative shall include in the compliance certification report under subdivision (a) of this section the following elements, in a format prescribed by the REGULATORY AGENCY:

(1) Identification of the source and each CO_2 budget unit at the source;

(2) At the CO_2 authorized account representative's option, the serial numbers of the CO_2 allowances that are to be deducted from the source's compliance account under section XX-6.5 for the control period, including the serial numbers of any CO_2 offset allowances that are to be deducted subject to the limitations of paragraph XX-6.5(a)(3); and

(3) The compliance certification under subdivision (c) of this section.

(c) *Compliance certification*. In the compliance certification report under subdivision (a) of this section, the CO_2 authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the CO_2 budget units at the source in compliance with the CO_2 Budget Trading Program, whether the source and each CO_2 budget unit at the source for which the compliance certification is submitted was operated during the calendar years covered by the report in compliance with the requirements of the CO_2 Budget Trading Program , including:

(1) Whether the source was operated in compliance with the CO_2 requirements of XX-1.5(c);

(2) Whether the monitoring plan applicable to each unit at the source has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute CO_2 emissions to the unit, in accordance with Subpart XX-8;

(3) Whether all the CO_2 emissions from the units at the source were monitored or accounted for through the missing data procedures and

reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with Subpart XX-8. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

(4) Whether the facts that form the basis for certification under Subpart XX-8 of each monitor at each unit at the source, or for using an excepted monitoring method or alternative monitoring method approved under Subpart XX-8, if any, have changed; and

(5) If a change is required to be reported under paragraph (c)(4) of this section, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

XX-4.2 REGULATORY AGENCY's action on compliance certifications.

(a) The REGULATORY AGENCY or its agent may review and conduct independent audits concerning any compliance certification or any other submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions.

(b) The REGULATORY AGENCY or its agent may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on the information in the compliance certifications or other submissions, as adjusted under subdivision (a) of this section.

Subpart XX-5 CO_2 Allowance Allocations

XX-5.1 NAME OF RELEVANT RGGI STATE CO_2 trading program base budget.

(a) For 2018, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(b) For 2019, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(c) For 2020, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(d) For 2021, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(e) For 2022, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(f) For 2023, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(g) For 2024, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(h) For 2025, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(i) For 2026, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(j) For 2027, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading

Program base budget is___tons.

(k) For 2028, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(l) For 2029, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(m) For 2030 and each succeeding calendar year, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

[…or as established in a future program adjustment.]

XX-5.2 Undistributed and unsold CO_2 allowances

(a) REGULATORY AGENCY may retire undistributed CO_2 allowances at the end of each control period.

(b) REGULATORY AGENCY may retire unsold CO_2 allowances at the end of each control period.

XX-5.3 CO_2 allowance allocations.

(a) *General allocations*. **[Allocation provisions will vary from state to state, provided at least 25% of the allocations will go to a consumer benefit or strategic energy purpose.]**

(b) *Consumer benefit or strategic energy purpose allocation.* The REGULATORY AGENCY will allocate a minimum of twenty-five percent of the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget to the consumer benefit or strategic energy purpose set-aside account.

[The reference to the consumer benefit or strategic energy purpose account

illustrates how this account could be labeled and does not necessarily represent what an individual RGGI state will propose.]

(c) *CO_2 Allowances available for allocation*. For the allocation year 2018 and each succeeding calendar year, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget shall be the maximum number of allowances available for allocation in a given allocation year, except for CO_2 offset allowances and CO_2 CCR allowances. In any year in which there is no adjusted budget, the adjusted budget shall equal the base budget.

(d) *Cost Containment Reserve (CCR) allocation*. The REGULATORY AGENCY shall allocate CO_2 CCR allowances, separate from and additional to the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget set forth in section XX-5.1, to the RELEVANT STATE AUCTION ACCOUNT. The CCR allocation is for the purpose of containing the cost of CO_2 allowances. The REGULATORY AGENCY shall allocate CO_2 CCR allowances in the following manner:

(1) The REGULATORY AGENCY shall initially allocate___CO_2 CCR allowances for calendar year 2014.

(2) On or before January 1, 2015 and each calendar year thereafter through 2020, the REGULATORY AGENCY shall allocate CO_2 CCR allowances in an amount equal to _____, minus the number of CO_2 CCR allowances that remain in the RELEVANT STATE AUCTION ACCOUNT at the end of the prior calendar year.

(3) On or before January 1, 2021 and each year thereafter, the REGULATORY AGENCY shall allocate current vintage year CCR allowances equal to the quantity in Table 3, and withdraw the number of CO_2 CCR allowances that remain in the RELEVANT STATE AUCTION ACCOUNT at the end of the prior calendar year:

Table 3. CCR allowances from 2021 forward

2021	2022	2023	2024	2024	2025	2026	2027	2028	2029	2030 and each year thereafter
TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

(e) *Emissions Containment Reserve (ECR) Withholding*. The REGULATORY AGENCY shall convert and transfer any CO_2 allowances that have been withheld from any auction(s) into the RELEVANT STATE ECR ACCOUNT. The ECR withholding is for the purpose of additional emissions reductions in the event of lower than anticipated emissions reduction costs. The REGULATORY AGENCY shall withhold CO_2 ECR allowances in the following manner.

(1) If the condition in paragraph 9.2 (d)(1) is met at an auction, then the maximum number of CO_2 ECR allowances that will be withheld from that auction will be equal to the quantity shown in Table 4 minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction(s) in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the RELEVANT STATE ECR ACCOUNT.

Table 4. ECR allowances from 2021 forward

2021	2022	2023	2024	2024	2025	2026	2027	2028	2029	2030 and each year thereafter
TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

(2) Allowances that have been transferred into the RELEVANT STATE ECR ACCOUNT shall not be withdrawn.

(f) *First control period adjustment for banked allowances.* By January 15, 2014, the REGULATORY AGENCY shall establish the first control period adjustment for banked allowances quantity for allocation years 2014 through 2020:

Table 5. First control period adjustment for banked allowances

2014	2015	2016	2017	2018	2019	2020
Insert amount						

(g) *Second control period adjustment for banked allowances.* On March 17, 2014, the REGULATORY AGENCY shall establish the second control period adjustment for banked allowances quantity the allocation years 2015 through 2020:

Table 6. Second control period adjustment for banked allowances

2015	2016	2017	2018	2019	2020
Insert amount					

(h) *Third adjustment for banked allowances.* On March 15, 2021, the REGULATORY AGENCY shall determine the third adjustment for banked allowances quantity for allocation years 2021 through 2025 through the application of the following formula:

$$TABA = \frac{TA - TAE}{5} \times RS\%$$

Where:

TABA is the third adjustment for banked allowances quantity in tons.

TA, third adjustment, is the total quantity of allowances of vintage years prior to 2021 held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states, as reflected in the CO_2 Allowance

Tracking System on March 15, 2021.

TAE, third adjustment emissions, is the total quantity of 2018, 2019 and 2020 emissions from all CO_2 budget sources in all participating states, reported pursuant to CO_2 Budget Trading Program as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

RS% is RELEVANT RGGI STATE'S 2021 budget divided by the 2021 regional budget.

(i) *CO_2 Budget Trading Program adjusted budgets for 2018 through 2020.* On April 15, 2014 the REGULATORY AGENCY shall establish the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budgets for the 2018 through 2020 allocation years in the following table:

Table 7. CO_2 Budget Trading Program adjusted budgets

2018	2019	2020
Insert amount		

(j) *CO_2 Budget Trading Program adjusted budgets for 2021 through 2025.* On or before April 15, 2021, the REGULATORY AGENCY shall establish the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budgets for the 2021 through 2025 allocation years by the following formula:

AB = BB – TABA

Where:

AB is the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget.

BB is the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program

base budget.

TABA is the third adjustment for banked allowances quantity in tons.

(k) After making the determinations in XX-5.3 (j), the REGULATORY AGENCY or its Agent will publish the CO_2 trading program adjusted budgets for the 2021 through 2025 allocation years.

[The following subdivision is an optional voluntary renewable energy market set-aside provision. It represents one way a state could implement such a set-aside.]

(l) *Voluntary renewable energy market set-aside allocation*. For each control period, the REGULATORY AGENCY shall allocate to the voluntary renewable energy market set-aside account a certain number of tons, calculated as set forth in this subdivision, from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget set forth in section XX-5.1, as applicable. The REGULATORY AGENCY shall administer the voluntary renewable energy set-aside in accordance with this subdivision.

(1) The REGULATORY AGENCY will open and manage a general account for the voluntary renewable energy market set-aside for each control period.

(2) The number of tons that will be allocated to the voluntary renewable energy market set-aside account in a specific control period will be determined as set out in this paragraph.

(i) Any person may submit data to the REGULATORY AGENCY documenting purchases of voluntary renewable energy that meet the requirements of this subdivision by no later than the July 30 prior to the beginning of a control period. Such data must be from reputable sources, which may include retail electricity providers, organizations that certify renewable energy products, and other parties as determined by the REGULATORY AGENCY. To be considered, data must be verifiable and document the following for voluntary renewable energy purchases.

(a) Documentation of voluntary renewable energy or renewable energy attribute credit purchases by retail customers, by customer class, in the State during the most recent three-year period for which data are available.

(b) Documentation that the renewable energy or renewable energy attributes related to voluntary renewable energy or renewable energy attribute credit sales was procured by the retail provider.

(c) Time period when the retail purchase(s) was made.

(d) State where the electricity was generated or the renewable energy attribute credit was created, including documentation of facility name, unique generator identification number, and fuel type.

(e) Time period when the electricity was generated or the renewable energy attribute credit was created.

(ii) Subject to the timely receipt of adequate data pursuant to subparagraph (i) of this paragraph, and based on such data, the REGULATORY AGENCY shall project the voluntary renewable energy purchases in the State during a control period that represents renewable energy generation in one or more participating states. The megawatt-hours (MWh) of projected voluntary renewable energy purchases in a control period shall be multiplied by the marginal CO_2 emissions rate (lbs. CO_2/MWh) in the control area where the generation occurred, as determined by the REGULATORY AGENCY. If data to determine the marginal emissions rate is unavailable, the average emissions rate shall be used, as determined by the REGULATORY AGENCY.

(iii) The CO_2 tons to be allocated to the voluntary renewable energy set-aside account shall be calculated as follows:

CO_2 tons = MP x EF

Where:

CO_2 tons, rounded down to the nearest whole ton, is the number of allowances to be placed in the reserve account;

MP is the projected MWh of voluntary renewable energy purchases in the State during the future control period that meets the requirements of this subdivision; and

EF is the CO_2 emissions factor for the control area where the electricity represented by the sale was generated.

(iv) If following the end of a control period, the number of CO_2 allowances allocated to the voluntary renewable energy set-aside account is less than the number of CO_2 tons represented by the actual MWh of voluntary renewable energy purchases during the control period, the REGULATORY AGENCY will add the difference between CO_2 tons represented by actual purchases, as calculated in accordance with subparagraph (iii) of this paragraph, and CO_2 allowances held in the set-aside account to the projection for the following control period, pursuant to paragraph (2) of this subdivision. If following the end of a control period, the number of CO_2 allowances allocated to the voluntary renewable energy set-aside account is greater than the number of CO_2 tons represented by the actual MWh of voluntary renewable energy purchases during the control period, the REGULATORY AGENCY will subtract the difference between CO_2 tons represented by actual purchases, as calculated in accordance with subparagraph (iii) of this paragraph, and CO_2 allowances held in the set-aside account from the

projection for the following control period, pursuant to paragraph (2) of this subdivision. In no event shall the size of the voluntary renewable set-aside exceed_____tons.

(3) As of the December 31 that is after the end of a control period for which an allocation has been made to the voluntary renewable energy set-aside account, the REGULATORY AGENCY shall determine the actual MWh of voluntary renewable energy purchases that occurred during the control period. The REGULATORY AGENCY shall retire CO_2 allowances in the voluntary renewable energy set-aside account in an amount up to the number of tons of CO_2 represented by actual voluntary renewable energy purchases, based on actual MWh purchases and the emissions factor determined pursuant to paragraph (2) of this subdivision.

[The following subdivision is an optional limited industrial exemptions set-aside allocation provision. It represents one way a state could implement such a set-aside.]

(m) *Limited industrial exemption set-aside allocation.* The limited industrial exemption set-aside allocation will consist of_tons from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget set forth in section XX-5.1, as applicable. For each control period, the AGENCY will determine CO_2 allowance allocations in accordance with the following procedures.

(1) The REGULATORY AGENCY will open and manage a general account for the limited exemption set-aside for each control period.

(2) As of the January 1 that is after the date that an exemption under subdivision XX-1.4(b) has been granted, for each allocation year the REGULATORY AGENCY will retire CO_2 allowances in the limited industrial exemption set-aside general account as determined pursuant to paragraph XX-1.4(b)(4).

(3) After retirement of allowances pursuant to paragraph (2) of this subdivision,

the REGULATORY AGENCY will determine whether any CO_2 allowances remain in the limited industrial exemption set-aside general account for the control period. The REGULATORY AGENCY will transfer any such remaining CO_2 allowances from the limited industrial exemption set-aside allocation general account to the compliance account of each CO_2 budget source that was allocated allowances pursuant to subdivision (a) of this section using the following methodology:

Existing CO_2 budget unit's share of the CO_2 allowances remaining in the limited industrial exemption set-aside general account = Total CO_2 allowances remaining in the limited industrial exemption set-aside general account x (The individual CO_2 budget unit's CO_2 allowance allocation determined in accordance with subdivision (a) of this section ÷ The NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program annual base budget, as applicable)

Where:

"Total CO_2 allowances remaining in the limited industrial exemption set-aside allocation general account" is the total number of CO_2 allowances remaining in the limited industrial exemption set-aside allocation general account (established under paragraph (e)(1) of this section) for the particular control period to which the limited industrial exemption set-aside allocation applies; and

"The individual CO_2 budget unit's CO_2 allowance allocation" is the number of CO_2 allowances allocated under subdivision (a) of this section to the individual CO_2 budget unit for the control period to which the limited industrial exemption set- aside allocation applies.

The REGULATORY AGENCY will only transfer CO_2 allowances in whole

ton increments. The REGULATORY AGENCY will continue to hold any fractional shares of CO_2 allowances in the name of the CO_2 budget unit as banked CO_2 allowances until they may be combined with other fractional shares of CO_2 allowances in future years and then transferred as whole ton increments.

Subpart XX-6 CO_2 Allowance Tracking System

XX-6.1 CO_2 Allowance Tracking System accounts.

(a) *Nature and function of compliance accounts*. Consistent with subdivision XX-6.2(a), the REGULATORY AGENCY or its agent will establish one compliance account for each CO_2 budget source. Allocations of CO_2 allowances pursuant to Subpart XX-5 and deductions or transfers of CO_2 allowances pursuant to sections XX-4.2, XX-6.5, XX-6.7, or Subpart XX-7 will be recorded in the compliance accounts in accordance with this Subpart.

(b) *Nature and function of general accounts*. Consistent with subdivision XX- 6.2(b), the REGULATORY AGENCY or its agent will establish, upon request, a general account for any person. Transfers of CO_2 allowances pursuant to Subpart XX-7 will be recorded in the general account in accordance with this Subpart.

XX-6.2 Establishment of accounts.

(a) *Compliance accounts*. Upon receipt of a complete account certificate of representation under section XX-2.4, the REGULATORY AGENCY or its agent will establish a compliance account for each CO_2 budget source for which the account certificate of representation was submitted.

(b) *General accounts*.

(1) *Application for general account.* Any person may apply to open a general

account for the purpose of holding and transferring CO_2 allowances. An application for a general account may designate one and only one CO_2 authorized account representative and one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative. A complete application for a general account shall be submitted to the REGULATORY AGENCY or its agent and shall include the following elements in a format prescribed by the REGULATORY AGENCY or its agent:

(i) Name, address, e-mail address, and telephone number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

(ii) At the option of the CO_2 authorized account representative, organization name and type of organization;

(iii) A list of all persons subject to a binding agreement for the CO_2 authorized account representative or any CO_2 authorized alternate account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

(iv) The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: “I certify that I was selected as the CO_2 authorized account representative or the CO_2 authorized alternate account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under

the CO_2 Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the REGULATORY AGENCY or its agent or a court regarding the general account.";

(v) The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed; and

(vi) Unless otherwise required by the REGULATORY AGENCY or its agent, documents of agreement referred to in the application for a general account shall not be submitted to the REGULATORY AGENCY or its agent. Neither the REGULATORY AGENCY nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of CO_2 authorized account representative*.

(i) Upon receipt by the REGULATORY AGENCY or its agent of a complete application for a general account under paragraph (b)(1) of this section:

(a) The REGULATORY AGENCY or its agent will establish a general account for the person or persons for whom the application is submitted.

(b) The CO_2 authorized account representative and any CO_2 authorized alternate account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized

account representative or any CO_2 authorized alternate account representative and such person. Any such person shall be bound by any order or decision issued to the CO_2 authorized account representative or any CO_2 authorized alternate account representative by the REGULATORY AGENCY or its agent or a court regarding the general account.

(c) Any representation, action, inaction, or submission by any CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CO_2 authorized account representative or any CO_2 authorized alternate account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission shall include the following certification statement by the CO_2 authorized account representative or any CO_2 authorized alternate account representative:

"I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting

required statements and information, including the possibility of fine or imprisonment."

(iii) The REGULATORY AGENCY or its agent will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with subparagraph (b)(2)(ii) of this section.

(3) *Changing CO_2 authorized account representative and CO_2 authorized alternate account representative; changes in persons with ownership interest*.

(i) The CO_2 authorized account representative for a general account may be changed at any time upon receipt by the REGULATORY AGENCY or its agent of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the REGULATORY AGENCY or its agent receives the superseding application for a general account shall be binding on the new CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(ii) The CO_2 authorized alternate account representative for a general account may be changed at any time upon receipt by the REGULATORY AGENCY or its agent of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the

REGULATORY AGENCY or its agent receives the superseding application for a general account shall be binding on the new CO_2 authorized alternate account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(iii) In the event a new person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative, and the decisions, orders, actions, and inactions of the REGULATORY AGENCY or its agent, as if the new person were included in such list.

(iv) Within 30 days following any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or deletion of persons, the CO_2 authorized account representative or any CO_2 authorized alternate account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CO_2 allowances in the general account to include the change.

(4) *Objections concerning CO_2 authorized account representative*.

(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the REGULATORY AGENCY or its agent will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the

REGULATORY AGENCY or its agent.

(ii) Except as provided in subparagraphs (b)(3)(i) and (ii) of this section, no objection or other communication submitted to the REGULATORY AGENCY or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative or the finality of any decision or order by the REGULATORY AGENCY or its agent under the CO_2 Budget Trading Program.

(iii) Neither the REGULATORY AGENCY nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

(5) *Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative.*

(i) A CO_2 authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the REGULATORY AGENCY or its agent provided for under Subparts XX-6 and XX-7.

(ii) A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the REGULATORY AGENCY or its agent provided for under Subparts XX-6 and XX-7.

(iii) In order to delegate authority to make an electronic submission to

the REGULATORY AGENCY or its agent in accordance with subparagraphs (i) and (ii) of this paragraph, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, must submit to the REGULATORY AGENCY or its agent a notice of delegation, in a format prescribed by the REGULATORY AGENCY that includes the following elements:

(a) The name, address, e-mail address, and telephone number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(b) The name, address, e-mail address, and telephone number of each such natural person, herein referred to as "electronic submission agent";

(c) For each such natural person, a list of the type of electronic submissions under subdivision (a) or (b) of this section for which authority is delegated to him or her; and

(d) The following certification statements by such CO_2 authorized account representative or CO_2 authorized alternate account representative:

(1) "I agree that any electronic submission to the REGULATORY AGENCY or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subparagraph XX- 6.2(b)(5)(iv) shall be deemed to be

an electronic submission by me."

(2) "Until this notice of delegation is superseded by another notice of delegation under subparagraph XX-6.2(b)(5)(iv), I agree to maintain an e-mail account and to notify the REGULATORY AGENCY or its agent immediately of any change in my e-mail address unless all delegation authority by me under paragraph XX-6.2(b)(5) is terminated."

(iv) A notice of delegation submitted under subparagraph (iii) of this paragraph shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the REGULATORY AGENCY or its agent and until receipt by the REGULATORY AGENCY or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in sub-clause (iii)*(d)(1)* of this paragraph and made in accordance with a notice of delegation effective under subparagraph (iv) of this paragraph shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

(c) *Account identification*. The REGULATORY AGENCY or its agent will assign a unique identifying number to each account established under subdivisions (a) or (b) of this section.

XX-6.3 CO_2 Allowance Tracking System responsibilities of CO_2 authorized account representative.

Following the establishment of a CO_2 Allowance Tracking System account, all submissions to the REGULATORY AGENCY or its agent pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CO_2 allowances in the account, shall be made only by the CO_2 authorized account representative for the account.

XX-6.4 Recordation of CO_2 allowance allocations.

(a) By January 1 of each calendar year, the REGULATORY AGENCY or its agent will record in the following accounts:

(1) In each CO_2 budget source's compliance account, the CO_2 allowances allocated for CO_2 budget units at the source (if any) under subdivision XX-5.3(a); and

(2) The CO_2 allowances allocated for the consumer benefit or strategic energy purpose account under subdivision XX-5.3(b).

[Should states wish to establish other set-aside allocations (for new sources, for example), they would be referred to (at least generically) in the above subdivision.]

(b) Each year the REGULATORY AGENCY or its agent will record CO_2 allowances, as allocated to the unit under Subpart XX-5, in the compliance account for the year after the last year for which CO_2 allowances were previously allocated to the compliance account. Each year, the REGULATORY AGENCY or its agent will also record CO_2 allowances, as allocated under Subpart XX-5, in an allocation set-aside for the year after the last year for which CO_2 allowances were previously allocated to an allocation set-aside.

(c) *Serial numbers for allocated CO_2 allowances*. When allocating CO_2 allowances

to and recording them in an account, the REGULATORY AGENCY or its agent will assign each CO_2 allowance a unique identification number that will include digits identifying the year for which the CO_2 allowance is allocated.

XX-6.5 Compliance.

(a) *Allowances available for compliance deduction.* CO_2 allowances that meet the following criteria are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of XX-1.5(c) for a control period or an interim control period.

(1) The CO_2 allowances, other than CO_2 offset allowances, are of allocation years that fall within a prior control period, the same control period, or the same interim control period for which the allowances will be deducted.

(2) The CO_2 allowances are held in the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that control period or interim control period or are transferred into the compliance account by a CO_2 allowance transfer correctly submitted for recordation under section XX-7.1 by the CO_2 allowance transfer deadline for that control period or interim control period.

(3) For CO_2 offset allowances, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of XX-1.5(c) for a control period or an interim control period may not exceed 3.3 percent of the CO_2 budget source's CO_2 emissions for that control period, or 3.3 percent of 0.50 times the CO_2 budget source's CO_2 emissions for an interim control period, as determined in accordance with Subparts XX-6 and XX-8.

(4) The CO_2 allowances are not necessary for deductions for excess emissions for a prior control period under subdivision (d) of this section.

(b) *Deductions for compliance*. Following the recordation, in accordance with section

XX-7.2, of CO_2 allowance transfers submitted for recordation in the CO_2 budget source's compliance account by the CO_2 allowance transfer deadline for a control period or interim control period, the REGULATORY AGENCY or its agent will deduct CO_2 allowances available under subdivision (a) of this section to cover the source's CO_2 emissions (as determined in accordance with Subpart XX-8) for the control period or interim control period, as follows:

(1) Until the amount of CO_2 allowances deducted equals the number of tons of total CO_2 emissions (or 0.50 times the number of tons of total CO_2 emissions for an interim control period), less any CO_2 emissions attributable to the burning of eligible biomass, determined in accordance with Subpart XX-8, from all CO_2 budget units at the CO_2 budget source for the control period or interim control period; or

(2) If there are insufficient CO_2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more CO_2 allowances available under subdivision (a) of this section remain in the compliance account.

(c) *Identification of available CO_2 allowances by serial number; default compliance deductions.*

(1) The CO_2 authorized account representative for a source's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period or interim control period in accordance with subdivision (b), or (d) of this section. Such identification shall be made in the compliance certification report submitted in accordance with section XX-4.1.

(2) The REGULATORY AGENCY or its agent will deduct CO_2 allowances for a control period or interim control period from the CO_2 budget source's compliance account, in the absence of an identification or in the case of a partial identification of available CO_2 allowances by serial number under

paragraph (c)(1) of this section, in the following order:

(i) First, subject to the relevant compliance deduction limitations under XX-6.5(a)(3) and (d)(1), CO_2 offset allowances. CO_2 offset allowances shall be deducted in chronological order (i.e., CO_2 offset allowances from earlier allocation years shall be deducted before CO_2 offset allowances from later allocation years). In the event that some, but not all, CO_2 offset allowances from a particular allocation year are to be deducted, CO_2 offset allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances.

(ii) Second, any CO_2 allowances, other than CO_2 offset allowances, that are available for deduction under subdivision (a) of this section. CO_2 allowances shall be deducted in chronological order (i.e., CO_2 allowances from earlier allocation years shall be deducted before CO_2 allowances from later allocation years). In the event that some, but not all, CO_2 allowances from a particular allocation year are to be deducted, CO_2 allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances.

(d) *Deductions for excess emissions.*

(1) After making the deductions for compliance under subdivision (b) of this section, the REGULATORY AGENCY or its agent will deduct from the CO_2 budget source's compliance account a number of CO_2 allowances, equal to three times the number of the source's excess emissions. In the event that a source has insufficient CO_2 allowances to cover three times the number of the source's excess emissions, the source shall be required to immediately transfer sufficient allowances into its compliance account. No CO_2 offset allowances may be deducted to account for the source's

excess emissions.

(2) Any CO_2 allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CO_2 budget source or the CO_2 units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under applicable State law. The following guidelines will be followed in assessing fines, penalties or other obligations.

(i) For purposes of determining the number of days of violation, if a CO_2 budget source has excess emissions for a control period, each day in the control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

(ii) Each ton of excess emissions is a separate violation.

(iii) For purposes of determining the number of days of violation, if a CO_2 budget source has excess interim emissions for an interim control period, each day in the interim control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

(iv) Each ton of excess interim emissions is a separate violation.

(3) The propriety of the REGULATORY AGENCY's determination that a CO_2 budget source had excess emissions and the concomitant deduction of CO_2 allowances from that CO_2 budget source's account may be later challenged in the context of the initial administrative enforcement, or any civil or criminal judicial action arising from or encompassing that excess emissions violation. The commencement or pendency of any administrative enforcement, or civil or criminal judicial action arising from or encompassing that excess emissions violation will not act to prevent the REGULATORY AGENCY or its agent from initially deducting the CO_2

allowances resulting from the REGULATORY AGENCY's original determination that the relevant CO_2 budget source has had excess emissions. Should the REGULATORY AGENCY's determination of the existence or extent of the CO_2 budget source's excess emissions be revised either by a settlement or final conclusion of any administrative or judicial action, the REGULATORY AGENCY will act as follows.

(i) In any instance where the REGULATORY AGENCY's determination of the extent of excess emissions was too low, the REGULATORY AGENCY will take further action under paragraphs (d)(1) and (2) of this section to address the expanded violation.

(ii) In any instance where the REGULATORY AGENCY's determination of the extent of excess emissions was too high, the REGULATORY AGENCY will distribute to the relevant CO_2 budget source a number of CO_2 allowances equaling the number of CO_2 allowances deducted which are attributable to the difference between the original and final quantity of excess emissions. Should such CO_2 budget source's compliance account no longer exist, the CO_2 allowances will be provided to a general account selected by the owner or operator of the CO_2 budget source from which they were originally deducted.

(e) The REGULATORY AGENCY or its agent will record in the appropriate compliance account all deductions from such an account pursuant to subdivisions (b) and (d) of this section.

(f) *Action by the REGULATORY AGENCY on submissions*.

(1) The REGULATORY AGENCY may review and conduct independent audits concerning any submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the submissions.

(2) The REGULATORY AGENCY may deduct CO_2 allowances from or

transfer CO_2 allowances to a source's compliance account based on information in the submissions, as adjusted under paragraph (f)(1) of this section.

XX-6.6 Banking.

Each CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under section XX-4.2, section XX-6.5, section XX-6.7, or Subpart XX-7.

XX-6.7 Account error.

The REGULATORY AGENCY or its agent may, at its sole discretion and on his or her own motion, correct any error in any CO_2 Allowance Tracking System account. Within 10 business days of making such correction, the REGULATORY AGENCY or its agent will notify the CO_2 authorized account representative for the account.

XX-6.8 Closing of general accounts.

(a) A CO_2 authorized account representative of a general account may instruct the REGULATORY AGENCY or its agent to close the account by submitting a statement requesting deletion of the account from the CO_2 Allowance Tracking System and by correctly submitting for recordation under section XX-7.1 a CO_2 allowance transfer of all CO_2 allowances in the account to one or more other CO_2 Allowance Tracking System account.

(b) If a general account shows no activity for a period of one year or more and does not contain any CO_2 allowances, the REGULATORY AGENCY or its agent may notify the CO_2 authorized account representative for the account that the account will be closed in the CO_2 Allowance Tracking System 30 business days after the notice is sent. The account will be closed after the 30-day period unless before the end of the 30-day period the REGULATORY AGENCY or its agent receives a correctly submitted transfer

of CO_2 allowances into the account under section XX-7.1 or a statement submitted by the CO_2 authorized account representative demonstrating to the satisfaction of the REGULATORY AGENCY or its agent good cause as to why the account should not be closed. The REGULATORY AGENCY or its agent will have sole discretion to determine if the owner or operator of the unit demonstrated that the account should not be closed.

Subpart XX-7 CO_2 Allowance Transfers

XX-7.1 Submission of CO_2 allowance transfers.

The CO_2 authorized account representatives seeking recordation of a CO_2 allowance transfer shall submit the transfer to the REGULATORY AGENCY or its agent. To be considered correctly submitted, the CO_2 allowance transfer shall include the following elements in a format specified by the REGULATORY AGENCY or its agent:

(a) The numbers identifying both the transferor and transferee accounts;

(b) A specification by serial number of each CO_2 allowance to be transferred;

(c) The printed name and signature of the CO_2 authorized account representative of the transferor account and the date signed;

(d) The date of the completion of the last sale or purchase transaction for the allowance, if any; and

(e) The purchase or sale price of the allowance that is the subject of a sale or purchase transaction under subdivision (d) of this section.

XX-7.2 Recordation.

(a) Within 5 business days of receiving a CO_2 allowance transfer, except as provided in subdivision (b) of this section, the REGULATORY AGENCY or its agent will record a

CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under section XX-7.1; and

(1) The transferor account includes each CO_2 allowance identified by serial number in the transfer.

(2) A CO_2 allowance transfer into or out of a compliance account that is submitted for recordation following the CO_2 allowance transfer deadline and that includes any CO_2 allowances that are of allocation years that fall within a control period or interim control period prior to or the same as the control period or interim control period to which the CO_2 allowance transfer deadline applies will not be recorded until after completion of the process pursuant to XX-6.5(b).

(b) Where a CO_2 allowance transfer submitted for recordation fails to meet the requirements of subdivision (a) of this section, the REGULATORY AGENCY or its agent will not record such transfer.

XX-7.3 Notification.

(a) *Notification of recordation*. Within 5 business days of recordation of a CO_2 allowance transfer under section XX-7.2, the REGULATORY AGENCY or its agent will notify each party to the transfer. Notice will be given to the CO_2 authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation*. Within 10 business days of receipt of a CO_2 allowance transfer that fails to meet the requirements of subdivision XX-7.2(a), the REGULATORY AGENCY or its agent will notify the CO_2 authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CO_2 allowance transfer for recordation following notification of non-recordation.

Subpart XX-8 Monitoring, Reporting & Recordkeeping

XX-8.1 General requirements.

The owners and operators, and to the extent applicable, the CO_2 authorized account representative of a CO_2 budget unit, shall comply with the monitoring, recordkeeping and reporting requirements as provided in this Subpart and all applicable sections of 40 CFR part 75. Where referenced in XX-8, the monitoring requirements of 40 CFR Part 75 shall be adhered to in a manner consistent with the purpose of monitoring and reporting CO_2 mass emissions pursuant to **[these regulations]**. For purposes of complying with such requirements, the definitions in section XX-1.2 and in 40 CFR 72.2 shall apply, and the terms ‘‘affected unit,’’ ‘‘designated representative,’’ and ‘‘continuous emissions monitoring system’’ (or ‘‘CEMS’’) in 40 CFR part 75 shall be replaced by the terms ‘‘CO_2 budget unit,’’ ‘‘CO_2 authorized account representative,’’ and ‘‘continuous emissions monitoring system’’ (or ‘‘CEMS’’), respectively, as defined in section XX-1.2.

For units not subject to an Acid Rain emissions limitation, the term “Administrator” in 40 CFR Part 75 shall be replaced with “the Administrator, REGULATORY AGENCY or its agent.” Owners or operators of a CO_2 budget unit who monitor a non-CO_2 budget unit pursuant to the common, multiple, or bypass stack procedures in 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16 (b)(2)(ii)(B) as pursuant to 40 CFR 75.13, for purposes of complying with **[these regulations]**, shall monitor and report CO_2 mass emissions from such non-CO_2 budget units according to the procedures for CO_2 budget units established in XX-8.1 through XX-8.7.

(a) *Requirements for installation, certification, and data accounting*. The owner or

operator of each CO_2 budget unit must meet the following requirements.

(1) Install all monitoring systems necessary to monitor CO_2 mass emissions in accordance with 40 CFR Part 75, except for equation G-1. Equation G-1 in Appendix G shall not be used to determine CO_2 emissions under this Part. This may require systems to monitor CO_2 concentration, stack gas flow rate, O_2 concentration, heat input, and fuel flow rate.

(2) Successfully complete all certification tests required under section XX-8.2 and meet all other requirements of this Subpart and 40 CFR part 75 applicable to the monitoring systems under paragraph (a)(1) of this section.

(3) Record, report and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance dates*. The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) through (a)(3) of this section on or before the following dates. The owner or operator shall record, report and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) The owner or operator of a CO_2 budget unit, except for a CO_2 budget unit under paragraph (b)(2) of this section, that commences commercial operation before July 1, 2008, must comply with the requirements of this Subpart by January 1, 2009.

(2) The owner or operator of a CO_2 budget unit that commences commercial operation on or after July 1, 2008 must comply with the requirements of this Subpart by the later of the following dates:

(i) January 1, 2009; or

(ii) The earlier of:

(a) 90 unit operating days after the date on which the unit commences commercial operation; or

(b) 180 calendar days after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CO_2 budget unit for which construction of a new stack or flue installation is completed after the applicable deadline under paragraph (b)(1) or (b)(2) of this section by the earlier of:

(i) 90 unit operating days after the date on which emissions first exit to the atmosphere through the new stack or flue; or

(ii) 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue.

(c) *Reporting data.*

(1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in paragraphs (b)(1), (b)(2) and (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or as appropriate minimum potential) values for CO_2 concentration, CO_2 emissions rate, stack gas moisture content, fuel flow rate, heat input, and any other parameter required to determine CO_2 mass emissions in accordance with 40 CFR 75.31(b)(2) or (c)(3), or section 2.4 of appendix D of 40 CFR part 75 as applicable.

(2) The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in paragraph (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in Subpart D, or appendix D of 40 CFR part 75, in lieu of the maximum potential (or as appropriate minimum potential) values for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(3) of this section.

(i) CO_2 budget units subject to an acid rain emissions limitation or

[state-specific annual or CSAPR NOx Ozone Season Trading Program] that qualify for the optional SO_2, NO_X, and CO_2 (for acid rain) or NOx (for **[state-specific annual or CSAPR NOx Ozone Season Trading Program]**) emissions calculations for low mass emissions (LME) units under 40 CFR 75.19 and report emissions for such programs using the calculations under 40 CFR 75.19 , shall also use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

(ii) CO_2 budget units subject to an acid rain emissions limitation or **[state-specific annual or ozone season CAIR citation]** that do not qualify for the optional SO_2, NO_X, and CO_2 (for acid rain) or NOx (for **[state-specific annual or CSAPR NOx Ozone Season Trading Program]**) emissions calculations for LME units under 40 CFR 75.19, shall not use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

(iii) CO_2 budget units not subject to an acid rain emissions limitation or **[state-specific annual or CSAPR NOx Ozone Season Trading Program]** shall qualify for the optional CO_2 emissions calculation for LME units under 40 CFR 75.19, provided that they emit less than 100 tons of NO_X annually and no more than 25 tons of SO_2 annually.

(d) *Prohibitions.*

(1) No owner or operator of a CO_2 budget unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emissions monitoring system without having obtained prior written approval in accordance with section XX-8.6.

(2) No owner or operator of a CO_2 budget unit shall operate the unit so as to discharge, or allow to be discharged, CO_2 emissions to the atmosphere

without accounting for all such emissions in accordance with the applicable provisions of this Subpart and 40 CFR part 75.

(3) No owner or operator of a CO_2 budget unit shall disrupt the continuous emissions monitoring system, any portion thereof, or any other approved emissions monitoring method, and thereby avoid monitoring and recording CO_2 mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this Subpart and 40 CFR part 75.

No owner or operator of a CO_2 budget unit shall retire or permanently discontinue use of the continuous emissions monitoring system, any component thereof, or any other approved emissions monitoring system under this Subpart, except under any one of the following circumstances:

(i) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this Subpart and 40 CFR part 75, by the Administrator, REGULATORY AGENCY for use at that unit that provides emissions data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(ii) The CO_2 authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with subparagraph XX-8.2(d)(3)(i).

XX-8.2 Initial certification and recertification procedures.

(a) The owner or operator of a CO_2 budget unit shall be exempt from the initial certification requirements of this section for a monitoring system under paragraph XX-8.1(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with 40 CFR part 75; and

(2) The applicable quality-assurance and quality-control requirements of 40 CFR 75.21 and appendix B and appendix D of 40 CFR part 75 are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under paragraph XX-8.1(a)(1) exempt from initial certification requirements under subdivision (a) of this section.

(c) Not withstanding XX-8.2(a), if the Administrator has previously approved a petition under 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16(b)(2)(ii)(B) as pursuant to 40 CFR 75.13 for apportioning the CO_2 emissions rate measured in a common stack or a petition under 40 CFR 75.66 of this chapter for an alternative requirement in 40 CFR part 75, the CO_2 authorized account representative shall submit the petition to the Administrator, REGULATORY AGENCY under subdivision XX-8.6(a) to determine whether the approval applies under this program.

(d) Except as provided in subdivision (a) of this section, the owner or operator of a CO_2 budget unit shall comply with the following initial certification and recertification procedures for a continuous emissions monitoring system and an excepted monitoring system under appendix D of 40 CFR part 75 and under paragraph XX-8.1(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology in 40 CFR 75.19 or that qualifies to use an alternative monitoring system under Subpart E of 40 CFR part 75 shall comply with the procedures in subdivision (e) or (f) of this section, respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous emissions monitoring system required under paragraph XX-8.1(a)(1) (which includes the automated data acquisition

and handling system) successfully completes all of the initial certification testing required under 40 CFR 75.20 by the applicable deadlines specified in subdivision XX-8.1(b). In addition, whenever the owner or operator installs a monitoring system in order to meet the requirements of this Subpart in a location where no such monitoring system was previously installed, initial certification in accordance with 40 CFR 75.20 is required.

(2) *Requirements for recertification.*

(i) Whenever the owner or operator makes a replacement, modification, or change in a certified continuous emissions monitoring system under paragraph XX-8.1(a)(1) that the Administrator or the Administrator, REGULATORY AGENCY determines significantly affects the ability of the system to accurately measure or record CO_2 mass emissions or to meet the quality-assurance and quality-control requirements of 40 CFR 75.21 or appendix B to 40 CFR part 75, the owner or operator shall recertify the monitoring system according to 40 CFR 75.20(b).

(ii) For systems using stack measurements such as stack flow, stack moisture content, CO_2 or O_2 monitors, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the Administrator or the Administrator, REGULATORY AGENCY determines to significantly change the flow or concentration profile, the owner or operator shall recertify the continuous emissions monitoring system according to 40 CFR 75.20(b). Examples of changes which require recertification include: replacement of the analyzer, change in location or orientation of the sampling probe or site, or changing of flow rate monitor polynomial coefficients.

(3) *Approval process for initial certifications and recertification*. Subparagraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a monitoring system under paragraph XX-8.1(a)(1). For re-certifications, replace the words "certification" and "initial certification" with the word "recertification," replace the word "certified" with "recertified," and proceed in the manner prescribed in 40 CFR 75.20(b)(5) and (g)(7) in lieu of XX-8.2(d)(3)(v).

(i) *Notification of certification.* The CO_2 authorized account representative shall submit to the Administrator, REGULATORY AGENCY or its agent, the appropriate EPA Regional Office and the Administrator a written notice of the dates of certification in accordance with section XX-8.4.

(ii) *Certification application.* The CO_2 authorized account representative shall submit to the Administrator, REGULATORY AGENCY or its agent a certification application for each monitoring system. A complete certification application shall include the information specified in 40 CFR 75.63.

(iii) *Provisional certification data.* The provisional certification date for a monitor shall be determined in accordance with 40 CFR 75.20(a)(3). A provisionally certified monitor may be used under the CO_2 budget Trading Program for a period not to exceed 120 days after receipt by the Administrator, REGULATORY AGENCY of the complete certification application for the monitoring system or component thereof under subparagraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of 40 CFR part 75, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator, REGULATORY AGENCY does not invalidate the

provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the Administrator, REGULATORY AGENCY.

(iv) *Certification application approval process.* The Administrator, REGULATORY AGENCY will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under subparagraph (d)(3)(ii) of this section. In the event the Administrator, REGULATORY AGENCY does not issue such a notice within such 120-day period, each monitoring system which meets the applicable performance requirements of 40 CFR part 75 and is included in the certification application will be deemed certified for use under the CO_2 Budget Trading Program.

(a) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR part 75, then the Administrator, REGULATORY AGENCY will issue a written notice of approval of the certification application within 120 days of receipt.

(b) *Incomplete application notice.* If the certification application is not complete, then the Administrator, REGULATORY AGENCY will issue a written notice of incompleteness that sets a reasonable date by which the CO_2 authorized account representative must submit the additional information required to complete the certification application. If the CO_2 authorized account representative does not comply with the notice of incompleteness by the specified date, then the Administrator, REGULATORY AGENCY may issue a notice of disapproval under clause

(d)(3)(iv)*(c)* of this section. The 120 day review period shall not begin before receipt of a complete certification application.

(c) *Disapproval notice.* If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of 40 CFR part 75, or if the certification application is incomplete and the requirement for disapproval under clause (d)(3)(iv)*(b)* of this section is met, then the REGULATORY AGENCY will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator, REGULATORY AGENCY and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in subparagraph (d)(3)(v) of this section for each monitoring system or component thereof, which is disapproved for initial certification.

(d) *Audit decertification.* The REGULATORY AGENCY may issue a notice of disapproval of the certification status of a monitor in accordance with subdivision XX-8.3(b).

(v) *Procedures for loss of certification.* If the REGULATORY AGENCY issues a notice of disapproval of a certification application under clause (d)(3)(iv)*(c)* of this section or a notice of disapproval of certification status under clause (d)(3)(iv)*(d)* of this section, then:

(a) The owner or operator shall substitute the following values for each disapproved monitoring system, for each hour of

unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under 40 CFR 75.20(a)(5)(i) or 40 CFR 75.20(g)(7):

(1) For units using or intending to monitor for CO_2 mass emissions using heat input or for units using the low mass emissions excepted methodology under 40 CFR 75.19, the maximum potential hourly heat input of the unit; or

(2) For units intending to monitor for CO_2 mass emissions using a CO_2 pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO_2 and the maximum potential flow rate of the unit under section 2.1 of appendix A of 40 CFR part 75.

(b) The CO_2 authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with subparagraphs (d)(3)(i) and (ii) of this section; and

(c) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the REGULATORY AGENCY's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) *Initial certification and recertification procedures for low mass emissions units using the excepted methodologies under XX-8.1(c)(2)*. The owner or operator of a unit qualified to use the low mass emissions excepted methodology under XX-8.1(c)(2) shall meet the applicable certification and recertification requirements of 40 CFR 75.19(a)(2), 40 CFR 75.20(h) and section XX-8.2. If the owner or operator of such a unit elects to certify a fuel flow meter system for heat input determinations, the owner

or operator shall also meet the certification and recertification requirements in 40 CFR 75.20(g).

(f) *Certification/recertification procedures for alternative monitoring systems*. The CO_2 authorized account of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the Administrator, REGULATORY AGENCY under Subpart E of 40 CFR part 75 shall comply with the applicable notification and application procedures of 40 CFR 75.20(f).

XX-8.3 Out-of-control periods.

(a) Whenever any monitoring system fails to meet the quality assurance and quality control requirements or data validation requirements of 40 CFR part 75, data shall be substituted using the applicable procedures in Subpart D or appendix D of 40 CFR part 75.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under section XX-8.2 or the applicable provisions of 40 CFR part 75 , both at the time of the initial certification or recertification application submission and at the time of the audit, the REGULATORY AGENCY or Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the REGULATORY AGENCY or the Administrator. By issuing the notice of disapproval, the REGULATORY AGENCY or Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests

for the monitoring system. The owner or operator shall follow the initial certification or recertification procedures in section XX-8.2 for each disapproved monitoring system.

XX-8.4 Notifications.

The CO_2 authorized account representative for a CO_2 budget unit shall submit written notice to the REGULATORY AGENCY and the Administrator in accordance with 40 CFR 75.61.

XX-8.5 Recordkeeping and reporting.

(a) *General provisions.* The CO_2 authorized account representative shall comply with all recordkeeping and reporting requirements in this section, the applicable record keeping and reporting requirements under 40 CFR 75.73 and with the requirements of subdivision XX-2.1(e).

(b) *Monitoring plans.* The owner or operator of a CO_2 budget unit shall submit a monitoring plan in the manner prescribed in 40 CFR 75.62.

(c) *Certification applications.* The CO_2 authorized account representative shall submit an application to the Administrator, REGULATORY AGENCY within 45 days after completing all CO_2 monitoring system initial certification or recertification tests required under section XX-8.2 including the information required under 40 CFR 75.63 and 40 CFR 75.53(g) and (h).

(d) *Quarterly reports.* The CO_2 authorized account representative shall submit quarterly reports, as follows:

(1) The CO_2 authorized account representative shall report the CO_2 mass emissions data for the CO_2 budget unit, in an electronic format prescribed by the Administrator unless otherwise prescribed by the Administrator, REGULATORY AGENCY for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2008, the calendar quarter covering January 1, 2009 through March 31, 2009; or

(ii) For a unit commencing commercial operation on or after July 1, 2008, the calendar quarter corresponding to, the earlier of the date of provisional certification or the applicable deadline for initial certification under subdivision XX-8.1(b) or, unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009.

(2) The CO_2 authorized account representative shall submit each quarterly report to the Administrator, REGULATORY AGENCY or its agent within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in Subpart H of 40 CFR part 75 and 40 CFR 75.64. Quarterly reports shall be submitted for each CO_2 budget unit (or group of units using a common stack), and shall include all of the data and information required in Subpart G of 40 CFR part 75, except for opacity, heat input, NOx, and SO_2 provisions.

(3) *Compliance certification.* The CO_2 authorized account representative shall submit to the Administrator, REGULATORY AGENCY or its agent a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(i) The monitoring data submitted were recorded in accordance with the applicable requirements of this Subpart and 40 CFR part 75, including the quality assurance procedures and specifications;

(ii) For a unit with add-on CO_2 emissions controls and for all hours

where data are substituted in accordance with 40 CFR 75.34(a)(1) , the add-on emissions controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B of 40 CFR part 75 and the substitute values do not systematically underestimate CO_2 emissions; and

(iii) The CO_2 concentration values substituted for missing data under Subpart D of 40 CFR part 75 do not systematically underestimate CO_2 emissions.

XX-8.6 Petitions.

(a) Except as provided in subdivision (c) of this section, the CO_2 authorized account representative of a CO_2 budget unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator under 40 CFR 75.66 and to the REGULATORY AGENCY requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this Subpart only to the extent that the petition is approved in writing by the Administrator, and subsequently approved in writing by the REGULATORY AGENCY.

(b) Petitions for a CO_2 budget unit that is not subject to an Acid Rain emissions limitation.

(1) The CO_2 authorized account representative of a CO_2 budget unit that is not subject to an Acid Rain emissions limitation may submit a petition to the Administrator under 40 CFR 75.66 and to the REGULATORY AGENCY requesting approval to apply an alternative to any requirement of 40 CFR PART 75. Application of an alternative to any requirement of 40 CFR PART 75 is in accordance with this Subpart only to the extent that the petition is approved in writing by the Administrator and subsequently approved in writing by the REGULATORY AGENCY.

(2) In the event that the Administrator declines to review a petition under XX-8.6(b)(1), the CO_2 authorized account representative of a CO_2 budget unit that is not subject to an Acid Rain emissions limitation may submit a petition to the REGULATORY AGENCY requesting approval to apply an alternative to any requirement of XX-8. That petition shall contain all of the relevant information specified in 40 CFR 75.66. Application of an alternative to any requirement of XX-8 is in accordance with XX-8 only to the extent that the petition is approved in writing by the REGULATORY AGENCY.

(c) The CO_2 authorized account representative of a CO_2 budget unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator under 40 CFR 75.66 and to the REGULATORY AGENCY requesting approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of 40 CFR 75.72 or a CO_2 concentration CEMS used under 40 CFR 75.71(a)(2). Application of an alternative to any such requirement is in accordance with this Subpart only to the extent the petition is approved in writing by the Administrator and subsequently approved in writing by the REGULATORY AGENCY.

XX-8.7 CO_2 budget units that co-fire eligible biomass.

(a) The CO_2 authorized account representative of a CO_2 budget unit that co-fires eligible biomass as a compliance mechanism under XX shall report the following information to the REGULATORY AGENCY or its agent for each calendar quarter:

(1) For each shipment of solid eligible biomass fuel fired at the CO_2 budget unit, the total eligible biomass fuel input, on an as-fired basis, in pounds;

(2) For each shipment of solid eligible biomass fuel fired at the CO_2 budget unit, the moisture content, on an as-fired basis, as a fraction by weight;

(3) For each distinct type of gaseous eligible biomass fuel fired at the CO_2 budget unit, the density of the biogas, on an as-fired basis, in pounds per standard cubic foot;

(4) For each distinct type of gaseous eligible biomass fuel fired at the CO_2 budget unit, the moisture content of the biogas, as a fraction by total weight;

(5) For each distinct type of gaseous eligible biomass fuel fired at the CO_2 budget unit, the total eligible biomass fuel input, in standard cubic feet;

(6) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, the dry basis carbon content of the fuel type, as a fraction by dry weight;

(7) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, the dry basis higher heating value, in MMBtu per dry pound;

(8) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, the total dry basis eligible biomass fuel input, in pounds, calculated in accordance with XX-8.7(b);

(9) The total amount of CO_2 emitted from the $CO2$ budget unit due to firing eligible biomass fuel, in tons, calculated in accordance with XX-8.7(c);

(10) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, the total eligible biomass fuel heat input, in MMBtu, calculated in accordance with XX-8.7(d)(1).

(11) The total amount of heat input to the CO_2 budget unit due to firing eligible biomass fuel, in MMBtu, calculated in accordance with XX-8.7(d)(2);

(12) Description and documentation of monitoring technology employed, and description and documentation of fuel sampling methodology employed, including sampling frequency; and

(13) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, chemical analysis, including heating value and carbon content.

(b) An owner or operator of a CO_2 budget unit shall calculate and submit to the REGULATORY AGENCY or its agent on a quarterly basis the total dry weight for each distinct type of eligible biomass fired by the CO_2 budget unit during the reporting quarter. The total dry weight shall be determined for each fuel type as follows:

(1) For solid fuel types:

$$F_j = \sum_{i=1}^{m} (1 - M_i) \times F_i$$

Where:

F_j = Total eligible biomass dry basis fuel input (lbs) for fuel type j;

F_i = Eligible biomass as fired fuel input (lbs) for fired shipment i;

M_i = Moisture content (fraction) for fired shipment i;

i = Fired fuel shipment;

j = Fuel type; and

m = Number of shipments.

(2) For gaseous fuel types:

$$F_j = D_j \times V_j \times (1 - M_j)$$

Where:

F_j = Total eligible biomass dry basis fuel input (lbs) for fuel type j;

D_j = Density of biogas (lbs/scf) for fuel type j;

V_j = Total volume (scf) for fuel type j;

M_j = Moisture content (fraction) for fuel type j;

j = Fuel type.

(c) CO_2 emissions due to firing of eligible biomass shall be determined as follows:

(1) For any full calendar quarter during which no fuel other than eligible biomass is combusted at the CO_2 budget unit, as measured and recorded in accordance with XX-8.1 through XX-8.6 ; or

For any full calendar quarter during which fuels other than eligible biomass are combusted at the CO_2 budget unit, as determined using the following equation:

$$CO_2\ tons = \sum_{j=1}^{n} F_j \times C_j \times O_j \times \frac{44}{12} \times 0.0005$$

Where:

CO_2 tons = CO_2 emissions due to firing of eligible biomass for the reporting quarter;

F_j = Total eligible biomass dry basis fuel input (lbs) for fuel type j, as calculated in XX-8.7(b);

C_j = Carbon fraction (dry basis) for fuel type j;

O_j = Oxidation factor for eligible biomass fuel type j, derived for solid fuels based on the ash content of the eligible biomass fired and the carbon content of this ash, as determined pursuant to XX-8.7(a)(12); for gaseous eligible biomass fuels, a default oxidation factor of 0.995 may be used;

44/12 = The number of tons of carbon dioxide that are created when one ton of carbon is combusted (44/12);

0.0005 = The number of short tons which is equal to one pound;

j = Fuel type; and

n = Number of distinct fuel types.

(d) Heat input due to firing of eligible biomass for each quarter shall be determined as follows:

(1) For each distinct fuel type:

$$H_j = F_j \times HHV_j$$

Where:

H_j = Heat input (MMBtu) for fuel type j;

F_j = Total eligible biomass dry basis fuel input (lbs) for fuel type j, as calculated in XX-8.7(b);

HHV_j = Higher heating value (MMBtu/lb), dry basis, for fuel type j, as determined through chemical analysis; and

j = fuel type.

(2) For all fuel types:

$$Heat\ input\ MMBtu = \sum_{i=1}^{n} H_j$$

Where:

H_j = Heat input (MMBtu) for fuel type j;

j = fuel type; and

n = number of distinct fuel types.

(e) Fuel sampling methods and fuel sampling technology shall be consistent with the New York State Renewable Portfolio Standard Biomass Guidebook, September 2011.

XX-8.8 Additional requirements to provide output data.

(a) A CO_2 budget unit in a state that requires the use of information submitted to the Independent System Operator (ISO) to document megawatt-hours (MWh) the CO_2 budget unit produces shall submit to the REGULATORY AGENCY or its agent the same MWh value submitted to the ISO and a statement certifying that the MWh of electrical output reported reflects the total actual electrical output for all CO_2 budget units at the facility used by the ISO to determine settlement resources of energy market participants.

(b) A CO_2 budget unit in a state that requires gross output to be used that also reports gross hourly MW to the Administrator, shall use the same electronic data report (EDR) gross output (in MW), as submitted to the Administrator, for the hour times operating time in the hour, added for all hours in a year. A CO_2 budget unit that does not report gross hourly MW to the Administrator shall submit to the REGULATORY AGENCY or its agent information in accordance with paragraph XX-8.8(e)(1).

(c) A CO_2 budget unit in a state that requires net electrical output, shall submit to the REGULATORY AGENCY or its agent information in accordance with paragraph XX-8.8(e)(1). A CO_2 budget source whose electrical output is not used in ISO energy market settlement determinations shall propose to the REGULATORY AGENCY a method for quantification of net electrical output.

(d) CO_2 budget sources selling steam should use billing meters to determine net steam output. A CO_2 budget source whose steam output is not measured by billing meters or whose steam output is combined with output from a non-CO_2 budget unit prior to measurement by the billing meter shall propose to the REGULATORY AGENCY an alternative method for quantification of net steam output. If data for steam output is not

available, the CO_2 budget source may report heat input providing useful steam output as a surrogate for steam output.

(e) *Monitoring.* The owner or operator of each CO_2 budget unit, in a state that requires the CO_2 budget unit's net output, must meet the following requirements. Each CO_2 budget source must submit an output monitoring plan. The output monitoring plan must include a description and diagram as stated below.

(1) Submit a diagram of the electrical and/or steam system for which output is being monitored, specifically including the following.

If the CO_2 budget unit monitors net electric output, the diagram should contain all CO_2 budget units and all generators served by each CO_2 budget unit and the relationship between CO_2 budget units and generators. If a generator served by a CO_2 budget unit is also served by a non-affected unit, the non-affected unit and its relationship to each generator should be indicated on the diagram as well. The diagram should indicate where the net electric output is measured and should include all electrical inputs and outputs to and from the plant. If net electric output is determined using a billing meter, the diagram should show each billing meter used to determine net sales of electricity and should show that all electricity measured at the point of sale is generated by the CO_2 budget units.

(i) If the CO_2 budget unit monitors net thermal output, the diagram should include all steam or hot water coming into the net steam system, including steam from CO_2 budget units and non-affected units, and all exit points of steam or hot water from the net steam system. In addition, each input and output stream will have an estimated temperature, pressure and phase indicator, and an enthalpy in Btu/lb. The diagram of the net steam system should identify all useful loads, house loads, parasitic loads, any other steam loads and all boiler feedwater returns. The diagram will represent all energy losses in the system as either usable or

unusable losses. The diagram will also indicate all flow meters, temperature or pressure sensors or other equipment used to calculate gross thermal output. If a sales agreement is used to determine net thermal output, the diagram should show the monitoring equipment used to determine the sales of steam.

(2) Submit a description of each output monitoring system. The description of the output monitoring system should include a written description of the output system and the equations used to calculate output. For net thermal output systems descriptions and justifications of each useful load should be included.

(3) Submit a detailed description of all quality assurance/quality control activities that will be performed to maintain the output system in accordance with subdivision XX-8.8(g).

(4) Submit documentation supporting any output value(s) to be used as a missing data value should there be periods of invalid output data. The missing data output value must be either zero or an output value that is likely to be lower than a measured value and that is approved as part of the monitoring plan required under this subdivision.

(f) *Initial certification*. A certification statement must be submitted by the CO_2 authorized account representative stating that either the output monitoring system consists entirely of billing meters or that the output monitoring system meets one of the accuracy requirements for non-billing meters at paragraph (2) of this subdivision. This statement may be submitted with the certification application required under subdivision XX-8.5(c).

(1) *Billing meters*. The billing meter must record the electric or thermal output. Any electric or thermal output values that the facility reports must be the same as the values used in billing for the output. Any output measurement equipment used as a billing meter in commercial transactions requires no additional certification or testing.

(2) *Non-billing meters*. For non-billing meters, the output monitoring system must either meet an accuracy of within 10% of the reference value, or each component monitor for the output system must meet an accuracy of within 3% of the full scale value, whichever is less stringent.

(i) *System approach to accuracy*. The system approach to accuracy must include a determination of how the system accuracy of 10% is achieved using the individual components in the system and should include data loggers and any watt meters used to calculate the final net electric output data and/or any flow meters for steam or condensate, temperature measurement devices, absolute pressure measurement devices, and differential pressure devices used for measuring thermal energy.

(ii) *Component approach to accuracy*. If testing a piece of output measurement equipment shows that the output readings are not accurate to within 3.0 percent of the full scale value, then the equipment should be repaired or replaced to meet that requirement. Data shall remain invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test.

(g) *Ongoing QA/QC*. Ongoing quality assurance/quality control activities must be performed in order to maintain the output system.

(1) *Billing meters*. In the case where billing meters are used to determine output, no QA/QC activities beyond what are already performed are required.

(2) *Non-billing meters*. Certain types of equipment such as potential transformers, current transformers, nozzle and venturi type meters, and the primary element of an orifice plate only require an initial certification of calibration and do not require periodic recalibration unless the equipment is physically changed. However, the pressure and temperature

transmitters accompanying an orifice plate will require periodic retesting. For other types of equipment, either recalibrate or re-verify the meter accuracy at least once every two years (i.e., every eight calendar quarters), unless a consensus standard allows for less frequent calibrations or accuracy tests. For non- billing meters, the output monitoring system must either meet an accuracy of within 10% of the reference value, or each component monitor for the output system must meet an accuracy of within 3% of the full scale value, whichever is less stringent. If testing a piece of output measurement equipment shows that the output readings are not accurate to within 3.0 percent of the full scale value, then the equipment should be repaired or replaced to meet that requirement.

(3) *Out-of-control periods*. If testing a piece of output measurement equipment shows that the output readings are not accurate to the certification value, data remain invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test. All invalid data shall be replaced by either zero or an output value that is likely to be lower than a measured value and that is approved as part of the monitoring plan required under subdivision XX-8.8(e).

(h) *Recordkeeping and reporting.*

(1) *General provisions.* The CO_2 authorized account representative shall comply with all recordkeeping and reporting requirements in this section and with the requirements of subdivisions XX-1.5(e) and XX-2.1(e).

(2) *Recordkeeping.* Facilities shall retain data used to monitor, determine, or calculate net generation for ten years.

(3) *Annual reports.* The CO_2 authorized account representative shall submit annual output reports, as follows. The data must be sent both electronically and in hardcopy by March 1 for the immediately preceding

calendar year to the REGULATORY AGENCY or its agent. The annual report shall include unit level MWh, all useful steam output and a certification statement from the CO_2 authorized account representative stating the following,

"I am authorized to make this submission on behalf of the owners and operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

Subpart XX-9 Auction of CO_2 CCR and ECR allowances

XX-9.1 Purpose

The following rules shall apply to each allowance auction. The REGULATORY AGENCY or its agent may specify additional information in the auction notice for each auction. Such additional information may include the time and location of the auction, auction rules, registration deadlines, and any additional information deemed necessary or useful.

XX-9.2 General Requirements

(a) The REGULATORY AGENCY or its agent shall include the following information in the auction notice for each auction:

(1) The number of CO_2 allowances offered for sale at the auction, not including any CO_2 CCR allowances;

(2) The number of CO_2 CCR allowances that will be offered for sale at the auction if the condition of paragraph (b)(1) of this section is met;

(3) The minimum reserve price for the auction; and

(4) The CCR trigger price for the auction.

(5) The maximum number of CO_2 allowances that may be withheld from sale at the auction if the condition of paragraph (d) (1) of this section is met;

(6) The ECR trigger price for the auction.

(b) The REGULATORY AGENCY or its agent shall follow these rules for the sale of CO_2 CCR allowances:

(1) CO_2 CCR allowances shall only be sold at an auction in which total demand for allowances, above the CCR trigger price, exceeds the number of CO_2 allowances available for purchase at the auction, not including any CO_2 CCR allowances.

(2) If the condition of paragraph (1) of this subdivision is met at an auction, then the number of CO_2 CCR allowances offered for sale by the REGULATORY AGENCY or its agent at the auction shall be equal to the number of CO_2 CCR allowances in the RELEVANT STATE AUCTION ACCOUNT at the time of the auction.

(3) After all of the CO_2 CCR allowances in the RELEVANT STATE AUCTION ACCOUNT have been sold in a given calendar year, no additional CO_2 CCR allowances will be sold at any auction for the remainder of that calendar year, even if the condition of paragraph (1) of this subdivision is met at an auction; and

(4) At an auction in which CO_2 CCR allowances are sold, the reserve price at for the auction shall be the CCR trigger price.

(5) If the condition of paragraph (1) of this subdivision is not satisfied, no CO_2

CCR allowances shall be offered for sale at the auction, and the reserve price for the auction shall be equal to the minimum reserve prices.

(c) The REGULATORY AGENCY or its agent shall implement the reserve price in the following manner:

(1) No allowances shall be sold at any auction for a price below the reserve price for that auction; and

(2) If the total demand for allowances at an auction is less than or equal to the total number of allowances made available for sale in that auction, then the auction clearing price for the auction shall be the reserve price.

(d) The REGULATORY AGENCY or its agent shall follow these rules for the withholding of CO_2 ECR allowances from an auction:

(1) CO_2 ECR allowances shall only be withheld from an auction if the demand for allowances would result in an auction clearing price that is less than the ECR trigger price prior to the withholding from the auction of any ECR allowances.

(2) If the condition in paragraph (1) of this subdivision is met at an auction, then the maximum number of CO_2 ECR allowances that may be withheld from that auction will be equal to the quantity shown in section 5.3(e)(1) Table 4 minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the RELEVANT STATE ECR ACCOUNT.

Subpart XX-10 CO_2 Emissions Offset Projects

XX-10.1 Purpose.

The REGULATORY AGENCY will provide for the award of CO_2 offset allowances to sponsors of CO_2 emissions offset projects that have reduced or avoided atmospheric

loading of CO_2, CO_2 equivalent or sequestered carbon as demonstrated in accordance with the applicable provisions of this Subpart. The requirements of this Subpart seek to ensure that CO_2 offset allowances awarded represent CO_2 equivalent emission reductions or carbon sequestration that are real, additional, verifiable, enforceable, and permanent within the framework of a standards-based approach. Subject to the relevant compliance deduction limitations of paragraph XX-6.5(a)(3), CO_2 offset allowances may be used by any CO_2 budget source for compliance purposes.

XX-10.2 Definitions.

(a) *Anaerobic digester*. A device that promotes the decomposition of organic material to simple organics and gaseous biogas products, in the absence of elemental oxygen, usually accomplished by means of controlling temperature and volume, and including a methane recovery system.

(b) *Anaerobic digestion*. The decomposition of organic material including manure brought about through the action of microorganisms in the absence of elemental oxygen.

(c) *Anaerobic storage*. Storage of organic material in an oxygen-free environment, or under oxygen-free conditions, including but not limited to, holding tanks, ponds, and lagoons.

(d) *ANSI*. American National Standards Institute.

(e) *Biogas*. Gas resulting from the decomposition of organic matter under anaerobic conditions. The principle constituents are methane and carbon dioxide.

(f) *CO_2e*. CO_2e means carbon dioxide equivalent.

(g) *Conflict of interest*. A situation that may arise with respect to an individual in relation to any specific project sponsor, CO_2 emissions offset project or category of

offset projects, such that the individual's other activities or relationships with other persons or organizations render or may render the individual incapable of providing an impartial certification opinion, or otherwise compromise the individual's objectivity in performing certification functions.

(h) *Cooperating regulatory agency*. A regulatory agency in a state or United States jurisdiction that is not a participating state that has entered into a memorandum of understanding with the appropriate regulatory agencies of all participating states to carry out certain obligations relative to CO_2 emissions offset projects in that state or United States jurisdiction, including but not limited to the obligation to perform audits of offset project sites, and report violations of this Subpart.

(i) *Forest offset project*. An offset project involving reforestation, improved forest management, or avoided conversion.

(j) *Forest offset project data report*. The report prepared by a project sponsor each year that provides the information and documentation required by this Subpart or the forest offset protocol.

(k) *Forest offset protocol*. The protocol titled "Regional Greenhouse Gas Initiative Offset Protocol U.S. Forest Projects", published by the participating states on June 12, 2013.

(l) *Independent verifier*. An individual that has been approved by the REGULATORY AGENCY or its agent to conduct verification activities.

(m) *Intentional Reversal*. Any reversal caused by a forest owner's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the area within the offset project boundary

(n) *Market penetration rate*. A measure of the diffusion of a technology, product, or practice in a defined market, as represented by the percentage of annual sales for a

product or practice, or as a percentage of the existing installed stock for a product or category of products, or as the percentage of existing installed stock that utilizes a practice. The REGULATORY AGENCY may determine an appropriate market definition and market penetration metric for a category of technology, product or practice, and may issue guidance specifying the technologies, products or practices that meet a specified market penetration rate.

(o) *Offset project*. An offset project includes all equipment, materials, items, or actions directly related to the reduction of CO_2 equivalent emissions or the sequestration of carbon specified in a consistency application submitted pursuant to section XX-10.4. Equipment, materials, items, or actions unrelated to an offset project reduction of CO_2 equivalent emissions or the sequestration of carbon, but occurring at a location where an offset project occurs, shall not be considered part of an offset project, unless specified at section XX-10.5.

(p) *Permanently retired*. A greenhouse gas allowance or credit has been "permanently retired" if it has been placed in a retirement account controlled by the jurisdiction that generated the allowance or credit, or has been placed in an allowance retirement account controlled by the REGULATORY AGENCY, or is otherwise determined by the REGULATORY AGENCY to have been rendered unusable.

(q) *Project commencement*. For an offset project involving physical construction, other work at an offset project site, or installation of equipment or materials, the date of the beginning of such activity. For an offset project that involves the implementation of a management activity or protocol, the date on which such activity is first implemented or such protocol first utilized. For an offset project involving reforestation, improved forest management, or avoided conversion, the date specified in section 3.2 of the forest offset protocol.

(r) *Regional-type anaerobic digester*. An anaerobic digester using feedstock from more than one agricultural operation, or importing feedstock from more than one

agricultural operation. Also commonly referred to as a "community digester" or "centralized digester."

(s) *Renewable portfolio standard*. A statutory or regulatory requirement that a load-serving entity provide a certain portion of the electricity it supplies to its customers from renewable energy sources, or any other statutory or regulatory requirement that a certain portion of electricity supplied to the electricity grid be generated from renewable energy sources.

(t) *Reporting Period*. The period of time covered by a forest offset project data report. The first reporting period for an offset project in an initial crediting period may consist of 6 to 24 consecutive months; all subsequent reporting periods in an initial crediting and all reporting periods in any renewed crediting period must consist of 12 consecutive months.

(u) *Reversal*. A GHG emission reduction or GHG removal enhancement for which CO_2 offset allowances have been issued that is subsequently released or emitted back into the atmosphere due to any intentional or unintentional circumstance.

(v) *System benefit fund*. Any fund collected directly from retail electricity or natural gas ratepayers.

(w) *Total solids*. Total solids are the total of all solids in a sample. They include the total suspended solids, total dissolved solids, and volatile suspended solids.

(x) *Transmission and/or distribution entity*. The assets and equipment used to transmit and distribute electricity from an electric generator to the electrical load of a customer. Includes all related assets and equipment located within the service territory of the entity, defined as the service territory of a load-serving entity specified by the applicable state regulatory agency.

(y) *Unintentional Reversal*. Any reversal, including, but not limited to, wildfires, insects, or disease that is not the result of the forest owner's negligence, gross negligence, or willful intent.

(z) *Verification*. The verification by an independent verifier that certain parts of a CO_2 emissions offset project consistency application and/or measurement, monitoring or verification report conforms to the requirements of this Subpart.

(aa) *Volatile solids*. The fraction of total solids that is comprised primarily of organic matter as defined in U.S.EPA Method Number 160.4, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020).

XX-10.3 General requirements.

(a) *Eligible CO_2 emissions offset projects*. To qualify for the award of CO_2 offset allowances, offset projects shall satisfy all the applicable requirements of XX-10.

(1) *Offset project types*. The following types of offset projects are eligible for the award of CO_2 offset allowances.

(i) Landfill methane capture and destruction;

(ii) Sequestration of carbon due to reforestation, improved forest management, or avoided conversion;

(iii) Avoided methane emissions from agricultural manure management operations.

(2) *Offset project locations*.

(i) To qualify for the award of CO_2 allowances under XX-10, eligible offset projects may be located in any of the following locations:

(a) In **[STATE]**; and

(b) In any state or United States jurisdiction in which a cooperating regulatory agency has entered into a memorandum of understanding with the appropriate regulatory agencies of all participating states to carry out

certain obligations relative to CO_2 emissions offset projects in that state or U.S. jurisdiction, including but not limited to the obligation to perform audits of offset project sites, and report violations of XX-10.

(ii) Projects located (in whole or in part) in one or more participating states are not eligible for CO_2 offset allowances under XX-10 unless more of the CO_2 equivalent emissions reduction or carbon sequestration due to the offset project is projected to occur in **[STATE]** than in any other participating state.

(b) *Project sponsor*. Any person may act as the sponsor of an eligible CO_2 emissions offset project, provided that person meets the requirements at section XX-10.4.

(c) *General additionality requirements.* Except as provided with respect to specific offset project standards in section XX-10.5, the following general requirements shall apply.

(1) CO_2 offset allowances shall not be awarded to an offset project that is required pursuant to any local, state or federal law, regulation, or administrative or judicial order. If an offset project receives a consistency determination under section XX-10.4 and is later required by local, state or federal law, regulation, or administrative or judicial order, then the offset project shall remain eligible for the award of CO_2 offset allowances until the end of its current allocation period but its eligibility shall not be extended for an additional allocation period.

(2) CO_2 offset allowances shall not be awarded to an offset project that includes an electric generation component, unless the project sponsor transfers legal rights to any and all attribute credits (other than the CO_2 offset allowances awarded under section XX-10.7) generated from the operation of the offset project that may be used for compliance with a

renewable portfolio standard or other regulatory requirement, to the REGULATORY AGENCY or its agent.

(3) CO_2 offset allowances shall not be awarded to an offset project that receives funding or other incentives from any system benefit fund, or funds or other incentives provided through the consumer benefit or strategic energy purpose allocation required pursuant to subdivision XX-5.3(b).

(4) CO_2 offset allowances shall not be awarded to an offset project that is awarded credits or allowances under any other mandatory or voluntary greenhouse gas program, except ~~for~~ as described in Section XX-10.5(b)(10).

(d) *Maximum allocation periods for CO_2 emissions offset projects*.

(1) *Maximum allocation periods*. Except as provided in paragraph (d)(2) of this section, the REGULATORY AGENCY may award CO_2 offset allowances under section XX-10.7 for an initial 10-year allocation period. At the end of the initial 10-year allocation period, the REGULATORY AGENCY may award CO_2 offset allowances for a second 10-year allocation period, provided the offset sponsor has submitted a consistency application pursuant to section XX-10.4 prior to the expiration of the initial allocation period, and the REGULATORY AGENCY has issued a consistency determination pursuant to paragraph XX-10.4(e)(2).

(2) *Maximum allocation period for involving reforestation, improved forest management, or avoided conversion*. The REGULATORY AGENCY may award CO_2 offset allowances under section XX-10.7 for any project involving reforestation, improved forest management, or avoided conversion offset project for an initial 25-year allocation period. At the end of the initial 25-year allocation period, or any subsequent crediting period, the REGULATORY AGENCY may award CO_2 offset allowances for a subsequent 25-year allocation period, provided the offset sponsor has

submitted a consistency application for the offset project pursuant to section XX-10.4 prior to the expiration of the initial allocation period, and the REGULATORY AGENCY has issued a consistency determination pursuant to paragraph XX-10.4(e)(2).

(e) *Offset project audit*. Project sponsors shall provide, in writing, an access agreement to the REGULATORY AGENCY granting the REGULATORY AGENCY or its agent access to the physical location of the offset project to inspect for compliance with this Subpart. For offset projects located in any state or other U.S. jurisdiction that is not a participating state, project sponsors shall also provide, in writing, an access agreement to the REGULATORY AGENCY granting the cooperating regulatory agency with access to the physical location of the offset project to inspect for compliance with this Subpart.

(f) *Ineligibility due to noncompliance*.

(1) If at any time the REGULATORY AGENCY determines that a project sponsor has not complied with the requirements of this Subpart, then the REGULATORY AGENCY may revoke and retire any and all CO_2 offset allowances in the project sponsor's account.

(2) If at any time the REGULATORY AGENCY determines that an offset project does not comply with the requirements of this Subpart, then the REGULATORY AGENCY may revoke any approvals it has issued relative to an offset project.

XX-10.4 Application process.

(a) *Establishment of general account.* The sponsor of an offset project must establish a general account under subdivision XX-6.2(b). All submissions to the REGULATORY AGENCY required for the award of CO_2 offset allowances under this Subpart must be from the CO_2 authorized account representative for the general

account of the sponsor of the relevant offset project, herein referred to as "project sponsor."

(b) *Consistency application deadlines.*

(1) For offset projects not involving reforestation, improved forest management, or avoided conversion the consistency application must be submitted by the date that is 6 months after the offset project is commenced.

(2) For offset projects involving reforestation, improved forest management, or avoided conversion the consistency application must be submitted by the date that is one year after the offset project is commenced, except for as described in Section XX 10.5(c)(9).

(3) Any consistency application that fails to meet the deadlines of this subdivision will result in the denial of the consistency application and the continued ineligibility of the subject offset project.

(c) *Consistency application contents*.

(1) For an offset project, the consistency application must include the following information.

(i) The project's sponsor's name, address, e-mail address, telephone number, facsimile transmission number, and account number.

(ii) The offset project description as required by the relevant provisions of section XX-10.5.

(iii) A demonstration that the offset project meets all applicable requirements set forth in this Subpart.

(iv) The emissions baseline determination as required by the relevant provisions of section XX-10.5.

(v) An explanation of how the projected reduction or avoidance of atmospheric loading of CO_2 or CO_2 equivalent or the sequestration

of carbon is to be quantified, monitored, and verified as required by the relevant provisions of section XX-10.5.

(vi) A completed consistency application agreement that reads as follows:

"The undersigned project sponsor recognizes and accepts that the application for, and the receipt of, CO_2 offset allowances under the CO_2 Budget Trading Program is predicated on the project sponsor following all the requirements of Subpart XX-10. The undersigned project sponsor holds the legal rights to the offset project, or has been granted the right to act on behalf of a party that holds the legal rights to the offset project. I understand that eligibility for the award of CO_2 offset allowances under Subpart XX-10 is contingent on meeting the requirements of Subpart XX-10. I authorize the REGULATORY AGENCY or its agent to audit this offset project for purposes of verifying that the offset project, including the monitoring and verification plan, has been implemented as described in this application. I understand that this right to audit shall include the right to enter the physical location of the offset project. I submit to the legal jurisdiction of **[RGGI PARTICIPATING STATE]**."

(vii) A statement and certification report signed by the offset project sponsor certifying that all offset projects for which the sponsor has received CO_2 offset allowances under this Subpart (or similar provisions in the rules of other participating states), under the sponsor's ownership or control (or under the ownership or control of any entity which controls, is controlled by, or has common control with the sponsor) are in compliance with all applicable requirements of the CO_2 Budget Trading Program in all participating states.

(vii) A verification report and certification statement signed by an independent verifier accredited pursuant to section XX-10.6 that

expresses that the independent verifier has reviewed the entire application and evaluated the following in relation to the applicable requirements at sections XX-10.3 and XX-10.5, and any applicable guidance issued by the REGULATORY AGENCY.

(a) The adequacy and validity of information supplied by the project sponsor to demonstrate that the offset project meets the applicable eligibility requirements of sections XX-10.3 and XX-10.5.

(b) The adequacy and validity of information supplied by the project sponsor to demonstrate baseline emissions pursuant to the applicable requirements at section XX-10.5.

(c) The adequacy of the monitoring and verification plan submitted pursuant to the applicable requirements at section XX-10.5.

(d) Such other evaluations and statements as may be required by the REGULATORY AGENCY.

(ix) Disclosure of any voluntary or mandatory programs, other than the CO_2 Budget Trading Program, to which greenhouse gas emissions data related to the offset project has been, or will be reported.

(x) For offset projects located in a state or United States jurisdiction that is not a participating state, a demonstration that the project sponsor has complied with all requirements of the cooperating regulatory agency in the state or United States jurisdiction where the offset project is located.

(2) Consistency applications shall be submitted in a format approved by the REGULATORY AGENCY.

(d) Consistency applications may not be submitted to **[REGULATORY AGENCY]** if a consistency application has already been submitted for the same project, or any portion of the same project, in another participating state, unless the consistency

application was rejected by another participating state solely because more of the CO_2 equivalent emissions reduction or carbon sequestration due to the offset project is projected to occur in **[STATE]** than in any other participating state.

(e) *REGULATORY AGENCY action on consistency applications.*

(1) *Completeness determination*. Within 30 days following receipt of the consistency application filed pursuant to subdivision (b) of this section, the REGULATORY AGENCY will notify the project sponsor whether the consistency application is complete. A complete consistency application is one that is in an approved form and is determined by the REGULATORY AGENCY to be complete for the purpose of commencing review of the consistency application. In no event shall a completeness determination prevent the REGULATORY AGENCY from requesting additional information in order to enable the REGULATORY AGENCY to make a consistency determination under paragraph (2) of this subdivision.

(2) *Consistency determination*. Within 90 days of making the completeness determination under paragraph (1) of this subdivision, the REGULATORY AGENCY will issue a determination as to whether the offset project is consistent with the requirements of sections XX-10.3 and XX-10.4 and the requirements of the applicable offset project standard of section XX-10.5. For any offset project found to lack consistency with these requirements, the REGULATORY AGENCY will inform the project sponsor of the offset project's deficiencies.

XX-10.5 CO_2 emissions offset project standards.

(a) *Landfill methane capture and destruction.* To qualify for the award of CO_2 offset allowances under XX-10, offset projects that capture and destroy methane from landfills shall meet the requirements of XX-10.5(a) and all other applicable requirements of XX-10.

(1) *Eligibility.* Eligible offset projects shall occur at landfills that are not subject to the New Source Performance Standards (NSPS) for municipal solid waste landfills, 40 CFR Part 60, Subpart Cc and Subpart WWW.

(2) *Offset project description*. The offset project sponsor shall provide a detailed narrative of the offset project actions to be taken, including documentation that the offset project meets the eligibility requirements of paragraph (1) of this subdivision.

The project narrative shall include the following information.

(i) Owner and operator of the offset project;

(ii) Location and specifications of the landfill where the offset project will occur, including waste in place;

(iii) Owner and operator of the landfill where the offset project will occur; and

(iv) Specifications of the equipment to be installed and a technical schematic of the offset project.

(3) *Emissions baseline determination*. The emissions baseline shall represent the potential fugitive landfill emissions of CH_4 (in tons of CO_2e), as represented by the CH_4 collected and metered for thermal destruction as part of the offset project, and calculated in accordance with this paragraph.

$$\text{Emissions (tons } CO_2e) = \frac{V \times M \times (1-OX) \times GWP}{2000}$$

Where:

V = volume of CH_4 collected (ft^3);

M = Mass of CH_4 per cubic foot (0.04246 lbs/ft^3 default value at 1 atmosphere, 20^o C);

OX= Oxidation factor (0.10), representing estimated portion of collected CH_4 that would have eventually oxidized to CO_2 if not collected; and

GWP = CO_2e global warming potential of CH_4 (28).

(4) *Calculating emissions reductions*. Emissions reductions shall be determined based on potential fugitive CH_4 emissions that would have occurred at the landfill if metered CH_4 collected from the landfill for thermal destruction as part of the offset project was not collected and destroyed. CO_2e emissions reductions shall be calculated as follows:

$$\text{Emissions Reductions (tons } CO_2e) = \frac{V \times M \times (1-OX) \times C_{ef} \times GWP}{2000}$$

Where:

V = Volume of CH_4 collected (ft_3);

M = Mass of CH_4 per cubic foot (0.04246 lbs/ft^3 default value at 1 atmosphere and 20^o C);

OX= Oxidation factor (0.10), representing estimated portion of collected CH_4 that would have eventually oxidized to CO_2 if not collected;

C_{ef} = Combustion efficiency of methane control technology (0.98); and

GWP = CO_2e global warming potential of CH_4 (28).

(5) *Monitoring and verification requirements*. Offset projects shall employ a landfill gas collection system that provides continuous metering and data computation of landfill gas volumetric flow rate and CH_4 concentration. Annual monitoring and verification reports shall include monthly volumetric flow rate and CH_4 concentration data, including documentation that the

CH_4 was actually supplied to the combustion source. Monitoring and verification is also subject to the following requirements.

(i) The project sponsor shall submit a monitoring and verification plan as part of the consistency application that includes a quality assurance and quality control program associated with equipment used to determine landfill gas volumetric flow rate and CH_4 composition. The monitoring and verification plan shall also include provisions for ensuring that measuring and monitoring equipment is maintained, operated, and calibrated based on manufacturer recommendations, as well as provisions for the retention of maintenance records for audit purposes. The monitoring and verification plan shall be certified by an independent verifier accredited pursuant to section XX-10.6.

(ii) The project sponsor shall annually verify landfill gas CH_4 composition through landfill gas sampling and independent laboratory analysis using applicable U.S. Environmental Protection Agency laboratory test methods.

(b) *Sequestration of carbon due to reforestation, improved forest management, or avoided conversion.* To qualify for the award of CO_2 offset allowances under XX-10, offset projects that involve reforestation, improved forest management, or avoided conversion shall meet all requirements of XX-10.5(b) and the forest offset protocol, and all other applicable requirements of XX-10.

(1) *Eligibility*. Eligible forest offset projects shall satisfy all eligibility requirements of the forest offset protocol and this Subpart.

(2) *Offset project descriptio*n. The offset project sponsor shall provide a detailed narrative of the offset project actions to be taken, including documentation that the offset project meets the eligibility requirements of paragraph (1) of this subdivision. The offset project description must include all information identified in sections 8.1 and 9.1 of the forest offset

protocol, and any other information deemed necessary by the REGULATORY AGENCY.

(3) *Carbon sequestration baseline determination*. Baseline onsite carbon stocks shall be determined as required by sections 6.1.1, 6.1.2, 6.2.1, 6.2.2, 6.2.3, 6.3.1, and 6.3.2 of the forest offset protocol, as applicable.

(4) *Calculating carbon sequestered*. Net GHG reductions and GHG removal enhancements shall be calculated as required by section 6 of the forest offset protocol. The project's risk reversal rating shall be calculated using the forest offset protocol Determination of a Forest Project's Reversal Risk Rating assessment worksheet.

(5) *Monitoring and verification requirements*. Monitoring and verification is subject to the following requirements.

(i) Monitoring and verification reports shall include all forest offset project data reports submitted to the REGULATORY AGENCY, including any additional data required by section 9.2.2 of the forest offset protocol.

(ii) The consistency application shall include a monitoring and verification plan certified by an independent verifier accredited pursuant to section XX-10.6. The monitoring and verification plan shall consist of a forest carbon inventory program, as required by section 8.1 of the forest offset protocol.

(iii) Monitoring and verification reports shall be submitted not less than every six years, except that the first monitoring and verification report for reforestation projects must be submitted within twelve years of project commencement

(6) *Forest Offset Project Data Reports*. A project sponsor shall submit a forest offset Project data report to the REGULATORY AGENCY for each reporting period. Each forest offset project data report must cover a single reporting period. Reporting periods must be contiguous; there must be no gaps in reporting once the first reporting period has commenced.

(7) Prior to the award of CO_2 offset allowances pursuant to XX-10.7, or to any surrender of allowances pursuant to XX-10.5(b)(8)(ii)(c), any quantity expressed in metric tons, or metric tons of CO_2 equivalent, shall be converted to tons using the conversion factor specified in XX-1.2.

(8) *Carbon sequestration permanence*. The offset project shall meet the following requirements to address reversals of sequestered carbon.

(i) *Unintentional reversals.* Requirements for unintentional reversals are as follows:

(a) The project sponsor must notify the REGULATORY AGENCY of the reversal and provide an explanation for the nature of the unintentional reversal within 30 calendar days of its discovery; and

(b) The project sponsor must submit to the REGULATORY AGENCY a verified estimate of current carbon stocks within the offset project boundary within one year of the discovery of the unintentional reversal.

(ii) *Intentional Reversals.* Requirements for intentional reversals are as follows:

(a) If an intentional reversal occurs, the project sponsor shall, within 30 calendar days of the intentional reversal:

(1) Provide notice, in writing, to the REGULATORY AGENCY of the intentional reversal; and

(2) Provide a written description and explanation of the intentional reversal to the REGULATORY AGENCY.

(b) Within one year of the occurrence of an intentional reversal, the project sponsor shall submit to the REGULATORY AGENCY a verified estimate of current carbon stocks within the offset project boundary.

(c) If an intentional reversal occurs, and CO_2 offset allowances have been awarded to the offset project, the forest owner

must surrender to the REGULATORY AGENCY or its agent for retirement a quantity of CO_2 allowances corresponding to the quantity of CO_2 equivalent tons reversed within six months of notification by the REGULATORY AGENCY.

(1) Notification by the REGULATORY AGENCY will occur after the verified estimate of carbon stocks has been submitted to the REGULATORY AGENCY, or after one year has elapsed since the occurrence of the reversal if the project sponsor fails to submit the verified estimate of carbon stocks.

(2) If the forest owner does not surrender valid CO_2 allowances to the REGULATORY AGENCY within six months of notification by the REGULATORY AGENCY, the forest owner will be subject to enforcement action and each CO_2 equivalent ton of carbon sequestration reversed will constitute a separate violation of this Part and applicable state law.

(d) *Project Termination.* Requirements for project termination are as follows:

(1) The project sponsor must surrender to the REGULATORY AGENCY or its agent for retirement a quantity of CO_2 Allowances in the amount calculated pursuant to project termination provisions in the forest offset protocol within six months of project termination.

(2) If the project sponsor does not surrender to the REGULATORY AGENCY or its agent a quantity of CO_2 Allowances in the amount calculated pursuant to project termination provisions in the forest offset

protocol within six months of project termination, they will be subject to enforcement action and each CO_2 offset allowance not surrendered will constitute a separate violation of this Part and applicable state law

(iii) *Disposition of Forest Sequestration Projects After a Reversal.* If a reversal lowers the forest offset project's actual standing live carbon stocks below its project baseline standing live carbon stocks, the forest offset project will be terminated by the REGULATORY AGENCY.

(9) *Timing of forest offset projects.* The REGULATORY AGENCY may award CO_2 offset allowances under section XX-10.7 only for forest offset projects that are initially commenced on or after January 1, 2014.

(10) *Projects that Have Been Awarded Credits by a Voluntary Greenhouse Gas Reduction Program*. The provisions of paragraphs XX-10.3(c)(4) and XX-10.4(b)(2) shall not apply to forest projects that have been awarded credits under a voluntary greenhouse gas reduction program provided that the following conditions are satisfied. For such projects, the number of CO_2 Offset Allowances will be calculated pursuant to the requirements of XX-10.5(b), without regard to quantity of credits that were awarded to the project under the voluntary program.

(i) The project satisfies all other general requirements of XX-10, including all specific requirements of XX-10.5(b), for all reporting periods for which the project has been awarded credits under a voluntary greenhouse gas program and also intends to be awarded CO_2 offset allowances pursuant to XX-10.7.

(ii) At the time of submittal of the consistency application for the project, the project submits forest offset data reports and a monitoring and verification report covering all reporting periods for which the project has been awarded credits under a voluntary greenhouse gas program and also intends to be awarded CO_2

offset allowances pursuant to XX-10.7. Forest offset data reports and monitoring and verification reports must meet all requirements of XX-10.5(b)(5) and (6).

(iii) The consistency application includes information sufficient to allow the Department to make the following determinations, and the voluntary greenhouse gas program has published information on its website to allow the Department to verify the information included in the consistency application.

(a) The offset project has met all legal and contractual requirements to allow it to terminate its relationship with the voluntary greenhouse gas program, and such termination has been completed.

(b) The project sponsor or voluntary greenhouse gas program has cancelled or retired all credits that were awarded for carbon sequestration that occurred during the time periods for which the project intends to be awarded CO_2 offset allowances pursuant to XX-10.7, and such credits were cancelled or required for the sole purpose of allowing the project to be awarded CO_2 offset allowances pursuant to XX-10.7.

(c) *Avoided methane emissions from agricultural manure management operations*. To qualify for the award of CO_2 offset allowances under XX-10, offset projects that capture and destroy methane from animal manure and organic food waste using anaerobic digesters shall meet the requirements of XX-10.5(c) and all other applicable requirements of XX-10.

(1) *Eligibility*.

(i) Eligible offset projects shall consist of the destruction of that portion of methane generated by an anaerobic digester that would have

been generated in the absence of the offset project through the uncontrolled anaerobic storage of manure or organic food waste.

(ii) Eligible offset projects shall employ only manure-based anaerobic digester systems using livestock manure as the majority of digester feedstock, defined as more than 50% of the mass input into the digester on an annual basis. Organic food waste used by an anaerobic digester shall only be that which would have been stored in anaerobic conditions in the absence of the offset project.

(iii) The provisions of paragraphs XX-10.3(c)(2) and (3) shall not apply to agricultural manure management offset projects provided either of the following requirements are met.

(a) The offset project is located in a state that has a market penetration rate for anaerobic digester projects of 5% or less. The market penetration determination shall utilize the most recent market data available at the time of submission of the consistency application pursuant to section XX-10.4 and shall be determined as follows:

$$MP\ (\%) = MG_{AD} / MG_{STATE}$$

Where:

MG_{AD} = Average annual manure generation for the number of dairy cows and swine serving all anaerobic digester projects in the applicable state at the time of submission of a consistency application pursuant to section XX-10.4.

MG_{STATE} = average annual manure production of all dairy cows and swine in the state at the time of submission of a consistency application pursuant to section XX-10.4.

(b) The offset project is located at a farm with 4,000 or less head of dairy cows, or a farm with equivalent animal units, assuming an average live weight for dairy cows (lbs./cow) of 1,400 lbs., or, if the project is a regional-type digester, total annual manure input to the digester is designed to be less than the average annual manure produced by a farm with 4,000 or less head of dairy cows, or a farm with equivalent animal units, assuming an average live weight for dairy cows (lbs./cow) of 1,400 lbs.

(2) *Offset project description.* The offset project sponsor shall provide a detailed narrative of the offset project actions to be taken, including documentation that the offset project meets the eligibility requirements of paragraph (1) of this subdivision. The offset project narrative shall include the following information:

(i) Owner and operator of the offset project;

(ii) Location and specifications of the facility where the offset project will occur;

(iii) Owner and operator of the facility where the offset project will occur;

(iv) Specifications of the equipment to be installed and a technical schematic of the offset project; and

(v) Location and specifications of the facilities from which anaerobic digester influent will be received, if different from the facility where the offset project will occur.

(3) *Emissions baseline determination.* The emissions baseline shall represent the potential emissions of the CH_4 that would have been produced in a baseline scenario under uncontrolled anaerobic storage conditions and released directly to the atmosphere in the absence of the offset project.

(i) Baseline CH_4 emissions shall be calculated as follows**:**

$$E_b = \frac{V_m \times M}{2000} \times GWP$$

Where:

E_b = Potential CO_2e emissions due to calculated CH_4 production under site-specific anaerobic storage and weather conditions (tons);

V_m = Volume of CH_4 produced each month from decomposition of volatile solids in a baseline uncontrolled anaerobic storage scenario under site-specific storage and weather conditions for the facility at which the manure or organic food waste is generated (ft^3);

M = Mass of CH_4 per cubic foot (0.04246 lb/ft^3 default value at one atmosphere and 20°C); and

GWP = Global warming potential of CH_4 (28).

(ii) The estimated amount of volatile solids decomposed each month under the uncontrolled anaerobic storage baseline scenario (kg) shall be calculated as follows:

$VS_{dec} = VS_{avail} \times f$

Where:

VS = volatile solids as determined from the equation:

$VS = M_m \times TS_{\%} \times VS_{\%}$

Where:

M_m = mass of manure or organic food waste produced per month (kg)

$TS_{\%}$ = concentration (percent) of total solids in manure or organic food waste as determined through EPA 160.3 testing method (U.S.EPA Method Number 160.3, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020));

$VS_{\%}$ = concentration (percent) of volatile solids in total solids as determined through EPA 160.4 testing method (U.S.EPA Method Number 160.4, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020)); and

VS_{avail} = volatile solids available for decomposition in manure or organic food waste storage each month as determined from the equation:

$$VS_{avail} = VS_p + \tfrac{1}{2} VS_{in} - VS_{out}$$

Where:

VS_p = volatile solids present in manure or organic food waste storage at beginning of month (left over from previous month) (kg);

VS_{in} = volatile solids added to manure or organic food waste storage during the course of the month (kg). The factor of ½ is multiplied by this number to represent the average mass of volatile solids available for decomposition for the entire duration of the month;

VS_{out} = volatile solids removed from the manure or organic food waste storage for land application or export (assumed value based on standard farm practice); and

f = van't Hoff-Arrhenius factor for the specific month as determined using the equation below. Using a base temperature of 30° C, the equation is as follows:

$$f = \exp\left[\frac{E(T_2 - T_1)}{GC \times T_1 \times T_2}\right]$$

Where:

f = conversion efficiency of VS to CH_4 per month;

E = activation energy constant (15,175 cal/mol);

T_2 = average monthly ambient temperature for facility where manure or organic food waste is generated (converted from ^{o} Celsius to ^{o} Kelvin) as determined from the nearest National Weather Service certified weather station (if reported temperature ^{o} C > 5^{o} C; if reported temperature ^{o}C < 5^{o} C, then f = 0.104);

T_1 = 303.15 (30^{o} C converted to ^{o}K); and

GC = ideal gas constant (1.987 cal/K mol)

(iii) The volume of CH_4 produced (ft^3) from decomposition of volatile solids shall be calculated as follows:

$V_m = (VS_{dec} \times B_o) \times 35.3147$

Where:

V_m = volume of CH_4 (ft^3)

VS_{dec} = volatile solids decomposed (kg)

B_o = manure or organic food waste type-specific maximum methane generation constant (m^3 CH_4/kg VS decomposed). For dairy cow manure, B_o = 0.24 m^3 CH_4/kg VS decomposed. The methane generation constant for other types of manure shall be those cited at U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010, Annex 3, Table A 180 (U.S. EPA, February 2017) , unless the project sponsor proposes an alternate methane generation constant and that alternate is approved by the REGULATORY AGENCY. If the project sponsor proposes to use a methane generation constant other than the ones found in the above-cited reference, the project sponsor must provide justification and documentation to the REGULATORY AGENCY.

(4) *Calculating emissions reductions.* Emissions reductions shall be calculated as follows:

$ER_t = E_b – E_p$

Where:

ER_t = CO_2e emissions reductions due to project activities (tons);

E_b = Potential CO_2e emissions due to calculated CH_4 production under site-specific anaerobic storage and weather conditions (tons);

E_p = CO_2e emissions due to project activities additional to baseline (tons), including, but not limited to, manure transportation, flaring, venting, and effluent management.

Emissions reductions may not exceed the potential emissions of the anaerobic digester, as represented by the annual volume of CH_4 produced by the anaerobic digester, as monitored pursuant to paragraph (5) of this

subdivision. CO_2 emissions due to transportation of manure and organic food waste from the site where the manure and organic food waste was generated to the anaerobic digester shall be subtracted from the emissions reduction calculated pursuant to subparagraphs (3)(i) through (iii) of this subdivision. Transport CO_2 emissions shall be determined through one of the following methods:

(i) Documentation of transport fuel use for all shipments of manure and organic food waste from off-site to the anaerobic digester during each reporting year and a log of transport miles for each shipment. Off-site is defined as a location that is not contiguous with the property where the anaerobic digester is located. CO_2 emissions shall be determined through the application of an emissions factor for the fuel type used. If this option is chosen, the following emissions factors shall be applied as appropriate.

(a) Diesel fuel: 22.912 lbs. CO_2/gallon.

(b) Gasoline: 19.878 lbs. CO_2/gallon.

(c) Other fuel: submitted emissions factor approved by the REGULATORY AGENCY.

(ii) Documentation of total tons of manure and organic food waste transported from off-site for input into the anaerobic digester during each reporting year, as monitored pursuant to subparagraph (5)(i) of this subdivision, and a log of transport miles and fuel type used for each shipment. CO_2 emissions shall be determined through the application of a ton-mile transport emission factor for the fuel type used. If this option is chosen, the following emissions factors shall be applied as appropriate for each ton of manure delivered, and multiplied by the number of miles transported.

(a) Diesel fuel: 0.131 lbs. CO_2 per ton-mile.

(b) Gasoline: 0.133 lbs. CO_2 per ton-mile.

(c) Other fuel: submitted emissions factor approved by the REGULATORY AGENCY.

(5) *Monitoring and verification requirements.* Offset projects shall employ a system that provides metering of biogas volumetric flow rate and determination of CH_4 concentration. Annual monitoring and verification reports shall include monthly biogas volumetric flow rate and CH_4 concentration determination. Monitoring and verification shall also meet the following requirements.

(i) If the offset project is a regional-type digester, manure and organic food waste from each distinct source supplying to the anaerobic digester shall be sampled monthly to determine the amount of volatile solids present. Any emissions reduction will be calculated according to mass of manure and organic food waste (kg) being digested and percentage of volatile solids present before digestion, consistent with the requirements at paragraph (3) and subparagraph (5)(iii) of this subdivision, and apportioned accordingly among sources. The project sponsor shall provide supporting material and receipts tracking the monthly receipt of manure and organic food waste (kg) used to supply the anaerobic digester from each supplier.

(ii) If the offset project includes the digestion of organic food waste eligible pursuant to subparagraph (1)(ii) of this subdivision, organic food waste shall be sampled monthly to determine the amount of volatile solids present before digestion, consistent with the requirements at paragraph (3) and subparagraph (5)(iii) of this subdivision, and apportioned accordingly.

(iii) The project sponsor shall submit a monitoring and verification plan as part of the consistency application that includes a quality assurance and quality control program associated with equipment used to determine biogas volumetric flow rate and CH_4 composition.

The monitoring and verification plan shall be specified in accordance with the applicable monitoring requirements listed in Table 8 below. The monitoring and verification plan shall also include provisions for ensuring that measuring and monitoring equipment is maintained, operated, and calibrated based on manufacturer's recommendations, as well as provisions for the retention of maintenance records for audit purposes. The monitoring and verification plan shall be certified by an independent verifier accredited pursuant to section XX-10.6.

Table 8. Monitoring requirements

Parameter	Measurement Unit	Frequency of Sampling	Sampling Method(s)
Influent flow (mass) into the digester	Kilograms (kg) per month (wet mass)	Monthly total into the digester	a) Recorded mass b) Digester influent pump flow c) Livestock population and application of American Society of Agricultural and Biological Engineers (ASABE) standard (ASAE D384.2, March 2005)
Influent total solids concentration (TS)	Percent (of sample)	Monthly, depending upon recorded variations	U.S. EPA Method Number 160.3, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020)

Parameter	Measurement Unit	Frequency of Sampling	Sampling Method(s)
Influent volatile solids (VS) concentration	Percent (of TS)	Monthly, depending upon recorded variations	USEPA Method Number 160.4, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020)
Average monthly ambient temperature	Temperature ^{o}C	Monthly (based on farm averages)	Closest National Weather Service-certified weather station
Volume of biogas produced by digester	Standard cubic feet (scf)	Continuous, totalized monthly	Flow meter
Methane composition of biogas produced by digester	Percent (of sample)	Quarterly	Bag sampling and third party laboratory analysis using applicable U.S. EPA test methods

XX-10.6 Accreditation of independent verifiers.

(a) *Standards for accreditation*. Independent verifiers may be accredited by the REGULATORY AGENCY to provide verification services as required of project sponsors under this Subpart, provided that independent verifiers meet all of the requirements of this section.

(1) *Verifier minimum requirements*. Each accredited independent verifier shall demonstrate knowledge of the following topics:

(i) Utilizing engineering principles;

(ii) Quantifying greenhouse gas emissions;

(iii) Developing and evaluating air emissions inventories;

(iv) Auditing and accounting principles;

(v) Knowledge of information management systems;

(vi) Knowledge of the requirements of this Subpart and other applicable requirements of this Part; and

(vii) Such other qualifications as may be required by the REGULATORY AGENCY to provide competent verification services as required for individual offset categories specified at section XX-10.5.

(2) *Organizational qualifications*. Accredited independent verifiers shall demonstrate that they meet the following requirements:

(i) Verifiers shall have no direct or indirect financial relationship, beyond a contract for provision of verification services, with any offset project developer or project sponsor;

(ii) Verifiers shall employ staff with professional licenses, knowledge, and experience appropriate to the specific category(ies) of offset projects at section XX-10.5 that they seek to verify.

(iii) Verifiers shall hold a minimum of one million U.S. dollars of professional liability insurance. If the insurance is in the name of a related entity, the verifier shall disclose the financial relationship between the verifier and the related entity, and provide documentation supporting the description of the relationship; and

(iv) Verifiers shall demonstrate that they have implemented an adequate management protocol to identify potential conflicts of interest with regard to an offset project, offset project developer, or project sponsor, or any other party with a direct or indirect financial interest in an offset project that is seeking or has been granted approval of a consistency application pursuant to subdivision XX-10.4(e), and remedy any such conflicts of interest prior to providing verification services.

(3) *Pre-qualification of verifiers*. The REGULATORY AGENCY may require prospective verifiers to successfully complete a training course, workshop, or test developed by the REGULATORY AGENCY or its agent, prior to submitting an application for accreditation.

(b) *Application for accreditation*. An application for accreditation shall not contain any proprietary information, and shall include the following:

(1) The applicant's name, address, e-mail address, telephone number, and facsimile transmission number;

(2) Documentation that the applicant has at least two years of experience in each of the knowledge areas specified at subparagraphs (a)(1)(i) through (v) of this section, and as may be required pursuant to subparagraph (a)(1)(vii) of this section;

(3) Documentation that the applicant has successfully completed the requirements at paragraph (a)(3) of this section, as applicable;

(4) A sample of at least one work product that provides supporting evidence that the applicant meets the requirements at paragraphs (a)(1) and (2) of this section. The work product shall have been produced, in whole or part, by the applicant and shall consist of a final report or other material provided to a client under contract in previous work. For a work product that was jointly produced by the applicant and another entity, the role of the applicant in the work product shall be clearly explained;

(5) Documentation that the applicant holds professional liability insurance as required pursuant to subparagraph (a)(2)(iii) of this section; and

(6) Documentation that the applicant has implemented an adequate management protocol to address and remedy any conflict of interest issues that may arise, as required pursuant to subparagraph (a)(2)(iv) of this section.

(c) *REGULATORY AGENCY action on applications for accreditation*. The REGULATORY AGENCY shall approve or deny a complete application for accreditation within 45 days after submission. Upon approval of an application for accreditation, the independent verifier shall be accredited for a period of three years from the date of application approval.

(d) *Reciprocity*. Independent verifiers accredited in other participating states may be deemed to be accredited in **[INSERT NAME OF RGGI STATE]**, at the discretion of the REGULATORY AGENCY.

(e) *Conduct of accredited verifiers.*

(1) Prior to engaging in verification services for an offset project sponsor, the accredited verifier shall disclose all relevant information to the REGULATORY AGENCY to allow for an evaluation of potential conflict of interest with respect to an offset project, offset project developer, or project sponsor. The accredited verifier shall disclose information concerning its ownership, past and current clients, related entities, as well as any other facts or circumstances that have the potential to create a conflict of interest.

(2) Accredited verifiers shall have an ongoing obligation to disclose to the REGULATORY AGENCY any facts or circumstances that may give rise to a conflict of interest with respect to an offset project, offset project developer, or project sponsor.

(3) The REGULATORY AGENCY may reject a verification report and certification statement from an accredited verifier, submitted as part of a consistency application required pursuant to subdivision XX-10.4(b) or submitted as part of a monitoring and verification report submitted pursuant to subdivision XX-10.7(b), if the REGULATORY AGENCY determines that the accredited verifier has a conflict of interest related to the offset project, offset project developer, or project sponsor.

(4) The REGULATORY AGENCY may revoke the accreditation of a verifier at any time given cause, for the following:

(i) Failure to fully disclose any issues that may lead to a conflict of interest situation with respect to an offset project, offset project developer, or project sponsor;

(ii) The verifier is no longer qualified due to changes in staffing or other criteria;

(iii) Negligence or neglect of responsibilities pursuant to the requirements of this Subpart; and

(iv) Intentional misrepresentation of data or other intentional fraud.

XX-10.7 Award and Recordation of CO_2 offset allowances.

(a) *Quantities of CO_2 offset allowances awarded, and subsequently recorded*.

(1) *Award of CO_2 offset allowances*.

(i) *CO_2 emissions offset projects*. Following the issuance of a consistency determination under paragraph XX-10.4(e)(2) and the approval of a monitoring and verification report under the provisions of subdivision (e) of this section, the REGULATORY AGENCY will award one CO_2 offset allowance for each ton of demonstrated reduction in CO_2 or CO_2 equivalent emissions or sequestration of CO_2.

(2) *Recordation of CO_2 offset allowances*. After CO_2 offset allowances are awarded under XX-10.7(a)(1), the **[REGULATORY AGENCY]** shall record such CO_2 offset allowances in the project sponsor's general account.

(b) *Deadlines for submittal of monitoring and verification reports.*

(1) For CO_2 emissions offset projects undertaken prior to January 1, 2009, the project sponsor must submit the monitoring and verification report covering the pre-2009 period by June 30, 2009.

(2) For CO_2 emissions offset projects undertaken on or after January 1, 2009, the monitoring and verification report must be submitted within 6 months following the completion of the last calendar year during which the offset project achieved CO_2 equivalent reductions or sequestration of CO_2 for which the project sponsor seeks the award of CO_2 offset allowances.

(c) *Contents of monitoring and verification reports.* For an offset project, the monitoring and verification report must include the following information.

(1) The project's sponsor's name, address, e-mail address, telephone number, facsimile transmission number, and account number;

(2) The CO_2 emissions reduction or CO_2 sequestration determination as required by the relevant provisions of section XX-10.5, including a demonstration that the project sponsor complied with the required quantification, monitoring, and verification procedures under section XX-10.5, as well as those outlined in the consistency application approved pursuant to paragraph XX-10.4(e)(2).

(3) A signed statement that reads "The undersigned project sponsor hereby confirms and attests that the offset project upon which this monitoring and verification report is based is in full compliance with all of the requirements of Subpart XX-10. The project sponsor holds the legal rights to the offset project, or has been granted the right to act on behalf of a party that holds the legal rights to the offset project. I understand that eligibility for the award of CO_2 offset allowances under Subpart XX-10 is contingent on meeting the requirements of Subpart XX-10. I authorize the REGULATORY AGENCY or its agent to audit this offset project for purposes of verifying that the offset project, including the monitoring and verification plan, has been implemented as described in the consistency application that was the subject of a consistency determination by the REGULATORY AGENCY. I understand that this right to audit shall include the right to enter the physical location of the offset project and to make available to the REGULATORY AGENCY or its agent any and all documentation relating to the offset project at the REGULATORY AGENCY's request. I submit to the legal jurisdiction of **[RGGI PARTICIPATING STATE]**."

(4) A certification signed by the offset project sponsor certifying that all offset projects for which the sponsor has received offset allowances under this

Subpart (or similar provisions in the rules of other participating states), under the sponsor's ownership or control (or under the ownership or control of any entity which controls, is controlled by, or has common control with the sponsor) are in compliance with all applicable requirements of the CO_2 Budget Trading Program in all participating states.

(5) A verification report and certification statement signed by an independent verifier accredited pursuant to section XX-10.6 that documents that the independent verifier has reviewed the monitoring and verification report and evaluated the following in relation to the applicable requirements at section XX-10.5, and any applicable guidance issued by the REGULATORY AGENCY.

(i) The adequacy and validity of information supplied by the project sponsor to determine CO_2 emissions reductions or CO_2 sequestration pursuant to the applicable requirements at section XX-10.5.

(ii) The adequacy and consistency of methods used to quantify, monitor, and verify CO_2 emissions reductions and CO_2 sequestration in accordance with the applicable requirements at section XX-10.5 and as outlined in the consistency application approved pursuant to paragraph XX-10.4(e)(2).

(iii) Such other evaluations and verification reviews as may be required by the REGULATORY AGENCY. The adequacy and validity of information supplied by the project sponsor to demonstrate that the offset project meets the applicable eligibility requirements of section XX-10.5.

(6) Disclosure of any voluntary or mandatory programs, other than the CO_2 Budget Trading Program, to which greenhouse gas emissions data related to the offset project has been, or will be reported.

(7) For offset projects located in a state or United States jurisdiction that is not a participating state, a demonstration that the project sponsor has complied with all requirements of the cooperating regulatory agency in the state or United States jurisdiction where the offset project is located.

(d) *Prohibition against filing monitoring and verification reports in more than one participating state*. Monitoring and verification reports may only be filed under XX-10.7 for projects that have received consistency determinations under XX-10.4(e)(2) Monitoring and verification reports may not be filed under XX-10.7 for projects that have received consistency determinations in other participating states.

(e) *REGULATORY AGENCY action on monitoring and verification reports*. The REGULATORY AGENCY will approve or deny a complete monitoring and verification report, in a format approved by the REGULATORY AGENCY, filed with the REGULATORY AGENCY pursuant to XX-10.7(d), within 45 days following receipt of a complete report. A complete monitoring and verification report is one that is in an approved form and is determined by the REGULATORY AGENCY to be complete for the purpose of commencing review of the monitoring and verification report. In no event shall a completeness determination prevent the REGULATORY AGENCY from requesting additional information in order to enable the REGULATORY AGENCY to approve or deny a monitoring and verification report submitted in a format approved by the REGULATORY AGENCY, and filed under XX-10.7.

Attachment 35

The Regional Greenhouse Gas Initiative
an initiative of Eastern States of the US

About the Regional Greenhouse Gas Initiative

The **Regional Greenhouse Gas Initiative (RGGI)** is a cooperative effort among eleven Eastern states to reduce carbon dioxide (CO_2) emissions from power plants within each participating state.

Together, the participating states have established a **regional cap** on CO_2 emissions, which sets a limit on the emissions from regulated power plants within the RGGI states. Over time, the regional cap declines, so that CO_2 emissions decrease in a planned and predictable way. Since its inception, RGGI emissions have reduced by more than 50%—twice as fast as the nation as a whole—and raised over $4 billion to invest into local communities.

Who are the RGGI states? *The participating RGGI states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia.*

How Does RGGI Work?

RGGI is a market-based cap-and-invest initiative. Within the RGGI states, regulated power plants must acquire one **RGGI CO_2 allowance** for every short ton of CO_2 they emit. The RGGI states distribute allowances at quarterly auctions, where they can be purchased by power plants and other entities. Some states hold a limited number of allowances in set-aside accounts to sell at a fixed price or otherwise distribute outside of the auction process.

Each participating state originates allowances in proportion to its share of the regional cap. To comply with their state's regulations, power plants sized 25 megawatts[1] or greater must acquire enough RGGI allowances to cover their emissions. See **Tracking and Compliance** on page 2 for more details.

Happening Now: Third Program Review

The RGGI states work together to develop a Model Rule, which acts as a template for each state to shape its own **CO_2 budget trading program**. Once a state has implemented its program it is able to participate in RGGI auctions and access other shared aspects of this regional effort.

The RGGI states periodically conduct **Program Review** to examine the successes, impacts, and design of their CO_2 budget trading programs, and to consider updates to the Model Rule and their individual state programs. During the first two Program Reviews, the states implemented changes that improved program design and reduced the regional emissions cap. In September 2021, the states launched the Third Program Review, which will include opportunities for public engagement. For more information, visit the Program Review page of the RGGI website.

Photo courtesy of the Rhode Island Office of Energy Resources

Investing in a Clean and Equitable Future

*The RGGI states receive the proceeds from selling RGGI allowances, and each state has discretion over how to best use their proceeds. Most of the proceeds have been invested by states back into their communities, including funding of clean energy programs, energy efficiency, and bill assistance to local businesses and communities. Investments targeting low-income households have increased over time and reached 16% of total proceeds in 2019. View the **Investment of RGGI Proceeds** page of the RGGI website to see the latest report on how RGGI proceeds are supporting a clean energy future across the region.*

[1] In New York, power plants sized 15 megawatts or greater are regulated under RGGI.

About RGGI Auctions and Allowance Tracking

Auctions are the primary method by which the RGGI states distribute CO_2 allowances. Auctioning allowances ensures all parties have access to allowances under uniform terms, helps establish a market-based value for the price of CO_2 allowances, avoids windfall profits for power plant owners, and supports investments in a clean and equitable future. The RGGI states have established multiple ways to enhance market stability, described in **Auction Mechanisms** below. An independent market monitor provides oversight of the auctions, as well as activity on the secondary market, to ensure integrity of, and confidence in, the market. You can learn more and view the Market Monitor reports here.

Auction Mechanisms

The RGGI auction mechanisms are designed to provide some measure of stability to the market. The **Minimum Reserve Price** is the minimum price that allowances can be sold for at a RGGI auction. In 2021, the reserve price is $2.38 per allowance.

The **Cost Containment Reserve (CCR)** and **Emissions Containment Reserve (ECR)** are reserves of allowances that help provide market stability if the cost of reducing emissions is higher or lower than expected. CCR allowances are made available for sale at an auction if the allowance price would otherwise exceed a set trigger price. Conversely, ECR allowances are withheld from sale at an auction, if the price would otherwise fall below a set trigger price. In 2021, the CCR trigger price is $13.00 and the ECR trigger price is $6.00. For more information about auction mechanisms, visit the Elements of RGGI page of the RGGI website.

Setting the Auction Clearing Price

All the allowances sold at any one auction are sold at the same price. The price for an allowance is set at the value where demand for allowances equals the available supply.

To find this price, available allowances are awarded to bidders based on bid price from high to low until no allowances remain. The price of the lowest bid to be matched to an allowance becomes the ***auction clearing price*** *and is the value at which all allowances are sold for that auction. View the* ***Auction Tutorial*** *for more details about auction price setting.*

Tracking & Compliance

The acquisition, transfer, retirement, and surrender of RGGI CO_2 allowances is tracked on the RGGI CO_2 Allowance Tracking System (RGGI COATS) platform. Any individual who successfully sets up a RGGI COATS login and creates a RGGI COATS account can receive, transfer, and hold RGGI allowances within the RGGI COATS platform.

Every year, regulated power plants must surrender allowances equal to one half of their CO_2 emissions for that year. Every three years, called a **control period**, they must surrender allowances for all emissions from year three, plus all remaining emissions from years one and two. The three-year control period provides power plants flexibility for meeting the program requirements. More information on compliance is available in the Compliance section of the RGGI website.

Offset Allowances

Certain projects that reduce CO_2 and other greenhouse gas emissions outside of RGGI regulations may be eligible for awards of RGGI **CO_2 offset allowances**. To be eligible for offset allowances, a project must be located within one of the RGGI states and fall into one of the offset project categories accepted by that state. These project categories, and which states accept each category, can be found in the Offsets section of the RGGI website. Offset allowances are transferable and may be used by regulated power plants to meet up to 3.3% of compliance obligations. CO_2 offset allowances account for less than 0.01% of the total number of allowances issued by the program since its inception in 2009.

To learn more about RGGI, please visit the RGGI website or send a message to info@rggi.org.

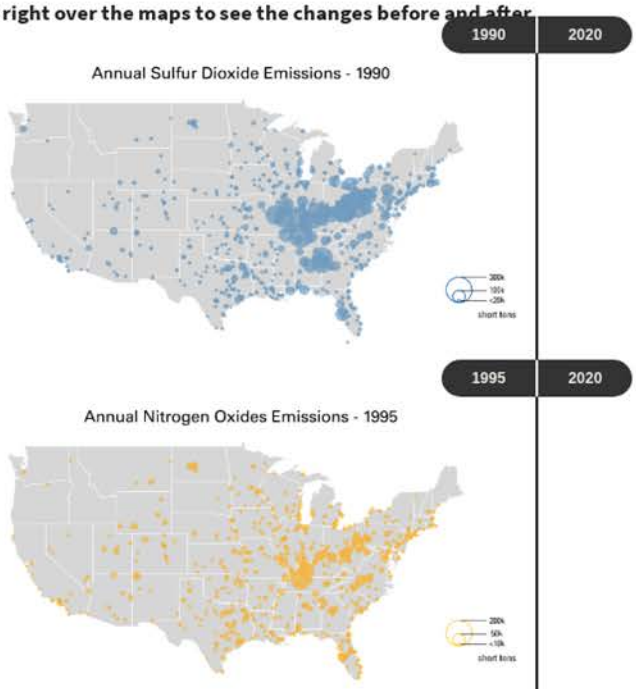
Attachment 36

An official website of the United States government.

Acid Rain Program Results

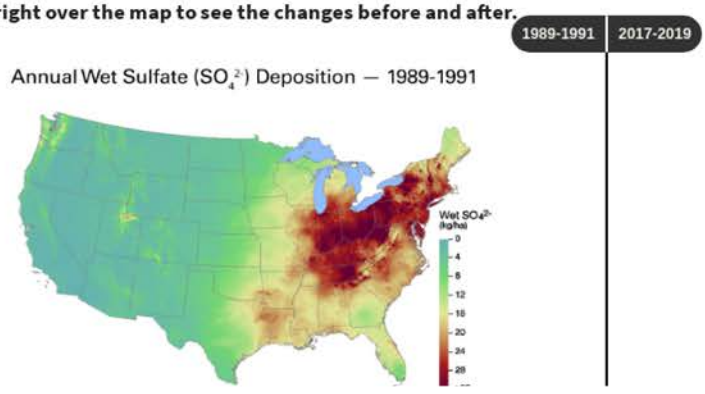
The Acid Rain Program (ARP) has delivered significant reductions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions from fossil fuel-fired power plants, extensive environmental and human health benefits, and far lower-than-expected costs. Together with more recent power sector regulations, including the Cross-State Air Pollution Rule (CSAPR), and a rapidly changing energy sector, the ARP has helped deliver annual SO_2 reductions of over 93% and annual NO_X emissions reductions of over 87%. The Power Plant Emissions Trends page has maps and data highlighting these emissions reductions, and the Progress Reports provide an annual overview of program features and results, from compliance to air quality impacts.

Hover left to right over the maps to see the changes before and after.



These emissions reductions have led to major decreases in acid rain nationwide. Wet sulfate deposition – a common indicator of acid rain – dropped by 68% between 1989-1991 and 2017-2019. Additional data and maps detailing deposition and ambient air pollution are available on the Clean Air Status and Trends Network (CASTNET) website.

Hover left to right over the map to see the changes before and after.



The Long Term Monitoring program (LTM), another monitoring program within EPA, observes surface waters to determine the effects of acid rain on aquatic ecosystems. During the time period in which wet sulfate deposition decreased, LTM data show an 81% improvement in the number of monitored streams and lakes that experienced critical load exceedances, an indicator that reveals when acid deposition levels are causing harmful effects. The goal of this long-term program is to track whether the Clean Air Act Amendments (Plain English Guide to the Clean Air Act) have been effective in reducing the acidity of surface waters.

Next, learn more about the details of the Acid Rain Program.

Or, learn more about:

- Acid Rain
- Clean Air Markets
- Clean Air Status and Trends Network (CASTNET)
- National Atmospheric Deposition Program (NADP) EXIT
- Long-Term Monitoring (LTM) Network

Contact Us to ask a question, provide feedback, or report a problem.

// image slider

Attachment 37

Regional Greenhouse Gas Initiative
an Initiative of the Northeast and Mid-Atlantic States of the U.S.

Summary of RGGI Model Rule Updates
December 19, 2017

The Regional Greenhouse Gas Initiative (RGGI) is composed of individual CO_2 Budget Trading Programs in each RGGI participating state. Each participating state's CO_2 Budget Trading Program is based on the RGGI Updated Model Rule (2013), which was developed to provide guidance to states as they implemented the RGGI program. RGGI participating states have been conducting a Program Review, which is a comprehensive evaluation of program successes, program impacts, the potential for additional reductions, imports and emissions leakage, and offsets.

Proposed amendments to the Model Rule were developed by the RGGI state staff as part of the Program Review. This effort was supported by an extensive regional stakeholder process that engaged the regulated community, environmental non-profits, and other organizations with technical expertise in the design of cap-and-trade programs.

A summary of the proposed amendments to the RGGI Program, as detailed in the Model Rule, are discussed below.

Size and Structure of Cap and Allowance Apportionment (XX-5.1)

The regional emissions cap in 2021 will be equal to 75,147,784 tons and will decline by 2.275 million tons of CO_2 per year thereafter, resulting in a total 30% reduction in the regional cap from 2020 to 2030.

Budget Adjustments (XX-5.3)

The Model Rule contains language to address the private bank of allowances through one additional, distinct budget adjustment.

- The Third Adjustment for Banked Allowances, would adjust the base budget for 100 percent of the pre-2021 vintage allowances held by market participants as of the end of 2020, that are in excess of the total quantity of 2018, 2019, and 2020 emissions. The third adjustment timing and algorithm is spelled out in the Model Rule and would be implemented over the 5-year period, 2021-2025, after the actual size of the 2020 vintage private bank is determined.

Cost Containment Reserve (XX-5.3(d) and XX-9)

The Model Rule contains language for the continued use of a cost containment reserve (CCR) that will provide flexibility and cost containment for the program. The CCR would consist of a

fixed quantity of allowances, in addition to the cap, that would be held in reserve, and only made available for sale if allowance prices exceed predefined price levels.

- The Model Rule contains language for an annual CCR allowance quantity of 10% of the regional cap beginning in 2021 and each succeeding year thereafter.
- Allowances from the CCR would be fully fungible.
- The CCR allowances would be made available immediately in any auction in which demand for allowances at prices above the CCR trigger price exceeds the supply of allowances offered for sale in that auction prior to the addition of any CCR allowances.
- If the CCR is triggered, the CCR allowances would only be sold at or above the CCR trigger price.
- The CCR Trigger Price will be $13.00 in 2021 and rise at 7% per year, so that the CCR will only trigger if emission reduction costs are higher than projected.

Emissions Containment Reserve (XX-5.3(e) and XX-9)

The Model Rule contains language for the creation and use of an emissions containment reserve (ECR) that will respond to supply and demand in the market if emission reduction costs are lower than projected. States will withhold allowances from circulation to secure additional emissions reductions if prices fall below established trigger prices. At this time, Maine and New Hampshire do not intend to implement an ECR. Allowances withheld in this way will not be reoffered for sale.

- The Model Rule contains language for an annual ECR allowance withholding limit of 10% of the budgets of states implementing the ECR.
- The ECR trigger price will be $6.00 in 2021, and rise at 7% per year, so that the ECR will only trigger if emission reduction costs are lower than projected.

Offsets (XX-10.2 and XX-10.5)

The Model Rule contains language that eliminates two offset categories, the "SF_6 Offset Category (XX-10.5(b))" and the "End-Use Energy Efficiency Offsets Category (XX-10.5(d))," and updates and retains three categories that some States may continue to implement. Any awarded offset allowances would remain fully fungible across the states.

Miscellaneous

Reserve Price (XX-1.2)

The Model Rule retains language to increase the minimum reserve price by 2.5 percent each year.

Attachment 38

The Regional Greenhouse Gas Initiative

An Initiative of Eastern States of the United States

The Investment of RGGI Proceeds in 2020

Published May 2022

www.rggi.org

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This report is the product of the Regional Greenhouse Gas Initiative, Inc. (RGGI, Inc.). For regulatory matters, consult the regulations of each state cited throughout this report. RGGI, Inc. is a 501(c)(3) non-profit corporation formed to provide technical and administrative services to the RGGI CO_2 Budget Trading Programs of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia.

Executive Summary

Proceeds from the Regional Greenhouse Gas Initiative (RGGI) have powered significant investment in the energy future of participating Eastern states. This report reviews the benefits of programs funded in 2020 by $196 million in RGGI investments, which have reduced harmful carbon dioxide (CO_2) emissions while spurring local economic growth. The lifetime effects of 2020 RGGI investments are projected to avoid the release of 6.6 million short tons of carbon emissions. RGGI-funded programs also save consumers and businesses money, create jobs, and provide targeted assistance to low-income communities throughout the RGGI region. RGGI investments in 2020 are estimated to return $1.9 billion in lifetime energy bill savings to 65,000 households and 800 businesses that participated in programs funded by RGGI proceeds, while over 720,000 households and 38,000 businesses received direct bill assistance in 2020. As a whole, the RGGI states have reduced power sector CO_2 emissions over 50% since 2008, while the region's gross domestic product has continued to grow.

The benefits tracked in this report arise from RGGI investments in energy efficiency, clean and renewable energy, beneficial electrification, direct bill assistance, and greenhouse gas abatement. Any benefits associated with other funds (such as transfers to general funds) are outside the scope of this report.

RGGI states have individual discretion as to how they invest proceeds. Investments fall into five major categories:

Energy efficiency makes up 35% of 2020 RGGI investments and 53% of cumulative investments. Programs funded by these investments in 2020 are expected to return about $1.2 billion in lifetime energy bill savings to more than 56,000 participating households and over 700 businesses in the region and avoid the release of 4.6 million short tons of CO_2.

Clean and renewable energy makes up 18% of 2020 RGGI investments and 14% of cumulative investments. RGGI investments in these technologies in 2020 are expected to return over $600 million in lifetime energy bill savings and avoid the release of more than 1.7 million short tons of CO_2.

Beneficial electrification makes up 11% of 2020 RGGI investments and 3% of cumulative investments. RGGI investments in beneficial electrification in 2020 are expected to avoid the release of 177,000 short tons of CO_2 and return nearly $90 million in lifetime savings.

Greenhouse gas abatement makes up 5% of 2020 RGGI investments and 8% of cumulative investments. RGGI investments in greenhouse gas (GHG) abatement in 2020 are expected to avoid the release of more than 160,000 short tons of CO_2 and to return over $51 million in lifetime savings.

Direct bill assistance makes up 19% of 2020 RGGI investments and 16% of cumulative investments. Direct bill assistance programs funded through RGGI in 2020 have returned over $37 million in credits or assistance to consumers.

This is the first version of this report which includes beneficial electrification as its own investment category. In previous versions of this report, investments in beneficial electrification programs were included within the other major investment categories.

These investments, in concert with the broader energy policies in each RGGI state, have enabled the region to continue to set a national example in driving decarbonization while strengthening economic resilience.

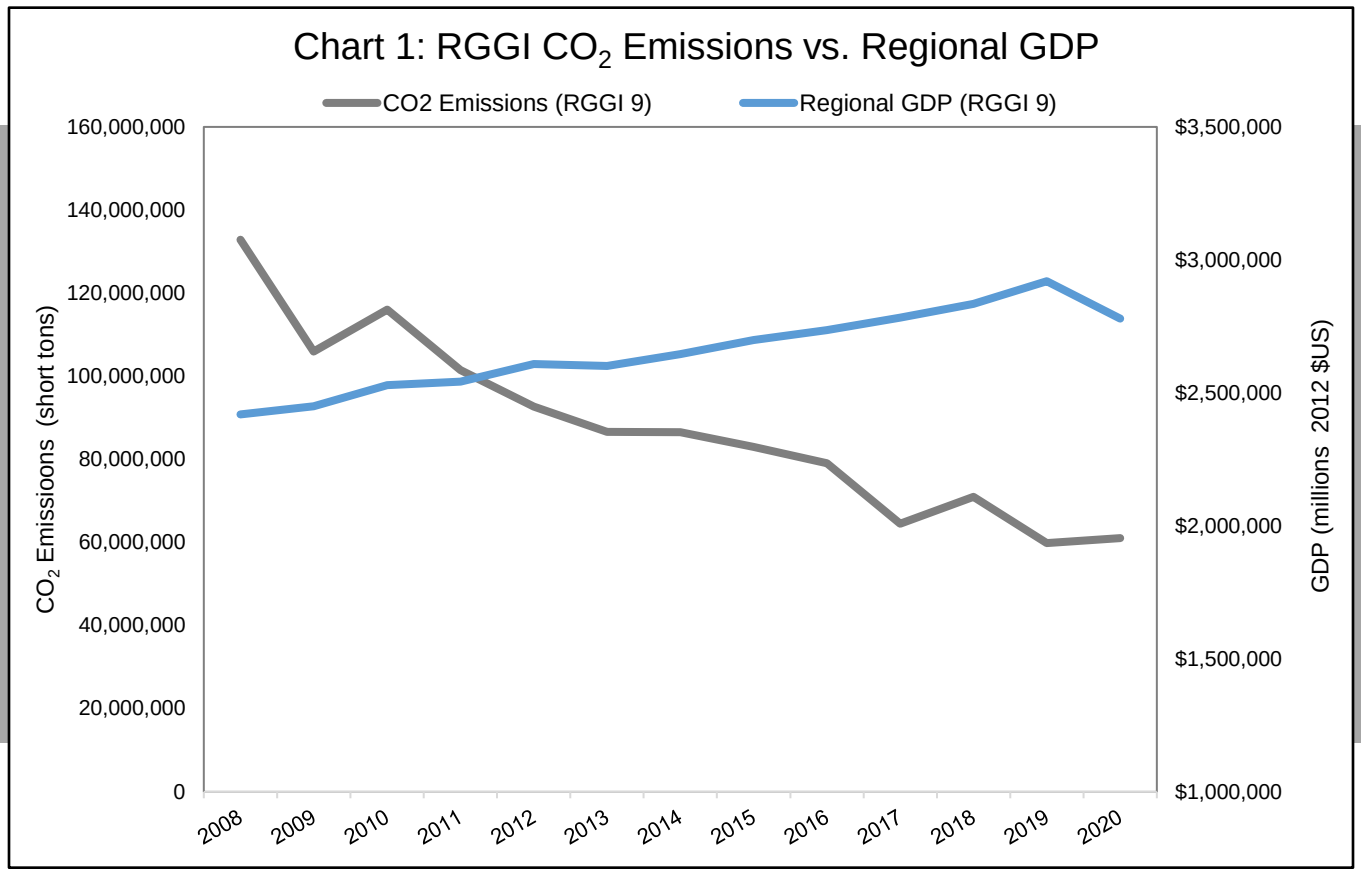
Introduction

The Regional Greenhouse Gas Initiative

RGGI is the nation's first multi-state initiative to reduce power sector CO_2 emissions. The RGGI states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia) establish a regional cap on the amount of CO_2 emissions that power plants can emit by issuing a limited number of tradable CO_2 allowances. Each allowance represents an authorization for a regulated power plant to emit one short ton of CO_2. Individual CO_2 budget trading programs in each RGGI state together create a regional market for CO_2 allowances. This allows market forces to determine the most cost-effective means of reducing emissions, and creates market certainty to drive long-term investments in clean energy. Each state's independent regulations are based on the RGGI Model Rule. New Jersey participated in RGGI from 2009 to 2011, and resumed its participation starting in 2020. RGGI investments in this report include the ten participating RGGI states in 2020.

The RGGI states have distributed 90% of CO_2 allowances through quarterly regional auctions, generating proceeds for reinvestment. The remaining allowances are allocated to state set-aside accounts, from which allowances may be distributed according to state-specific regulations or auctioned in future years. Each RGGI state has full discretion over the investment of RGGI proceeds and the administration of RGGI-funded programs.

The nine RGGI states that participated from 2009-2020 experienced a reduction of over 90 million short tons of annual power sector carbon emissions, even as the regional economy grew (see **Chart 1**).[1] This represents a reduction in power sector carbon emissions of over 50%.



[1] The nine RGGI states that participated for the entire 2009-2020 time period are CT, DE, ME, MD, MA, NH, NY, RI, and VT. The reduction in regional GDP in 2020 coincides with the onset of the COVID-19 pandemic.

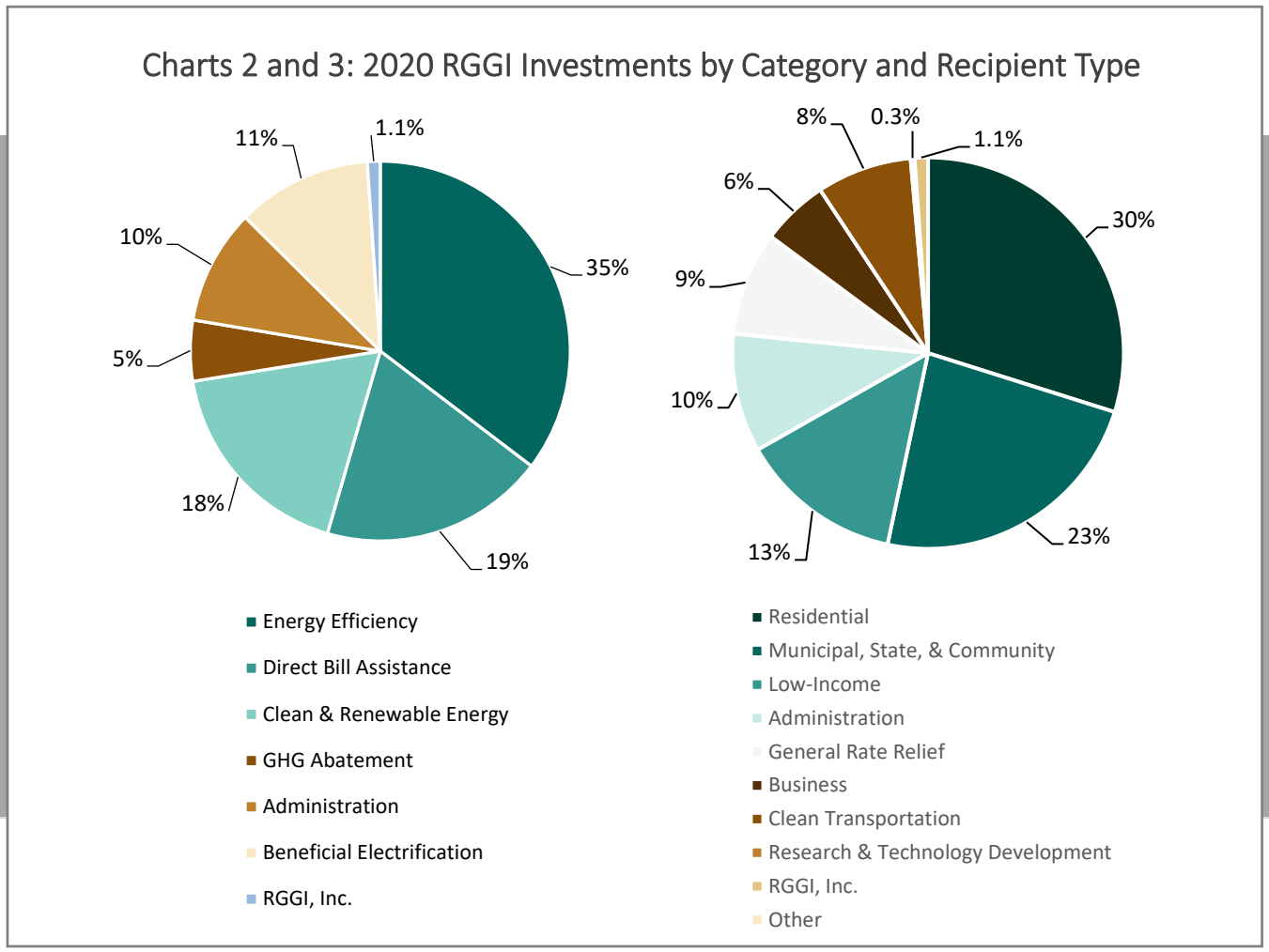
2020 RGGI Investments

This report estimates the benefits, such as energy bill savings and avoided CO_2 emissions, that arise from $196 million in 2020 RGGI investments. RGGI investments as defined within this report include investments in energy efficiency, clean and renewable energy, beneficial electrification, greenhouse gas abatement, and direct bill assistance, as well as administrative costs associated with these programs. This is the first version of this report which includes beneficial electrification as a separate category for the investment of proceeds. In previous reports, investments into beneficial electrification programs were included within the other major investment categories. This report focuses on 2020 annual investments. RGGI investments throughout the region cover a wide variety of programs.

Chart 2 shows 2020 RGGI investments divided among major program categories. **Chart 3** illustrates the same 2020 funds divided according to the type of end-user who benefits from the program or ultimately receives funding.

Many of the categories in Chart 3 can be seen as subcategories of those in Chart 2. Direct Bill Assistance is split between assistance for low-income consumers, and general rate relief for all consumers. GHG Abatement includes a wide variety of program types, including research funding and clean transportation programs. The Energy Efficiency and Clean Energy program categories mainly flow to residential, business, and municipal, state, & community recipients, with a substantial number of programs specifically serving low-income households.

Due to rounding, pie charts may not sum to exactly 100%.



In 2020, RGGI investments have saved participants money on their energy bills, created jobs, and reduced carbon emissions. Over their lifetime they will save participants an estimated $2 billion on energy bills, and avoid the emission of 6.7 million short tons of harmful CO_2 emissions. For details see **Table 1**.

RGGI investments benefit more than just those who directly participate in RGGI-funded programs. for example, money not spent on energy by families and businesses can be used in other ways that boost the economy. Reduced demand for energy also keeps power prices lower for everyone, and avoids investments in costly infrastructure to meet peak demand.

RGGI states have long been and continue to be leaders in energy efficiency, with millions of MWh saved. As the region's generation becomes cleaner, many states are also investing in beneficial electrification programs, which reduce carbon emissions by replacing direct fossil fuel use with electric power. Often, these programs result in an increases in MWh, but do reduce carbon emissions overall. As the grid becomes cleaner, the emissions from electrified appliances become cleaner, as opposed to the fixed emissions intensity of fossil-powered appliances.

Avoided MWh continues to be a relevant metric for energy efficiency and clean and renewable energy programs, and will be reported in the tables associated with these respective investment categories.

Table 1: Benefits of 2020 RGGI Investments

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments
Short Tons CO_2 Avoided	399,493	6,665,490
Energy Bill Savings	$143,819,935	$1,957,732,399

One of RGGI's strengths is the discretion held by each state to invest RGGI auction proceeds according to state-specific goals. This can present challenges for data collection; for example, a program offering discounts on efficient lightbulbs will collect quite different data from a program helping businesses to install large-scale equipment, or funding the installation of electric car charging stations. The data in this report are compiled using the output of state-based and program-based estimates for actual and projected savings and benefits. Methods for estimating program benefits differ across states and across programs. The appendix at the end of this report contains more details on how each metric is estimated for different types of programs.

States may also combine RGGI funds with funds from other sources. In many cases, the reported benefits from the program are adjusted based on the percentage of the program's funding that comes from RGGI. In cases where states determine a program could not have gone forward without RGGI funds, states will report the full benefits associated with that program.

Energy Efficiency

Energy efficiency remains the largest portion of 2020 RGGI investments, at 35%. Over the lifetime of the installed measures, 2020 RGGI investments in energy efficiency are projected to save participants nearly $1.2 billion on energy bills, providing benefits to more than 56,000 participating households and over 700 participating businesses. They are also projected to avoid the release of 4.6 million short tons of CO_2 (see **Table 2**).

Table 2: Benefits of 2020 RGGI Investments in Energy Efficiency

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments
Participating Households	56,412	n/a
Participating Businesses	737	n/a
Increased Employment	n/a	1400-1500*
Short Tons CO_2 Avoided	275,304	4,591,753
Energy Bill Savings	66,037,494	1,178,557,556
MMBtu Saved	1,869,047	31,427,411
MWh Saved	597,736	3,420,325

*Estimated job-years created.

Energy efficiency improvements can be achieved cost-effectively by upgrading appliances and lighting, weatherizing and insulating buildings, upgrading HVAC at offices, and improving industrial processes. For example, occupancy sensors automatically turn lights off when a room or building is not in use, saving significant amounts of energy. These programs allow consumers and businesses to take full advantage of modern appliances, heating, and cooling, increasing the comfort of homes, offices, and businesses while using less energy and saving on their energy bills.

Energy efficiency also creates jobs. Programs such as home retrofits directly spur employment gains in housing and construction, with 2020 RGGI investments projected to create an estimated additional 1400-1500 job-years across participating states. Lower energy costs also create numerous benefits across the economy, allowing businesses to expand and families to save and invest in other priorities.

Ultimately, all electricity consumers, not only those who make upgrades, benefit from energy efficiency programs. Lower overall demand for electricity results in lower wholesale electricity rates, as power plants with the highest costs do not run as often, and expensive transmission upgrades can be deferred in some cases. The full economy-wide benefits of energy efficiency are not modeled in this report. However, a range of other independent reports

have affirmed these widespread benefits of energy efficiency, including work by the Analysis Group, the Regulatory Assistance Project, and others.

RGGI-funded investments in energy efficiency, in concert with the broader energy policies in each RGGI state, have made the region a leader in this field. Six RGGI states once again ranked among 2020's top ten states for energy efficiency, according to the American Council for an Energy Efficient Economy.

Clean and Renewable Energy

Clean and renewable energy represents 18% of 2020 RGGI investments in the region. Over the lifetime of the projects installed in 2020, these investments are projected to offset $602 million in energy expenses. They are also projected to avoid the release of over 1.7 million short tons of CO_2 emissions (see **Table 3**).

Table 3: Benefits of 2020 RGGI Investments in Clean Energy

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments
Short Tons CO_2 Avoided	96,092	1,735,768
MWh Avoided*	192,903	3,473,936
MMBtu Avoided	25,965	576,144
Energy Bill Savings	$31,394,795	$601,955,014

*RGGI investments in clean and renewable energy decrease the electricity generated from marginal generating units, which are typically more expensive and carbon-intensive.

Clean energy systems require labor to install, which creates jobs and boosts local economic activity. Energy expenditures that might otherwise flow to out-of-state fossil fuel resources stay within the region. As with energy efficiency, “behind-the-meter” programs also contribute to lowering wholesale electricity prices by lowering the demand for electricity at the wholesale level. As demand for electricity decreases, the most expensive power plants run less often, driving long-term prices down for all consumers. Households and businesses both with and without clean energy systems save money on bills.

While RGGI investments are just a small part of widespread clean and renewable energy investments in the region, together these actions are having a measurable impact on the energy mix. Since 2008, RGGI states have increased their non-hydro renewable generation by 73%. In 2020 the RGGI states derived 50% of total generation from clean or renewable sources.

Beneficial Electrification

Beneficial electrification refers to programs that reduce carbon emissions by displacing direct fossil fuel use with electric power. In contrast to energy efficiency programs, which reduce electricity or fuels usage, beneficial electrification programs can increase MWh consumption, but result in a net reduction in carbon emissions. Examples include programs that promote the use of electric vehicles, reducing oil consumption, or the installation of electric heat pumps, reducing heating fuel and natural gas consumption.

Beneficial electrification represents 11% of 2020 RGGI investments in the region. Over their lifetime, the investments in beneficial electrification made in 2020 are expected to avoid 177,000 short tons of CO2 emissions and result in $90 million in customer bill savings. Beneficial electrification investments will yield even greater emissions reduction benefits over time, as renewables take up a larger portion of the electric grid composition. Investments in beneficial electrification programs, and the resulting bill savings, also lead to job creation and spur local economic activity.

In addition, some programs reported as energy efficiency, clean and renewable energy, or greenhouse gas abatement may include beneficial electrification components, but the outcomes of these projects are not reported under beneficial electrification.

Table 4: Benefits of 2020 RGGI Investments in Beneficial Electrification

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments*
Short Tons CO_2 Avoided	12,187	176,877
Energy Cost Savings**	$5,420,796	$89,589,982
MMBtu Saved	150,038	2,179,101
MWh Increased	10,089	151,330

*Although Beneficial Electrification is a new addition to the RGGI Proceeds report, Lifetime Benefits are calculated the same as other categories in the report. States use assumptions about the lifespan of their Beneficial Electrification investments in terms of years, and calculate lifetime benefits based on assumptions about their ISO's carbon intensity, energy cost, etc. over the lifespan of an investment to estimate Lifetime Benefits.

**Energy cost savings is the net result of increased MWh costs from beneficial electrification combined with the decrease in avoided fuel costs (i.e. heating oil, gasoline).

Greenhouse Gas Abatement

Greenhouse gas abatement (GHG abatement) is a broad category encompassing other ways of reducing greenhouse gases, apart from energy efficiency and clean and renewable energy. Approximately 5% of 2020 RGGI investments supported GHG abatement programs. Over their lifetime, the investments made in 2020 are expected to avoid the release of over 160,000 short tons of CO_2 (see **Table 5**).

Programs in the GHG abatement category may vary significantly, and may drive GHG emission reductions in multiple sectors. For example, technology, research, and development programs are tracked as GHG abatement, as they may lead to advancements resulting in the reduction of greenhouse gases. Climate change policy research is also tracked as GHG abatement.

GHG abatement programs vary in the types of benefits they provide. Some projects reduce electricity and fossil fuel use as part of their efforts to reduce overall emissions, generating economic benefits similar to those realized through energy efficiency and clean and renewable energy programs. Other projects may not return immediately trackable benefits within the scope of this report, but still provide important long-term benefits in climate preparedness and mitigation.

Table 5: Benefits of 2020 RGGI Investments in GHG Abatement

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments
Participating Households	2,999	n/a
Participating Businesses	28	n/a
Short Tons CO_2 Avoided	15,888	160,881
MMBtu Saved	222,821	2,228,214
Energy Bill Savings	$5,184,777	$51,847,774

Direct Bill Assistance

Direct bill assistance returns money to consumers as a rebate on their energy bills. Approximately 19% of 2020 RGGI investments have funded direct bill assistance. RGGI investments in direct bill assistance in 2020 returned $37 million in bill savings to energy consumers (see **Table 6**).

These programs provide rate relief to electricity consumers in the RGGI region. Some programs provide assistance specifically to low-income families, while other programs provide small on-bill credits to all consumers.

Direct bill assistance typically appears as a credit on a consumer's electricity bill. Direct bill assistance programs support economic activity by providing funds directly to consumers, who can then spend those funds on other priorities. Unlike energy efficiency or clean energy programs (which generate benefits for the lifetime of the installed measures), direct bill assistance programs provide benefits only for the length of the bill-assistance program. Direct bill assistance programs also do not reduce or affect wholesale electricity prices.

RGGI proceeds provide a small percentage of low-income direct bill assistance programs across the states. Other sources of funds come from on-bill system benefit charges, and federal funds in the case of LIHEAP programs.

Table 6: 2020 RGGI Investments in Direct Bill Assistance

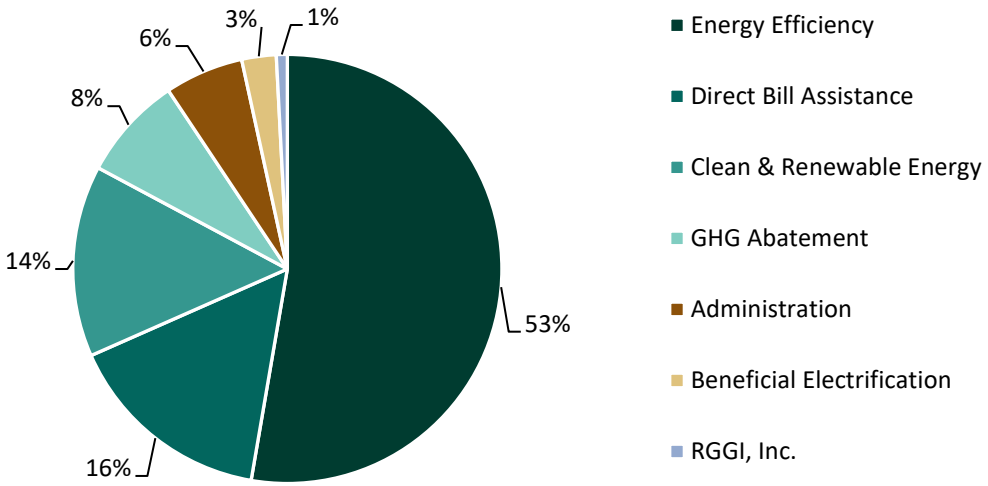
Category	Annual Benefits of 2020 Investments
Participating Households	722,874
Participating Businesses	38,580
Energy Bill Savings	$37,586,252

Cumulative Uses of Auction Proceeds

While this report focuses primarily on 2020 data, information on cumulative RGGI investments is provided in this section as an overview of RGGI's track record. **Chart 4**, below, shows the percentage of all-time RGGI investments directed to each of the major program categories.

This pie chart shows each program category as a percentage of all-time RGGI investments.

Chart 4: Cumulative RGGI Investments by Category



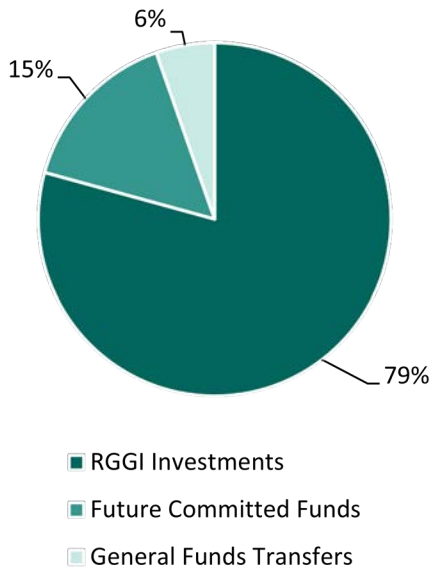
The states participating in RGGI invested $2.99B as of 2020.

RGGI investments are themselves a subset of total proceeds. Most RGGI proceeds through 2020 are defined as RGGI investments. Other uses of funds, such as transfers to state general funds, are outside the scope of this report. See **Chart 5**, below, for more details on total RGGI proceeds.

Two states report program data according to the fiscal year (July 1-June 30) rather than the calendar year. A fiscal year adjustment is used to compare numbers between fiscal-year and calendar-year states.

Chart 5: RGGI Investments as a Subset of Total Proceeds

Description	Funds
All Proceeds through Dec. 31, 2020	$3,801,985,568
Adjustment for Fiscal Year Reporting	-$39,673,943
General Funds Transfers	$199,700,000
Future Committed Funds	$571,395,708
RGGI Investments	**$2,991,215,917**



The pie chart shows three categories of funds, as a percentage of all proceeds **after** the fiscal year adjustment. The participating RGGI states invested $2.99B in the period covered by this report. This leaves $571M in funds that are yet to be invested.

All-time benefits metrics may be best understood as a general indication of the cumulative benefits of RGGI-funded investments since the program's inception. **Table 7** shows that the track record from all RGGI investments includes benefits on the order of billions in customer bill savings, and tens of millions of short tons of CO_2 avoided. Note that as the program's track record grows longer, all-time numbers may include changes in states' methodologies from year to year.

Table 7: All-Time Benefits of RGGI Investments

Category	Lifetime Benefits of All RGGI Investments
Participating Households	7,237,334
Participating Businesses	293,137
Short Tons CO_2 Avoided	49,523,308
Megawatt-Hours Saved	74,527,807
MMBtu Saved	255,317,388
Energy Bill Savings	$14,816,129,607

Previously reported cumulative data plus 2020 data may not sum exactly to updated cumulative data. This is due to state adjustments or corrections to prior cumulative calculations.

Connecticut

Connecticut primarily invests RGGI auction proceeds towards programs dedicated to the deployment of energy efficiency measures and improvements, and financing options for renewable energy projects. Connecticut allocates 69.5% of its auction proceeds to support the energy efficiency programs overseen by the Connecticut Energy Efficiency Board (CEEB) and administered by Eversource Energy and The United Illuminating Company, as well as those of the Connecticut Municipal Electric Energy Collective (CMEEC) and the Town of Wallingford – Electric Division (WED). Connecticut further allocates 23% to the Connecticut Green Bank to support the development of Class I renewable energy sources. The Department of Energy and Environmental Protection retains the remaining 7.5% for administrative purposes.

During 2020, Connecticut invested RGGI auction proceeds in the following programs:

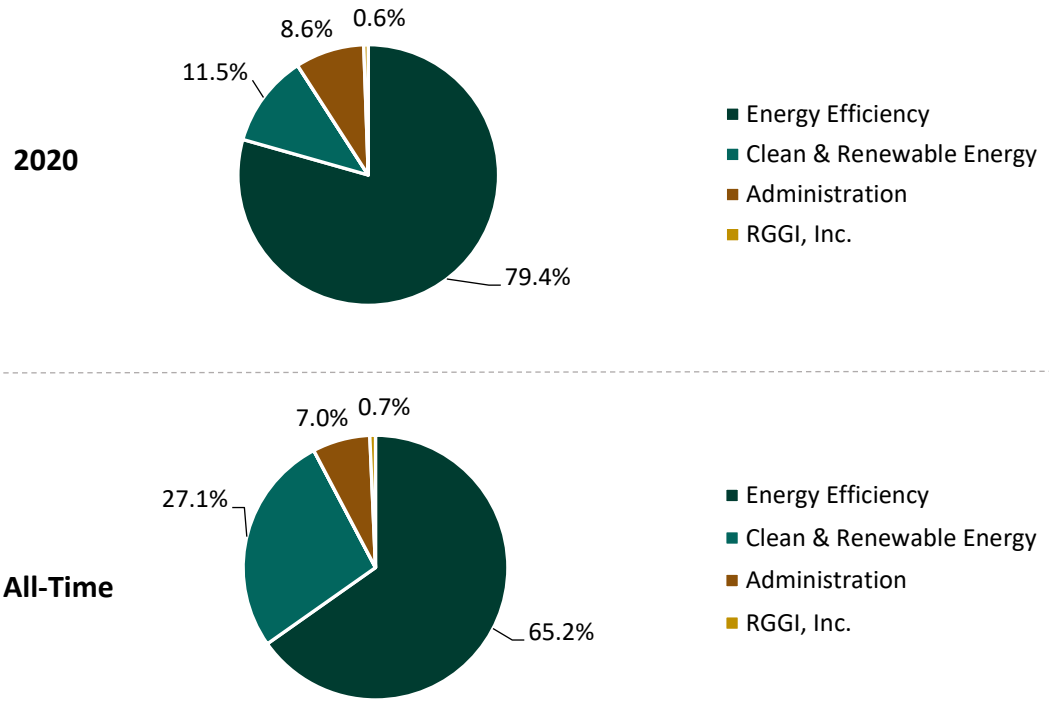
- Home Energy Solutions^{SM} Program: Under this program, Eversource Energy and The United Illuminating Company invested RGGI funds to conduct residential energy audits and install weatherization measures. Due to the investment of RGGI funds, Eversource and UI were able to extend participation to more than 8,000 homes in 2020 and avoid more than 12,000 tons of CO_2 emissions and conserve over 154,000 MMBtus of fossil fuel use.
- Home Energy Savings Program: Under this program, WED leveraged RGGI funds to perform residential energy audits and deploy weatherization measures. In 2020, WED served 198 homes and provided weatherization services to 108.
- Commercial Property Assessed Clean Energy (C-PACE) Program: Under this program, the Connecticut Green Bank offers low interest, zero-down payment financing for clean and renewable energy projects. In 2020, the Connecticut Green Bank invested RGGI proceeds in C-PACE to help finance eleven projects, four of which were completed in 2020. The remaining seven projects were completed in 2021. Since the inception of the C-PACE program, 111 projects have been completed.
- Various energy efficiency projects: CMEEC used RGGI funds toward the deployment of residential and commercial energy efficiency projects, ranging from the installation of heat pumps and mini splits to street lighting upgrades including the retrofit of street lighting on University of Connecticut's (UCONN) Avery Point campus.

Connecticut has cumulatively invested nearly $214 million in RGGI allowance proceeds toward programs and services dedicated to the deployment of energy efficiency measures and renewable energy technologies.

The American Council for an Energy-Efficient Economy (ACEEE) nationally ranked Connecticut seventh in its 2021 State Energy Efficiency Scorecard, which evaluated 2020 state energy efficiency efforts. Connecticut's continued Top Ten ranking is attributed to a range of energy-saving policies across the entire economy including:

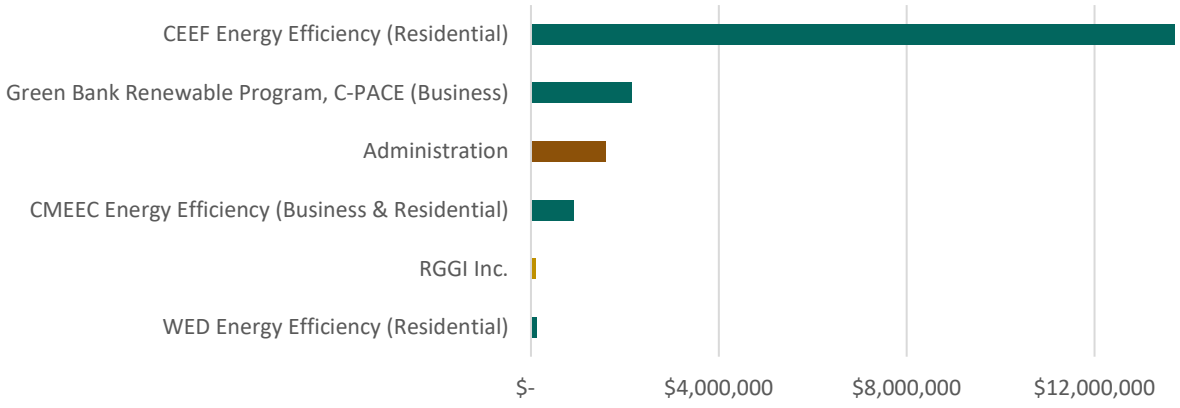
- Incentives for high-efficiency vehicles and adoption of California's ZEV program.
- Waivers of co-pays for certain energy efficiency programs to mitigate impacts from the COVID-19 pandemic.
- Launch of the Equitable Energy Efficiency Proceeding in order to increase participation in energy efficiency programs by members of communities that have traditionally been underrepresented.

Chart 6: 2020 Connecticut RGGI Investments by Category



Connecticut received $246M in proceeds from 2008-2020. RGGI investments represent $18.6M in 2020, and $214M cumulatively. $4M is committed to 2021 and future investments.

Chart 7: 2020 Connecticut RGGI Investments by Recipient



Connecticut RGGI investments represent $18.6M in 2020.

Program Highlight: Home Energy Solutions℠

The Home Energy Solutions℠ (HES) program is a home energy efficiency audit and energy conservation program, primarily funded by mandated conservation charges collected from electric and natural gas ratepayers, who in turn can receive its services. Connecticut's investment of RGGI proceeds in this program has provided funding for the deployment of services under the program to families who heat their homes with fuel oil or propane.

The HES program enables evaluation of a home's energy performance and installation of core weatherization and energy-saving measures such as sealing air leaks, installing energy-efficient lighting such as LEDs, faucet aerators, low-flow showerheads, and weather stripping. Participation in the HES program requires a co-pay, however, for much of 2020, the co-pay was waived in response to the emergence of the COVID-19 pandemic.

The HES program also provides families with customized reports highlighting additional opportunities and estimated cost savings for implementing deeper energy-saving measures. Participants may also receive rebates on these interventions such as improving insulation and installing energy-efficient mechanical equipment. HES participants may also be provided with the Department of Energy's Home Energy Score for their home, a standardized comparison of the home's energy usage to similar buildings, and recommendations for energy upgrades along with the estimated annual savings from those upgrades. HES participants can be provided with up to $7,500 in rebates to perform energy efficiency and equipment upgrades such as installation of ENERGY STAR rated appliances and improved home insulation. Low-interest rate financing options are also available. The average home in Connecticut receives about $1,000 in services and realizes $200-$250 in savings on their annual energy bills.

Success Story: UCONN at Avery Point

The UCONN at Avery Point campus, located on Long Island Sound at the mouth of the Thames River in Groton, CT is a public campus of the University of Connecticut offering liberal arts programs of study for approximately 564 enrolled students.

Groton Utilities (GU), a member of CMEEC, provides and maintains streetlights to this 72-acre campus. The recognition of the need to upgrade the pole top lighting fixtures was the catalyst for GU to embark on the replacement of the 121 high pressure sodium fixtures (175W each) with LED fixtures (99W each). The expenditure of $242,675 of RGGI funds for the UCONN at Avery Point project is anticipated to realize an annual energy savings and reduction in monthly peak demand of 53 MWh and 13 kW, respectively, and an estimated reduction of GHG emissions equivalent to 25 tons of CO_2.

Resources:

- ACEE State Energy Efficiency Scorecard
- C-PACE
- CMEEC
- Energy Efficiency Board 2020 Programs and Operations Report
- Energize Connecticut℠
- Home Energy Solutions℠ Core Services
- Town of Wallingford – Electric Division

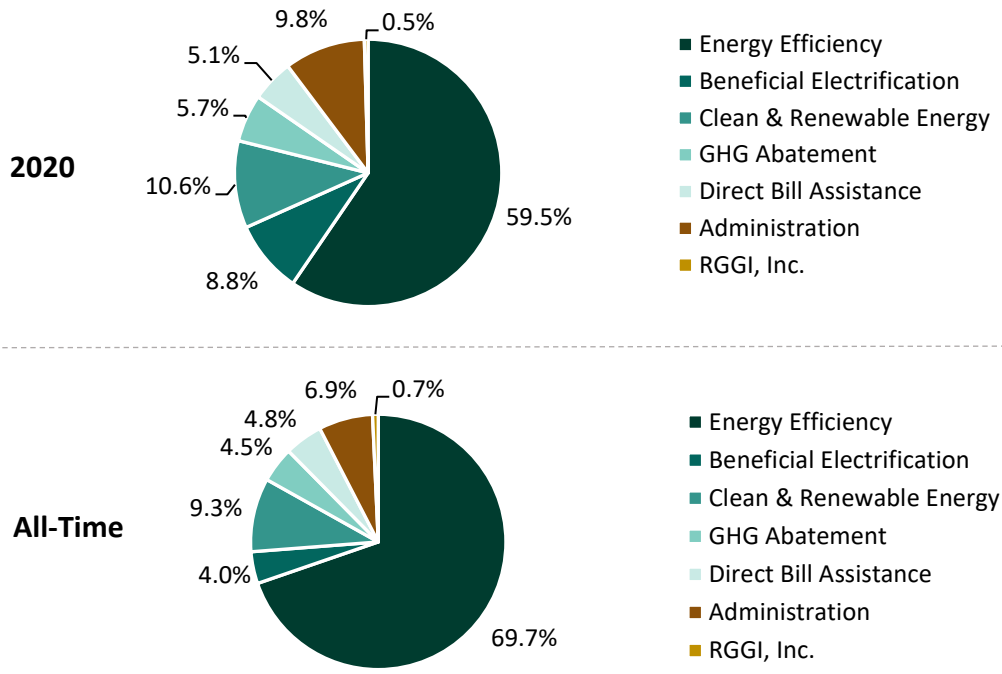
Delaware

Delaware invests RGGI allowance proceeds in a variety of programs that reduce energy use, reduce greenhouse gas emissions, and assist low-income families with energy bill payments. The suite of programs funded with RGGI allowance proceeds provides Delaware families and businesses with valuable assistance with energy efficiency improvements while providing opportunities for innovation in greenhouse gas reductions.

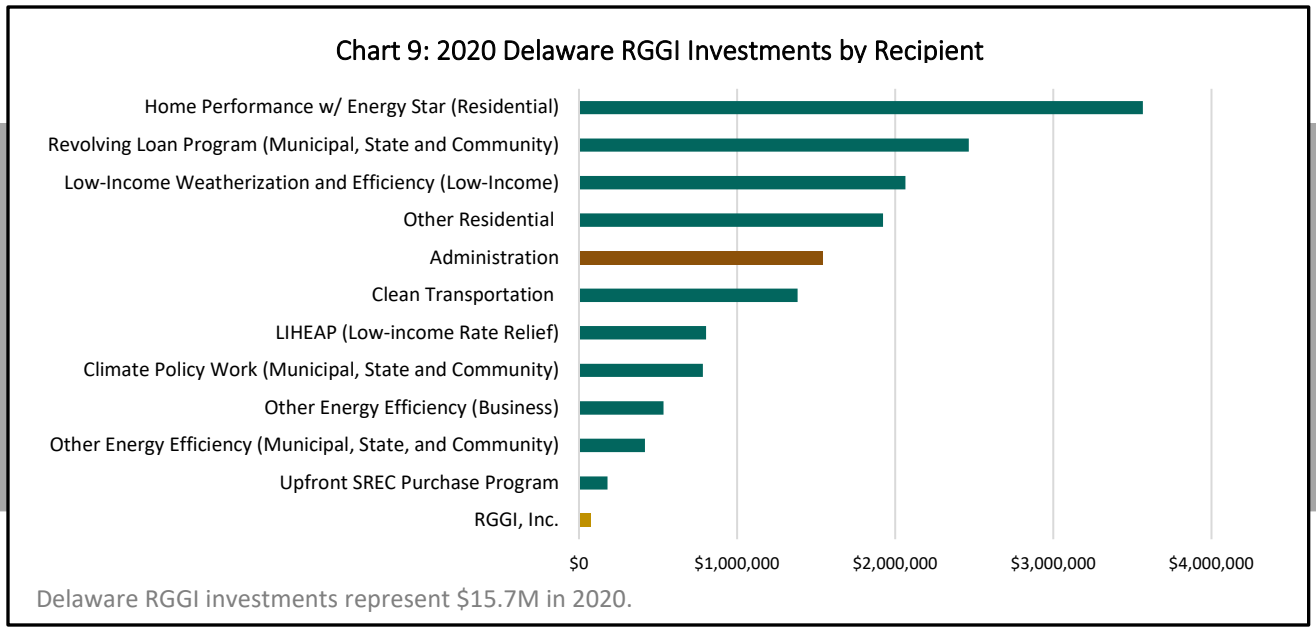
Delaware directs 65% of its allowance proceeds to the Delaware Sustainable Energy Utility (SEU). The SEU serves Delawareans by promoting the use of affordable, reliable, clean energy, and providing a variety of incentives for energy efficiency improvements.

In addition, Delaware directs ten percent of its allowance proceeds to the Delaware Department of Natural Resources and Environmental Control (DNREC) for development of innovative programs to reduce greenhouse gas emissions such as the Clean Transportation incentive program and infrastructure grants. Ten percent of proceeds is also directed to DNREC to implement the state's Weatherization Assistance Program which provides no-cost upgrades to homes to decrease energy use and decrease bills. Five percent of proceeds is also directed to a program to reduce energy bills for low-income customers. The remaining ten percent is reserved for administration of programs.

Chart 8: 2020 Delaware RGGI Investments by Category



Delaware received $149.8M in proceeds from 2008-2020. RGGI investments represent $15.7M in 2020, and $148.8M cumulatively. $1.3M is committed to 2021 and future programs.



Program Highlight: DESEU-Energize Delaware Home Performance with ENERGY STAR

The SEU flagship Home Performance with ENERGY STAR® program is going into its eighth year. This program offers a "whole house" approach to improving comfort and safety in the home and provides homeowners significant savings on their utility costs. Delaware homeowners learn ways to improve the energy efficiency of their homes through completion of a subsidized, comprehensive home energy assessment performed by certified contractors, and they also receive up to $200 of energy saving items such as LED light bulbs and pipe insulation.

After the assessment, homeowners making recommended energy-saving improvements can take advantage of rebates that make their home projects affordable. Reduced assessment costs and increased rebates are available to income-qualified Delawareans and also to property owners residing in Delaware's designated "Downtown Development Districts." Of the 1,749 home assessments completed in 2020, 1,196 homeowners received rebates. In total, SEU leveraged $3.5M in RGGI funds for the Home Performance with ENERGY STAR Program in calendar year 2020, resulting in about $490,000 in energy bill savings and over 2,000 metric tons CO_2 emissions avoided.

Success Story: Delivering Savings through Home Performance with ENERGY STAR

Delawareans and families across the country are experiencing higher utility costs and more strain on their budgets due to the COVID-19 pandemic. Even during the pandemic, SEU was able to keep the Home Performance with ENERGY STAR program operating and participating contractors working in a safe and efficient manner to provide home energy assessments and rebates for energy efficiency heating and cooling equipment, air sealing and insulation, and other water heating and weatherization measures. SEU provided reduced costs for the energy assessments, increased rebate amounts, and provided incentives for completed applications to keep contractors working and making projects more affordable during the pandemic. Rob and Cami Seward provided the following testimonial of their experience as 2020 participants in SEU's Home Performance with ENERGY STAR program:

"We were running an alternate A/C unit in the dining room and it was still 90 degrees in the house. This year is different! Because of your work evaluating our house and sealing and insulating the attic, it has been cool and comfortable all summer. No extra A/C unit needed! Our electric bill last July was $349 and this July it was $201. What a dramatic improvement! We are so happy with the house now that the work has been completed. Great Job sealing us up and cooling us down—We are so grateful to the Energize Delaware Team!"

Maine

The Efficiency Maine Trust (Efficiency Maine) is the independent administrator for programs to improve the efficiency of energy use and reduce greenhouse gases in Maine. The Trust does this primarily by delivering financial incentives on the purchase of high-efficiency equipment or changes to operations that help customers save electricity, natural gas, and other fuels throughout the Maine economy. The organization's purposes include the following:

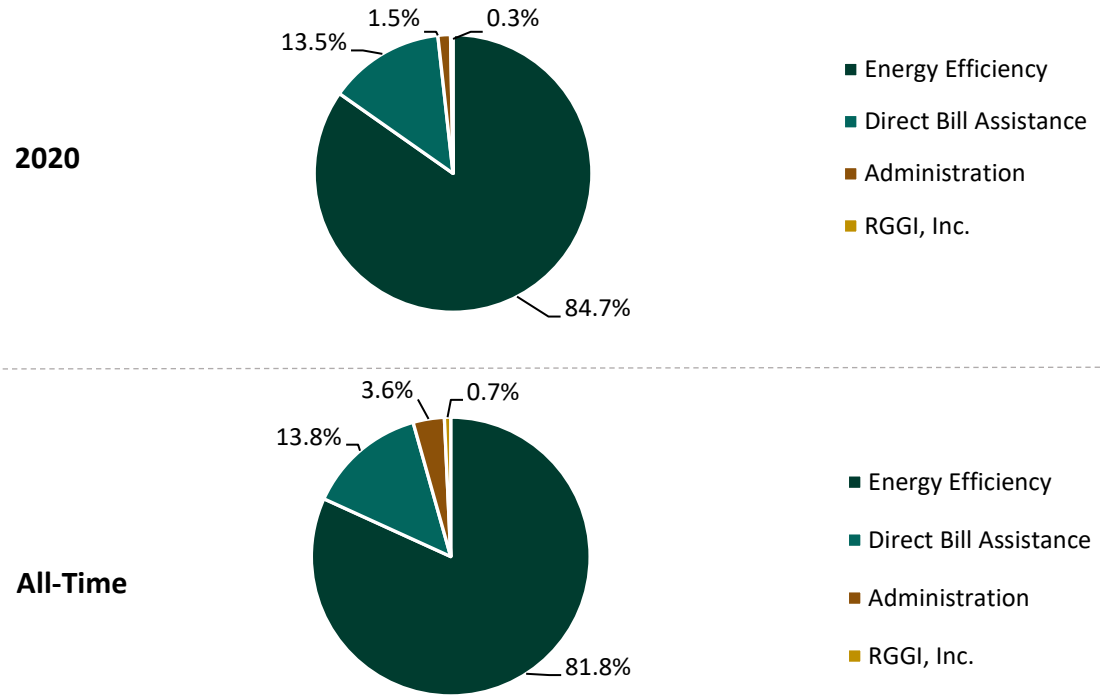
- Consolidating under one roof the funds for Maine's consumer-focused efficiency and alternative energy programs for all fuel types, including electric, natural gas, and unregulated fuels;
- Procuring distributed energy resources (such as efficiency and alternative energy) that cost less than traditional energy to help individuals and businesses meet their energy needs at the lowest cost; and
- Helping transform the energy market in Maine so that energy-efficient products, alternative energy equipment, and related energy services are more accessible and affordable to end-use customers.

Efficiency Maine's programs are funded primarily by a combination of electric and natural gas system benefit charges, Forward Capacity Market proceeds, and RGGI proceeds. During its 2020 fiscal year (FY2020), Efficiency Maine invested over $7.4 million in RGGI proceeds, directing approximately 98% towards a combination of energy efficiency programs and rate relief for large manufacturers; the remaining 2% went towards general administration. Though nearly all of Efficiency Maine's programs leveraged RGGI funding to some degree in FY2020, the bulk of funds were invested through the following five programs:

- *Home Energy Savings Program:* Drove market-based home weatherization and heating demand reduction by offering rebates and loans, providing customer education, and developing a vendor network.
- *Distributor Initiatives:* Rebated high efficiency boilers and furnaces to homes and businesses through the distributor channel
- *Retail Initiatives:* Rebated efficient wood stoves and pellet stoves in retail stores to heat the homes of Mainers
- *Commercial and Industrial (C&I) Prescriptive Program:* Provided fixed-price incentives for a prescriptive suite of "off-the-shelf" energy efficiency measures for C&I customers.
- *C&I Custom Program:* Targeted larger C&I customers by offering incentives for custom, site-specific energy efficiency projects that require unique engineering analyses.

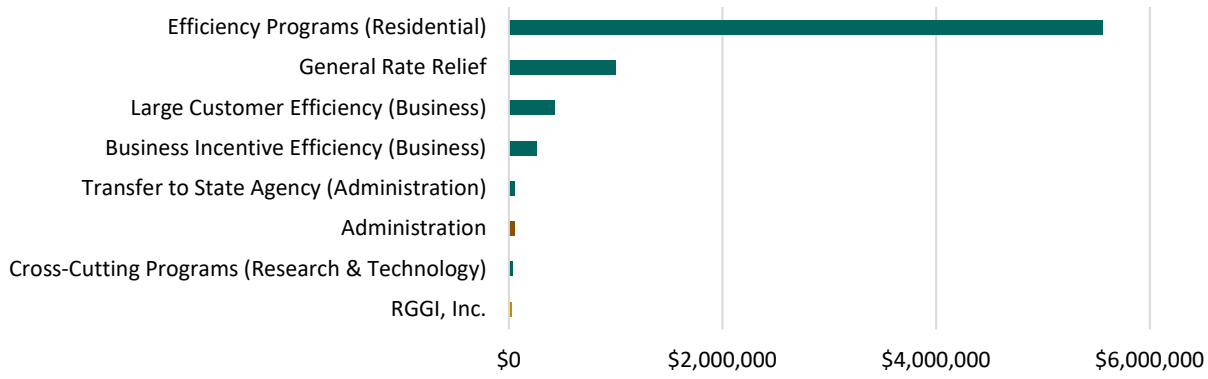
Over the lifetime of the investments made in FY2020, Maine's RGGI-funded efficiency measures are estimated to generate savings of over 2.15 million MMBtu in avoided consumption of natural gas and other heating or process fuels. These investments will lower participants' energy bills by more than $41 million.

Chart 10: 2020 Maine RGGI Investments by Category



Maine received $122.8M in proceeds from FY08-FY20. RGGI investments represent $7.4M in FY20, and $103M cumulatively. $13.4M is committed to 2021 and future programs.

Chart 11: 2020 Maine RGGI Investments by Recipient



Maine RGGI investments represent $7.4M in 2020.

Program Highlight: Home Energy Savings Program

Efficiency Maine's Home Energy Savings Program (HESP) serves as the framework for market-based residential weatherization and heating system improvements achieved through a combination of rebates, financing, and customer education. HESP raises awareness about the benefits of home weatherization and encourages Maine homeowners to make energy efficiency upgrades. Efficiency Maine's Low-Income Initiatives leverage this market-

based channel to target low- and moderate-income (LMI) customers by providing enhanced incentives for home weatherization (with an energy assessment) and high-performance heat pumps.

In the past, Efficiency Maine's ability to promote these tailored offerings to low-income households was limited; it required that participants be enrolled in the federally funded Low-Income Home Energy Assistance Program (LIHEAP). In 2017, the Maine State Housing Authority estimated that there were up to 176,000 low-income homes in Maine, yet only 40,000 were enrolled in LIHEAP. In FY2017, Efficiency Maine expanded eligibility criteria for this initiative to include LMI customers enrolled in any state or federal income-based program, as well as owners living in mobile homes and those living in homes with assessed property values below a certain threshold.

These eligibility changes, along with enhanced incentives, have helped drive dramatic growth in activity in Efficiency Maine's market-based LMI initiative. Indeed, overall participation rose from 40 homes in FY2016 to 1,444 homes in FY2021. (Though the COVID-19 pandemic initially dampened this growth trend in FY2020, data from FY2021 showed a strong rebound.) Rebates for heat pumps covered 1,213 units over the course of FY2021, up from 144 units in FY2017. The larger pool of potential customers and simplified criteria made this approach significantly easier for staff, contractors, and community organizations to promote Efficiency Maine's LMI offerings, and for participants to access it.

Overall, Efficiency Maine's market-based LMI offerings leveraged $15,000 in RGGI funds in FY2020. Low-income Mainers save an estimated 172 MMBtu annually in avoided energy consumption associated with heating oil and other fuels.

Success Story: Bath Iron Works

Bath Iron Works (BIW) is a major shipyard that has been building U.S. Navy warships in Bath, ME for over 100 years. The primary structural assembly building is nearly 170,000 square feet with 80-foot ceilings. It houses the majority of the facility's welding operations.

Originally, the assembly building's heat was provided by 19 Modine unit heaters equipped with steam coils. The building operated at a significant negative pressure; exhaust fans pulled air out of the building, and uncontrolled make-up air came in through infiltration. In these conditions, the building experienced fume accumulation, cold temperatures, and considerable energy loss. BIW therefore launched an effort to upgrade the building with the goals of improving air quality, increasing winter space temperature, reducing the negative pressure, and saving energy.

BIW's new high-efficiency air filtration units.

BIW received two separate proposals for new air filtration and make-up air systems – one high-efficiency, more expensive option, and one lower-efficiency, cheaper option. Both systems would accomplish the company's general goals for the project. By offering a financial incentive to defray the upfront incremental cost differential, Efficiency Maine was able to encourage BIW to select the high-efficiency alternative.

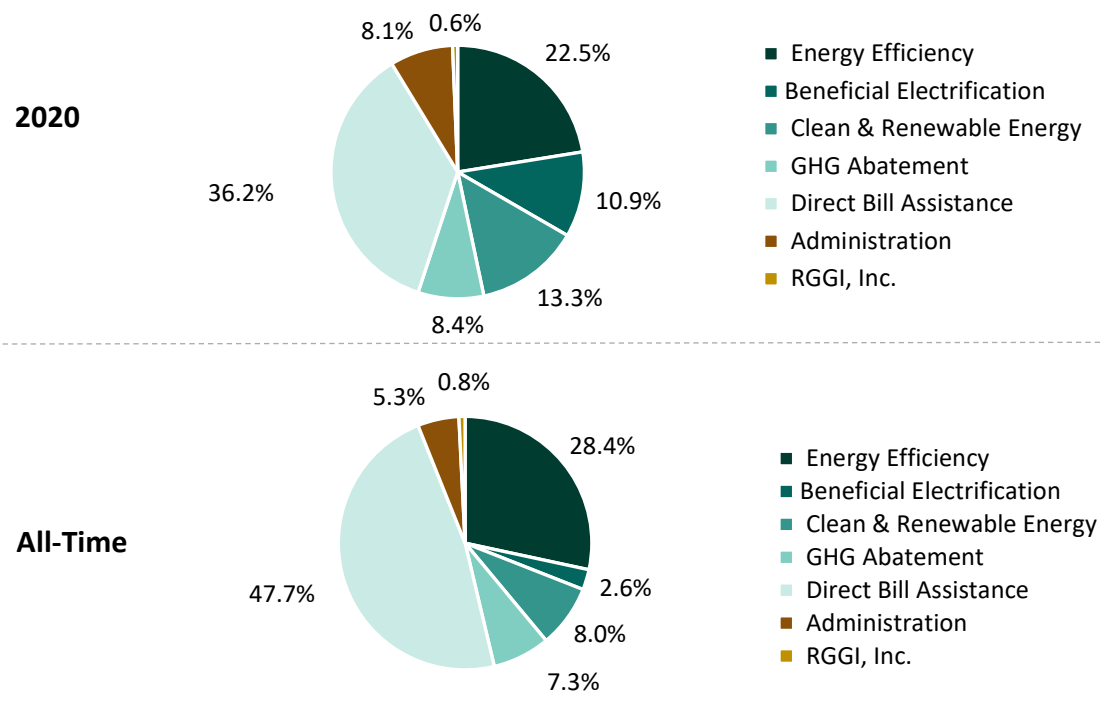
Given the relatively complex, site-specific nature of the project, BIW worked with Efficiency Maine's Commercial and Industrial (C&I) Custom Program. The program was able to validate the predicted energy impacts and offer a $752,000 incentive, funded partially with RGGI dollars. These investments will save BIW approximately 2.7 million kWh of electricity and 7,900 MMBtu of natural gas annually, reducing the company's operating costs for years to come.

Maryland

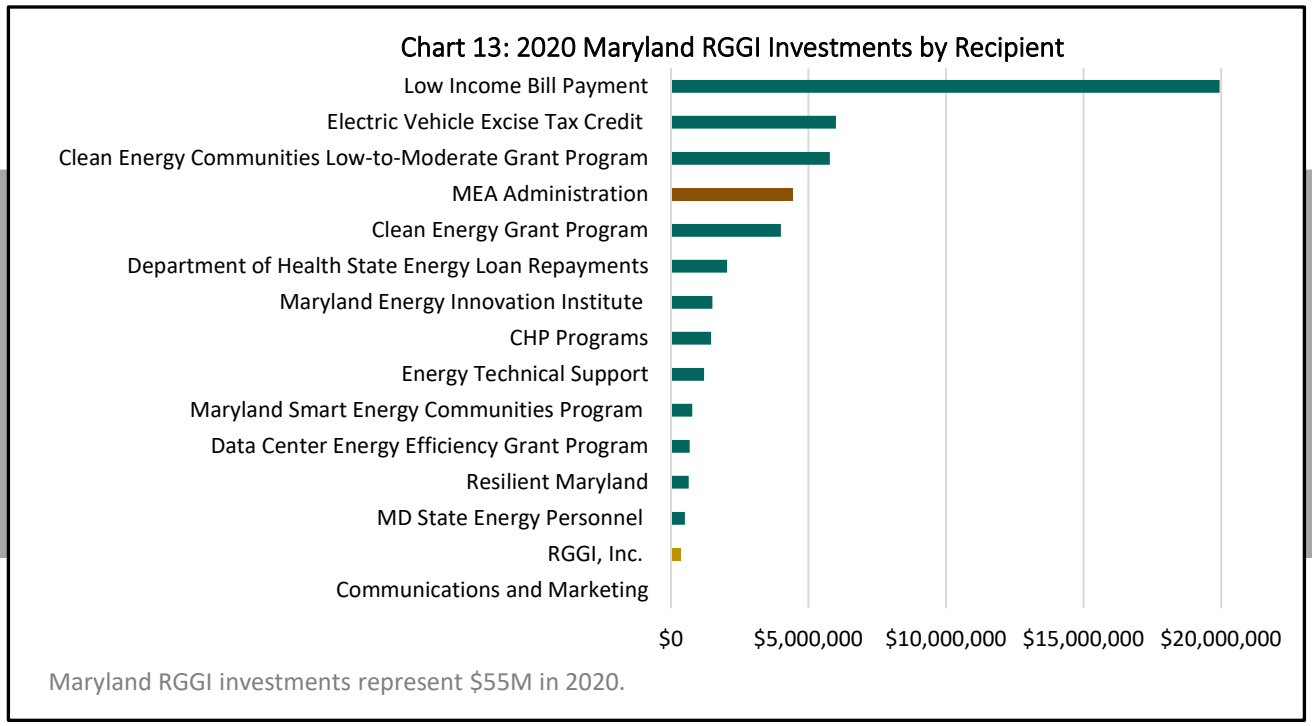
Maryland allocates proceeds from the sale of CO_2 allowances into the State's Strategic Energy Investment Fund (SEIF)—a special, non-lapsing fund administered by the Maryland Energy Administration (MEA). MEA deploys SEIF funds to promote affordable, reliable, and clean energy across Maryland's diverse regions and communities.

These programs are intended to reduce energy bills, create jobs in growing industries, help reduce greenhouse gas emissions, increase resiliency, and promote energy independence.

Chart 12: 2020 Maryland RGGI Investments by Category



Maryland received $736.8M in proceeds from 2008-2020. RGGI investments represent $55.0M in 2020, and $711.3M cumulatively. $25.5M is committed to 2021 and future programs.



Success Story: Public School Data Center Team Puts Energy Efficiency Lessons into Action

The Maryland Energy Administration (MEA) continues to develop innovative energy programs that drive economic development, energy resilience and recovery for Marylanders. Maryland was the first in the nation to offer a targeted energy efficiency program for data centers with the Data Center Energy Efficiency grant. Data centers use 100 – 200 times more energy than a typical office building, running 24 / 7 / 365. MEA provides Clean Energy Rebates to businesses, nonprofits, local governments, and State of Maryland government agencies and departments that install clean energy systems on facilities located in the state.

Data centers provide round-the-clock sensors to monitor power, temperature, humidity, fire, and other mechanical functionals for critical IT infrastructure. In 2017, US data centers required more than 90 billion kilowatt-hours of electricity, equal to the energy generated from 34 massive coal-powered plants. Energy efficiency at data centers has never been more important. Montgomery County Public Schools (MCPS) received a $127,000 Maryland's Data Center Energy Efficiency Grant (DCEEG) in 2018, to install more energy efficient technology in their data center. MCPS's data center operates, monitors, and provides technical support for central servers and related equipment allowing 24-hour access to essential student and administrative databases as well as payroll, student attendance and enrollment, retirement, asset management, financial management, report cards, and online ordering. MCPS implement numerous upgrades including server virtualization, replacement, and migration of storage area networks to reduce energy consumption of servers. Air flow optimization measures such as rack enclosure cooling blanking panels were also implemented, all as part of a multiphase data center improvement project. These upgrades are expected to save MCPS over $21,000 annually or 180,695 kilowatt hours, which is enough to power roughly 600 laptop computers for 8 hours. This project was co-sponsored by MCPS' Office of Technology and Innovation (OTI) and Department of Facilities Management's (DFM) Energy Resource Team. MCPS hopes to reinvest the grant funding to procure software that will give insight into actual server energy usage that is not presently available. This would facilitate and encourage informed decisions in prioritizing and pursuing larger ticket/cost items where greater energy savings and efficiencies could be realized. Before this project, MCPS did not consider energy efficiency or ENERGY STAR™ ratings when purchasing equipment.

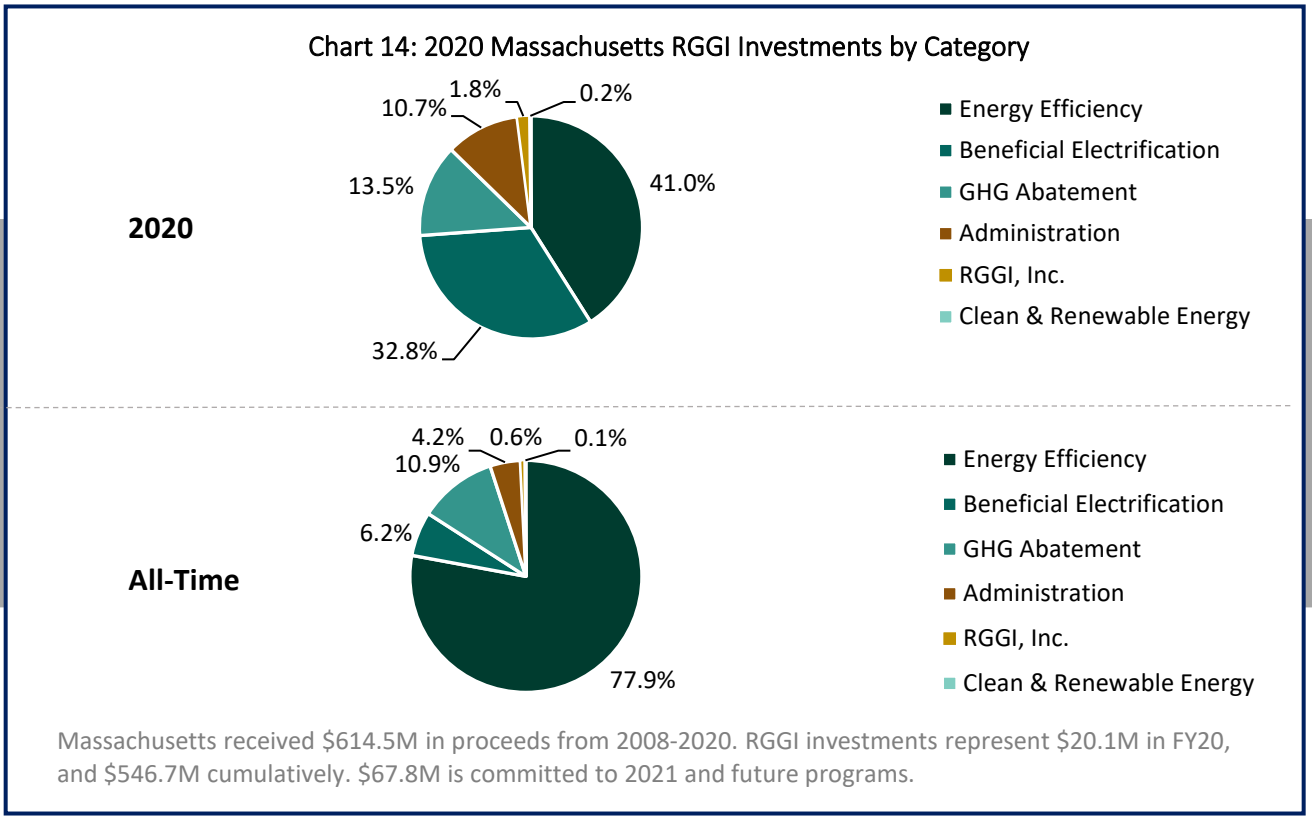
Massachusetts

Massachusetts leads the nation with bold and transformative policies and practices to address climate change. Signed into law in 2008, the *Global Warming Solutions Act (GWSA)* established a statewide limit on greenhouse gas (GHG) emissions of 25 percent below 1990 levels for 2020 and 80 percent below 1990 levels by 2050.[2] In 2020, Governor Baker signed *An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy*, further committing the Commonwealth to net zero emissions in 2050.[3]

Massachusetts was one of the first states in the nation to set aggressive economy-wide goals to reduce GHG emissions across the electricity, thermal, and transportation sectors and enact a suite of policies and practices to reach those goals. However, emissions from the transportation sector remain the states' foremost challenge in reaching its goal of net zero emissions in 2050. Transportation is the largest source of GHG emissions, and it continues to grow.

The aggregate emissions of the light-duty fleet of vehicles on Massachusetts roads is determined by a combination of the makeup of registered vehicles and the number of miles driven. The overall composition of the state's registered vehicles changes over time as new vehicles are purchased, old vehicles that no longer function or pass inspection are removed, and vehicles move in and out of state. Persuading new vehicle buyers to purchase an electric vehicle (EV) instead of a gasoline vehicle reduces future emissions from the transportation sector as vehicle purchases today determine the composition of the fleet for the vehicle's lifetime.

Chart 14: 2020 Massachusetts RGGI Investments by Category

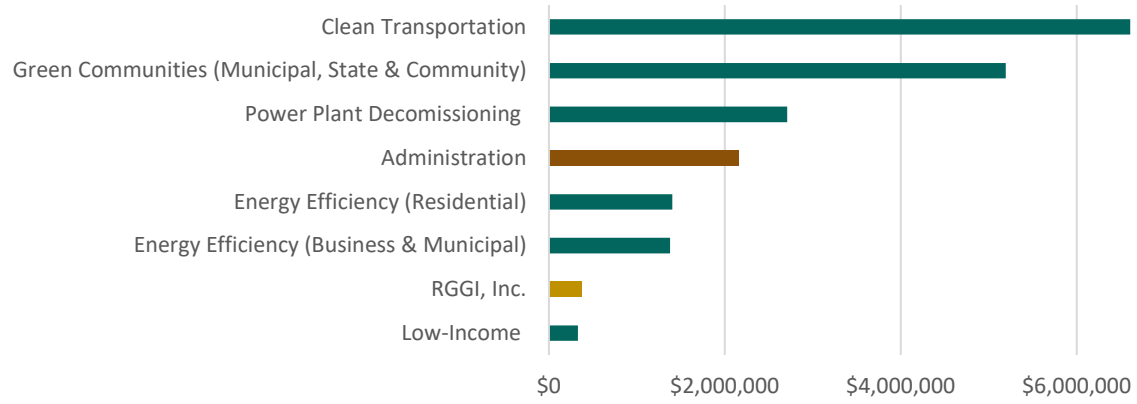


Massachusetts received $614.5M in proceeds from 2008-2020. RGGI investments represent $20.1M in FY20, and $546.7M cumulatively. $67.8M is committed to 2021 and future programs.

[2] An Act Establishing the Global Warming Solutions Act. Chapter 298 of the Acts of 2008, and as codified at M.G.L. c. 21N (Chapter 21N). Available at: https://malegislature.gov/laws/sessionlaws/acts/2008/chapter298

[3] Mass.gov. Press Release. Governor Baker Signs Climate Legislation to Reduce Greenhouse Gas Emissions, Protect Environmental Justice Communities. March 26, 2021. Available at: Governor Baker Signs Climate Legislation to Reduce Greenhouse Gas Emissions, Protect Environmental Justice Communities | Mass.gov

Chart 15: 2020 Massachusetts RGGI Investments by Recipient



Massachusetts RGGI investments represent $20.1M in 2020.

Program Highlight: MOR-EV

Launched in 2014, the *Massachusetts Offers Rebates for Electric Vehicles* (MOR-EV) program is an education and rebate program funded by the Executive Office of Energy and Environmental Affairs (EEA) and Department of Energy Resources (DOER) and is administered by the Center for Sustainable Energy (CSE) to increase the number of zero-emission vehicles (ZEVs) on roadways and reduce Massachusetts transportation sector GHG emissions. The MOR-EV program is designed to reduce GHG emissions in the transportation sector by influencing buyers to purchase an EV rather than a traditional gasoline-powered vehicle.

The program objective is to provide air pollution emission reductions for the Commonwealth by increasing the use of ZEVs MOR-EV offers rebates of up to $2,500 per electric vehicle and educates consumers and dealers about ZEV rebates and benefits. In 2020, more than 2,700 rebates were approved.

MOR-EV supports the Commonwealth's goals to reach 300,000 ZEVs on the roads by 2025. The program is designed to accelerate deployment of ZEVs in the Commonwealth by incentivizing residents to purchase or lease vehicles that will help:

- Reduce GHG emissions that contribute to climate change
- Protect public health and air quality by reducing transportation-related air pollution that contributes to smog formation and related health effects such as asthma and heart attacks
- Enhance energy diversity and security
- Save drivers money
- Promote economic growth in the Commonwealth

In 2020, the MOR-EV program avoided the use of nearly 23,000 barrels of oil used by light duty vehicles. The Commonwealth's program succeeded in avoiding more than 127,000 MMBtu and reducing GHG emissions by 10,317 short tons.

From its inception in 2014, the program has gone through several iterations, with an eye for changes towards improvement. A cost effectiveness report is currently being undertaken to examine the role of such changes within the program scope.

MOR-EV was one of the first programs of its kind in the United States and the performance of the program to date offers many lessons learned. As with any new initiative, there are successful aspects of the program as well as opportunities for improvement. Three challenges of the current program are financial sustainability, cost-effectiveness, and equity. These issues are high priorities for the next phase of the program, and the opportunities presented are focused on achieving these three priorities.

Success Story: Green Communities

The city of Methuen used its $268,640 Green Community Designation Grant to install three energy efficiency measures at its public library, new pumps and motors at a sewer pumping station, efficiency upgrades at the water treatment plant, new heating equipment at fire stations, and to replace insulation and vapor barriers on rooftop ductwork at an elementary school. These projects will save the city an estimated $31,000 a year in energy costs and reduce annual emissions due to municipal operations by 89 tons.

Three projects at the Nevins Library were designed to improve energy efficiency of the historic municipal building's heating and ventilation systems.

- Project #1 - Installation of demand controls to enable central programming and automation of heating, ventilation, and cooling.
- Project #2 - Installation of variable frequency drive controls for more efficient timing operation of air handling unit fan motors.
- Project #3 - Replacement of two outdated, inefficient fan motors of air handling unit pumps. This project was added as project team made a determination that two of the four air handling unit motors needed to be replaced to maximize energy efficiency benefits.

The sewer Pump and motor replacement involved replacing two obsolete pumps & motors at the Bolduc Street sewer pumping station in West Methuen.

The Bolduc Street station is the city's second largest sewer pump station. The two old 25-horsepower 3-phase motors, in addition to inefficient energy usage, required extensive maintenance for operation, including frequent cleaning and regular reassembly of both pumps. The new pumps have significantly reduced clogging of materials and maintenance costs at the station.

At the water treatment plant, grant funds supported the installation of two variable frequency drives to enable more efficient timing operation at the plant's hot water secondary pumps and the installation of an air source heat pump at the plant's backup generator facility. This will provide for more efficient pre-heating of the back-up generator system's engine block.

Two fire stations received heating equipment upgrades. An outdated, inefficient furnace heating office and living space on the second floor of the Central Fire Station was replaced with a more efficient gas-fired unit. Garage bay unit heaters at the North Fire station were replaced with more efficient models.

The final project replaced aging insulation and vapor barriers supporting a rooftop unit on an elementary school.

New Hampshire

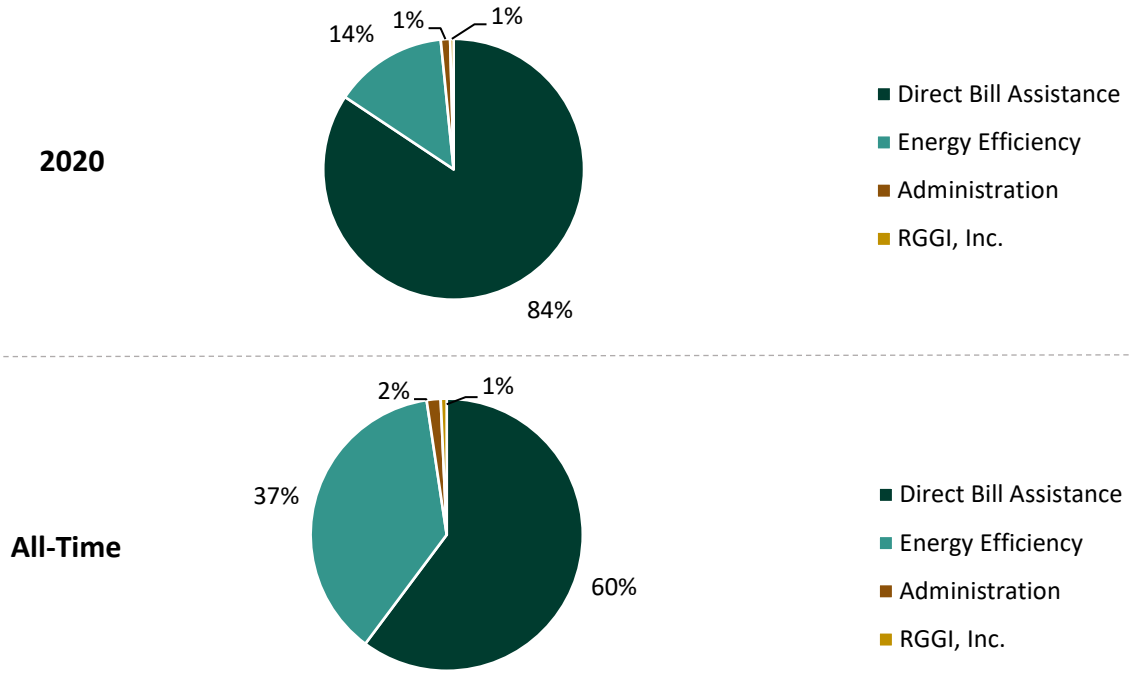
New Hampshire invests RGGI allowance proceeds in a variety of programs that reduce energy use in municipal and retail buildings, commercial and industrial facilities, and low-income households. RGGI allowance proceeds also provide direct bill assistance to reduce electric bills.

In 2020, New Hampshire received approximately $18.8 million in RGGI allowance proceeds, of which approximately $2.5 million was allocated to the Energy Efficiency Fund (EEF). The state's four electric utility companies administer energy efficiency fund programs through the EEF in combination with funds collected through the System Benefits Charge. Approximately $15.8 million was used to provide direct bill assistance to New Hampshire electric consumers, $0.1 million was allocated to an energy efficiency program focusing on moderate-income households, and the remaining RGGI auction proceeds of approximately $0.3 million covered RGGI-related administrative expenses.

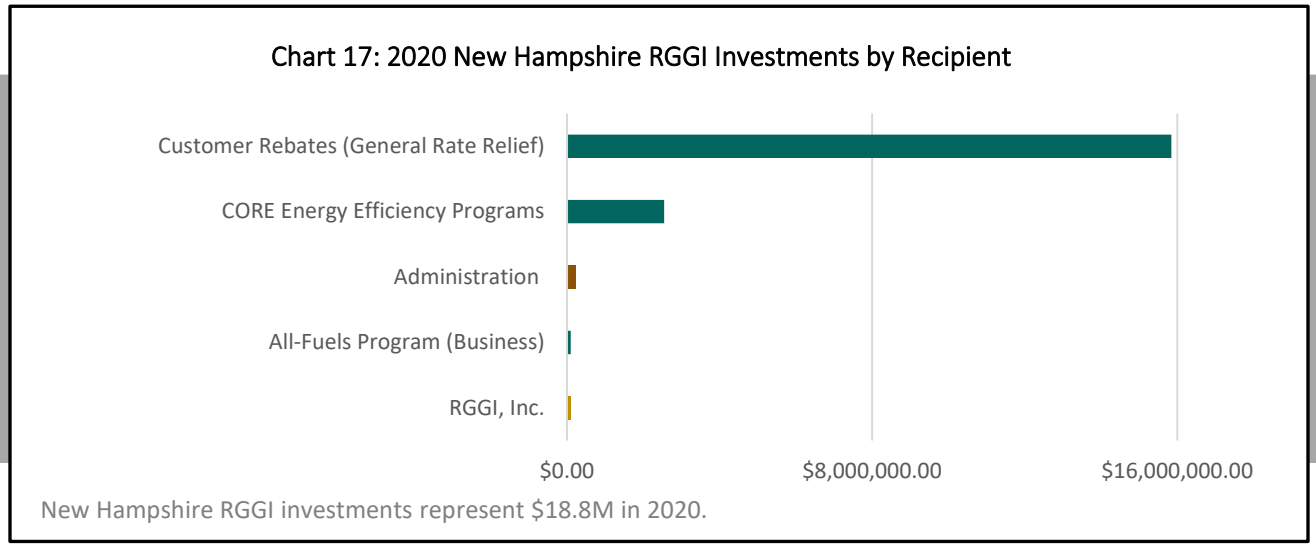
The state's electric utility companies' energy efficiency programs supported by RGGI funds include: a Municipal program; an income-eligible Home Energy Assistance program; and an All-Fuels weatherization program targeting moderate-income households. In 2020, EEF funds were used to accomplish the following:

- Installed energy efficiency measures in 163 municipal buildings;
- Weatherized and/or provided weatherization self-install "kits" to 476 income-eligible homes; and
- Worked closely with Community Action Agencies to develop moderate-income program details, outreach methods, and to identify eligible households for targeted outreach.

Chart 16: New Hampshire RGGI Investments by Category



New Hampshire received $176M in proceeds from 2008-2020. RGGI investments represent $18.8M in 2020, and $172M cumulatively.



Program Highlight: Efficiency Programs

For the measures installed in 2020, the Home Energy Assistance and Municipal programs will save approximately 53,712 MWh of electricity and 129,400 MMBtu over the expected life of the energy efficient equipment improvements. Associated bill savings over the lifetime of these improvements is estimated to be $10.5 million. The All-Fuels program will save approximately 23 MWh of electricity and 310 MMBtu over the expected life of the energy efficient equipment improvements made in 2020.

The All-Fuels program was launched in 2016. From 2016 through 2018 the program received $1.2 million of RGGI funding to support energy efficiency measures for retail businesses, and large commercial and industrial energy users. Beginning in 2019, the All-Fuels program supports energy efficiency measures for moderate-income residential energy users with household income of 200% to 300% of Federal Poverty Guidelines. Working with Community Action Agencies, the New Hampshire electric utilities will provide energy audits, and offer financial incentives for installation of energy efficiency measures. Beginning In 2019, this program will receive a total of $690 thousand of RGGI funding over a three-year period.

Success Story: Town of Carroll Public Safety Building and Town Hall

At their 2019 Town Meeting, Carroll voters overwhelmingly approved the proposal for a new Town Hall and Safety Building to be erected at a single, convenient location. The ultimate plan was to construct two separate buildings at the site of the now former, and since removed, town hall. This project presented an ideal opportunity for energy efficiency measures to be incorporated into the new structures through the RGGI-funded NHSaves Municipal Program and partner utility Eversource Energy (“Eversource”). Eversource worked with the project architects and contractors to include multiple energy efficiency measures in the project, resulting in structures that exceed building code efficiency requirements and containing multiple efficient measures, including above code insulation, double glazed windows with argon fill, LED lighting, and efficient heating and water systems.

The town formerly leased a building for its police headquarters and to house its Fire and Rescue departments at another, separate location. With the new 13,000 square foot Safety Building, Carroll is able to house its police and emergency-operations center, and the Twin Mountain Fire and Rescue department, all under one roof. Building spaces include a large apparatus bay, a workshop, fire chief offices, EMS offices, police chief offices, a secure, controlled entry way, evidence rooms, booking/holding areas, a training room, a kitchen, storage, and mechanical/electrical areas. Adjacent to the Safety Building is the new Town Hall, which is a 6,500 square foot structure. Its building spaces include a 1,500 square foot community room, library, historical room, offices/conference rooms, store, and mechanical/electrical areas.

The RGGI-funded NHSaves Municipal program not only allowed the Town of Carroll to construct the buildings they voted for, it also allowed for enhanced versions of the buildings with a more appealing return on investment. These

structures, as built, ensure reduced energy use, carbon emissions and energy bills for the town for many years to come compared to baseline structures that simply meet codes and standards. Together, the buildings are estimated to produce annual savings of 53,591 kWh, 8.0 kW, and 1,493 gallons of propane for the Town of Carroll each year for the useful life of the measures incorporated.

Resources:

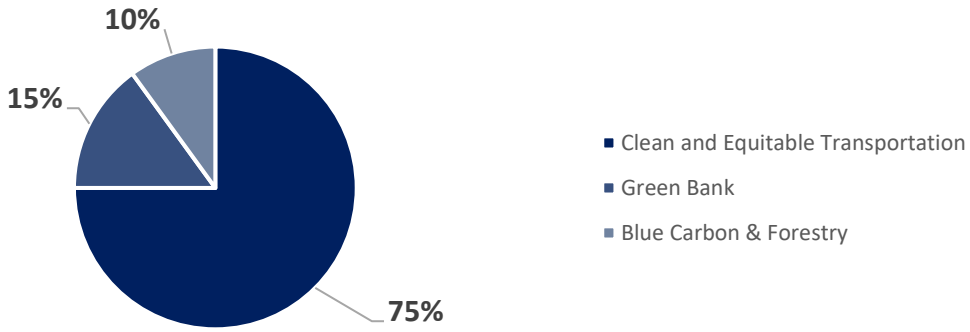
- Energy Efficiency Program Regulatory Webpage
- 2020 Systems Benefit Charge Report to New Hampshire Legislature inc. RGGI Grant Program
- Report to New Hampshire Legislature on 2020 RGGI Program

New Jersey

New Jersey formally rejoined RGGI in 2020, and as part of its onboarding process released its *RGGI Strategic Funding Plan: Years 2020 through 2022*. This plan guides the investment of the state's auction proceeds for its first three years of participation, ensuring cross-agency coordination. By law, New Jersey's RGGI funding is allocated by percentage to three state agencies (60% to the New Jersey Economic Development Authority, 20% to the New Jersey Board of Public Utilities and 20% to the New Jersey Department of Environmental Protection) and each agency is required to spend funds within specific programs areas. The plan identifies cross-agency initiatives that will be funded by RGGI auction proceeds and how these investments complement the state's emissions reductions, clean energy, and environmental justice priorities. Funds from 2020 through 2022 are devoted to programs and projects that fall within the scope of four initiatives:

1. Catalyzing Clean, Equitable Transportation
2. Promoting Blue Carbon in Coastal Habitats
3. Enhancing Forests and Urban Forests
4. Creating a New Jersey Green Bank

Chart 18: New Jersey 2020-2022 Planned RGGI Investments by Category

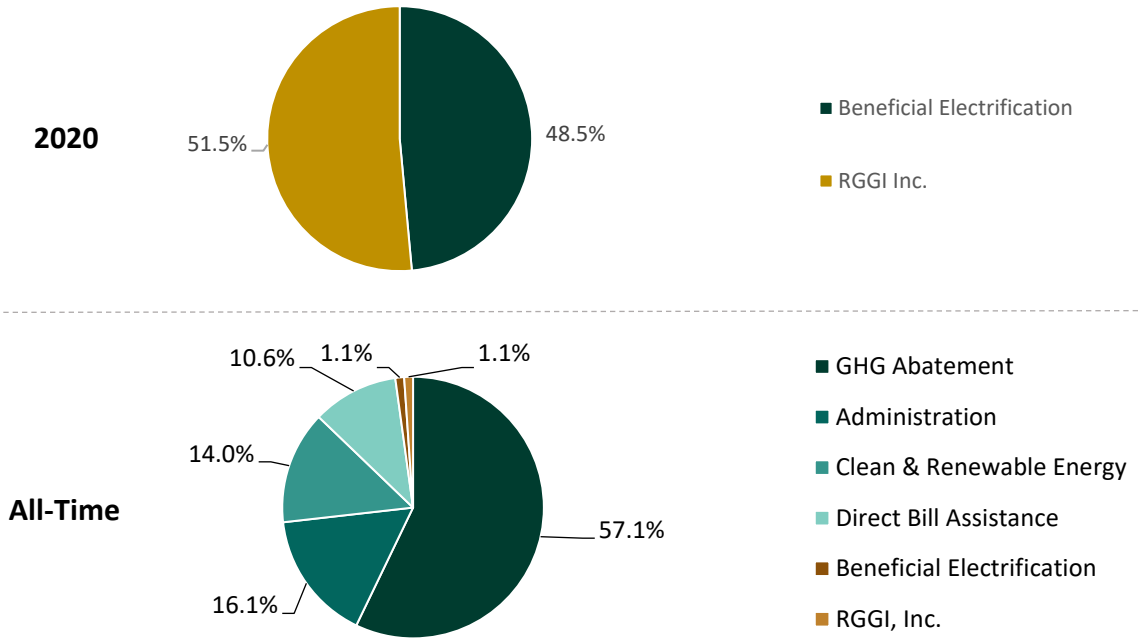


The majority of funding is dedicated to accelerating transportation electrification in the State, focusing on reducing emissions from transportation sources in communities disproportionately impacted by the effects of environmental degradation and climate change. Electrification of the transportation sector is essential for New Jersey to achieve its targets of a 50% reduction in greenhouse gas emissions by 2030 and an 80% reduction by 2050. Currently, transportation accounts for 41% of greenhouse gas emissions in the State, more than twice that of the second largest source, electric generation (19%).[4]

During 2020, the Economic Development Authority, in consultation with, the Board of Public Utilities and the Department of Environmental Protection worked closely with a consultant to develop a zero-emission medium and heavy-duty vehicle strategy, to guide its RGGI investments in clean and equitable transportation.

[4] New Jersey Greenhouse Gas Inventory, Mid-Cycle Update Report. NJ Department of Environmental Protection (NJDEP). 2021. https://www.nj.gov/dep/aqes/ghgarchive/MCU%20GHG%20Inventory_2021.pdf

Chart 19: New Jersey RGGI Investments by Category



New Jersey received $94M in proceeds in 2020. RGGI investments represent $1M in 2020, which are reflected in the 2020 chart above. New Jersey was an early participant in RGGI before withdrawing in 2012, and then resumed participation in 2020. New Jersey's first control period (2008-2012) proceeds investments total $43.6 million, which are included with 2020 investments in the All-Time investments chart.

Program Highlight: Supporting the Transition to Zero-Emission Commercial Transportation

New Jersey is uniquely situated along the Northeast corridor and has extensive transportation assets, including the nation's second busiest port and second densest road and rail network. Electrifying the State's transportation sector therefore requires a thoughtful approach to planning and implementation. To that end, the New Jersey Economic Development Authority, in consultation with the Department of Environmental Protection and the Board of Public Utilities, utilized RGGI funds to develop a strategic approach for establishing New Jersey as a zero-emission transportation hub with a focus on job creation and workforce development. This strategy works in concert with the State's Energy Master Plan and Global Warming Response Act 80x50 Report. As part of this effort, the zero-emission medium and heavy-duty market and supply chain were analyzed, a state strategy was proposed and a slate of new zero-emission medium- and heavy-duty vehicle programs and initiatives were conceptualized. Initial efforts focused on the development of the New Jersey Zero Emission Incentive Program (NJ ZIP), which was formally launched in April of 2021.

NJ ZIP is a voucher program for businesses and organizations purchasing new, electric, class 2b to class 6 vehicles. The program offsets the costs of purchasing electric medium-and heavy-duty vehicles by offering vouchers with base values ranging between $25,000 to $100,000. Additional bonuses are available for small businesses; women-, minority-, and veteran-owned businesses; vehicles that were manufactured in New Jersey; small businesses that scrapped their eligible gas- or diesel-powered medium- and heavy-duty vehicles; and vendors that invest in driver education and training. Funding is limited to companies operating in eligible communities, as defined as the greater Newark and Camden areas for NJ ZIP's inaugural round.

Resources:

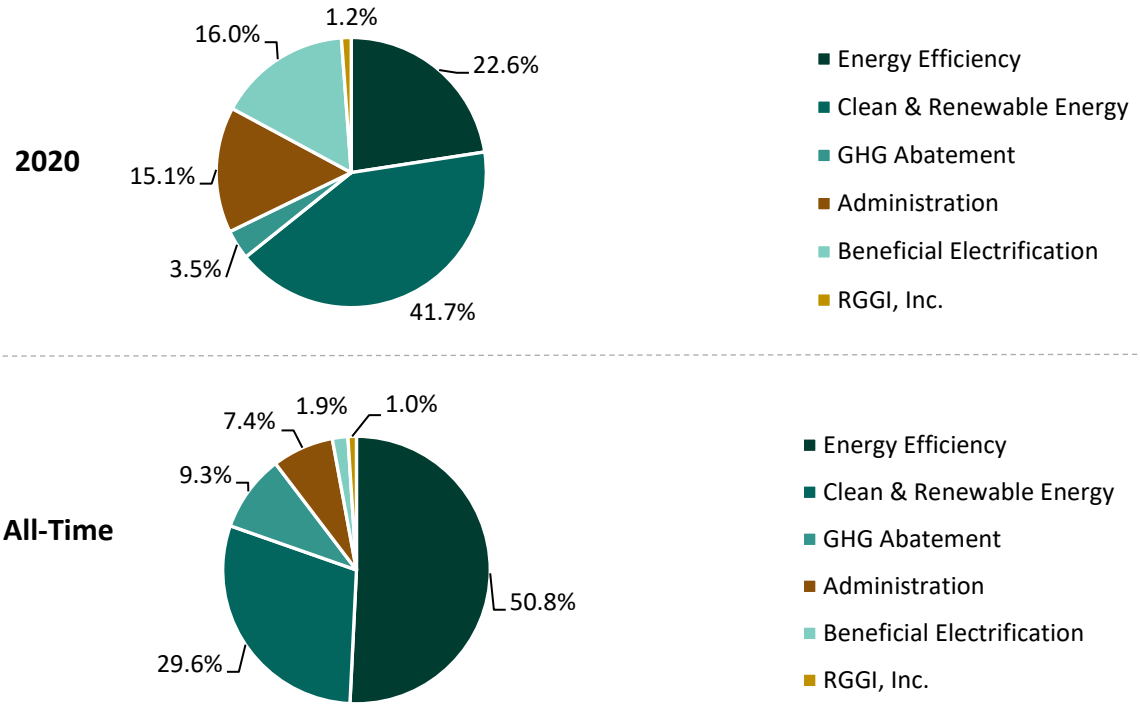
- New Jersey Zero Emission Incentive Program

New York

New York's robust record of climate action includes helping to establish RGGI as North America's first market-based program to reduce carbon emissions. The state affirmed its role as a climate leader with enactment of the Climate Leadership and Community Protection Act, one of the most aggressive climate polices of any major economy. The State has already reduced electricity emissions by 51% since 1990, with a 60% reduction from 2005 to 2019 in greenhouse gas emissions from sources covered by the RGGI program. Further reductions in electricity sector emissions will allow for needed shifts to electrify buildings and transportation. RGGI, alongside state policies such as the Clean Energy Standard, focused on renewable generation deployment, and the ten-year, $5 billion Clean Energy Fund, focused on buildings decarbonization, will continue to serve as a critical tool to reduce state-wide greenhouse gas emissions 40% from 1990 levels by 2030 and realize a zero-carbon electricity sector by 2040.

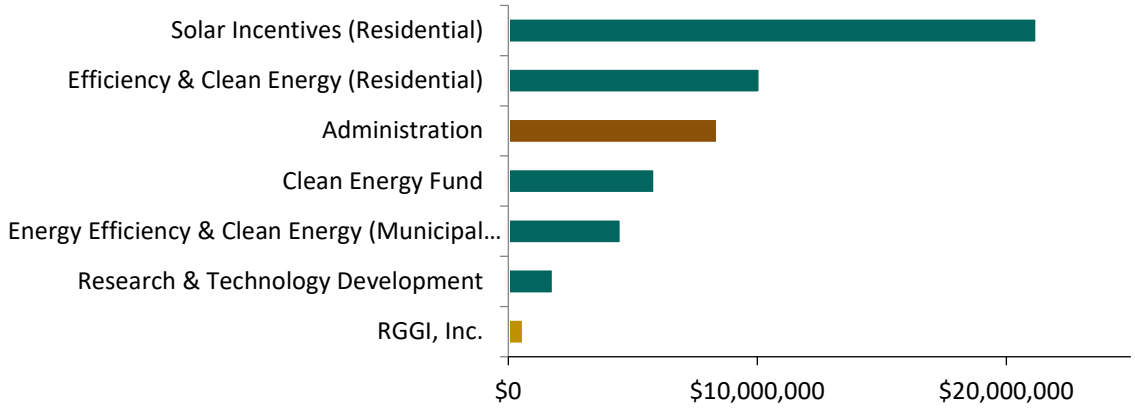
Proceeds generated through RGGI auctions allow New York to pursue opportunities for clean energy, energy efficiency, and carbon reduction that other state activities are not currently designed to reach. The demand for RGGI-supported programs underscores New Yorkers' desire for clean energy opportunities.

Chart 20: New York RGGI Investments by Category



New York received $1.4B in proceeds from 2008-2020. RGGI Investments represent $52.6M in 2020, and $1.1B cumulatively. $345.5M is committed to 2021 and future programs.

Chart 21: 2020 New York RGGI Investments by Recipient



New York RGGI investments represent $ 52.6M in 2020.

Program Highlight: REV Campus Challenge

The Energy to Lead Competition of NYSERDA's REV Campus Challenge initiative challenges colleges and universities across the State to develop and implement plans to advance building decarbonization and innovative, cost-effective clean energy solutions on their campuses and local communities. Institutions are encouraged to incorporate students, curriculum integration, and community engagement into their projects. Proposals with the best solutions to achieve deep energy savings and combat climate change through energy efficiency, renewables, or GHG emission reduction will win approximately $1 million each to help implement their plans. There were three rounds of the Energy to Lead Competition. The final round had proposals submitted in February 2020, and resulted in 18 proposals from 17 institutions. The latest updates from winning institutions of the first two rounds include:

- The State University of New York at Buffalo and its partners are close to finalizing advancement of an offsite solar venture that will enable the university to achieve their goal of 100% renewable purchased electricity. In addition, the university's sustainable living learning lab project, Garden, Relax, or Work (GRoW) Home, has been moved to the North Campus and interior/exterior construction is being finalized. The installation of 22,600 ground mount solar panels commenced in Q4 2020 and is expected to be completed by Q2 2021.
- Bard College filed an application with the Federal Regulatory Commission (FERC) on May 1, 2019 for an exemption from licensing for the Annandale micro hydropower project. FERC requested a stability analysis to also be completed while FERC continues to review the application. Bard College and Micro Hydro have submitted a response to FERC during Q4 2020 and FERC is finalizing their review of the full application package. Since the launch of their Micro Hydro New York website, Bard has released several blog posts about project status and FERC approval on a real-time basis.
- Suffolk County Community College (SCCC) completed the project design and construction documents for their Renewable Energy and STEM Center (RESC) to achieve Net Zero Energy (NZE) in Q3 2020. Following design completion, SCCC obtained a building permit for the RESC and issued an RFP to solicit a general contractor for the building's construction. SCCC selected and awarded a general contractor in Q4 2020 and construction began in Q2 2021.

Success Story: Workforce Development

The Green Jobs Green New York (GJGNY) Workforce Training and Development (WFD) initiative complements other NYSERDA and New York State Department of Labor (DOL) programs targeted at preparing individuals for energy efficiency, solar thermal, and solar electric careers in New York State. WFD programs help to build the State's capacity for long-term carbon reduction, facilitate energy education programs that will help build a clean

energy future, and provide long-term career opportunities for individuals seeking to work in clean energy. Specifically, GJGNY efforts are expanding the State Registered Apprenticeship Program and additional third-party accredited building trades programs by providing clean energy specific content in those training activities. Expectations are to increase access to technical training workshops for skill enhancement and certification. In addition, the GJGNY-supported programs are expected to bridge the gap between training and employment through on-the-job training incentives for businesses seeking to hire and train new workers while reaching out to low-income communities to expand training opportunities. From the program's inception a total of 4,184 New Yorkers were trained in a range of energy efficiency and renewable energy courses.

In 2020, NYSERDA advanced approximately $520,000 in GJGNY WFD funds that will be made available to eligible New York State employers. This program supports wages for new hires on a first-come, first-served basis for eligible clean energy businesses. The program includes higher wage subsidies for employers that hire workers with additional barriers to employment. On Long Island, GJGNY supported 51 total On the Job Training hires in 2019, and a total of 245 total for 2020 – which represents over 480% year-over-year growth in the program to support business hiring, even during the height of the COVID-19 pandemic.

Resources:

- 2020 RGGI Operating Plan
- Regional Greenhouse Gas Initiative (RGGI) Reports - NYSERDA
- GRoW History - UB Sustainability - University at Buffalo
- Blog Landing - Microhydro NY
- Clean Energy Industry reports

Rhode Island

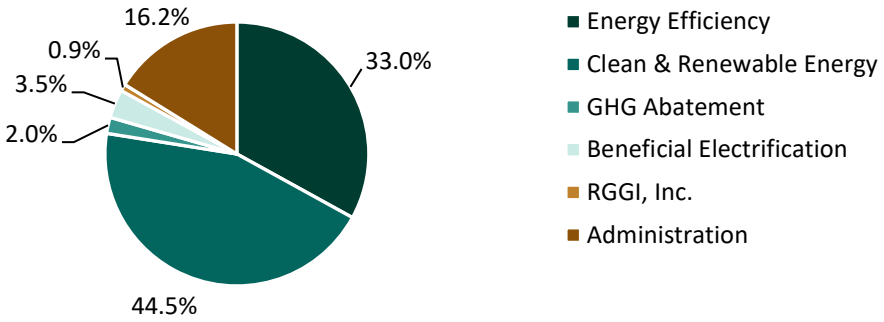
Rhode Island RGGI auction proceeds are allocated by the state's Office of Energy Resources (OER) to drive investment in – and expansion of – clean energy resources, including cost-effective energy efficiency and renewables. In doing so, OER seeks to support investment and job growth in Rhode Island's burgeoning clean energy sector; reduce barriers to consumer adoption of clean energy solutions; place downward pressure on long-term energy costs; and shrink the state's carbon footprint. RGGI auction proceeds are accelerating cleaner, more sustainable energy solutions across public and private sector institutions and in Ocean State communities. These investments are being made in a manner consistent with the Regional Greenhouse Gas Initiative Act, Rhode Island's State Energy Plan, its 2021 Act on Climate, and broader state energy and environmental policy goals.

In 2020, Rhode Island RGGI proceeds were allocated to support several important clean energy programs, including:

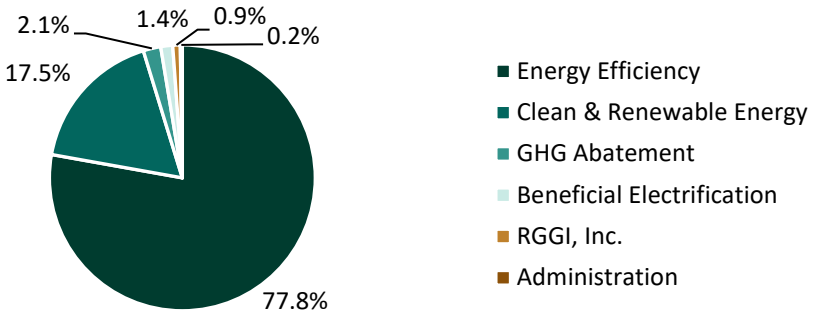
- Providing enhanced financial incentives to support Rhode Island municipalities with the conversion of local streetlights to high-efficiency LED technologies;
- Continued support for the Rhode Island Department of Environmental Management's Energy-Savings Trees program, which distributes trees to homeowners that can be strategically planted on their property and result in saving energy and lower utility bills;
- Advancement of the State Clean Energy Lead by Example program, which is supporting the adoption of energy efficiency and renewable energy projects at state government properties;
- Expanded cost-effective energy efficiency programs and incentives for utility customers located in the Pascoag Utility District;
- Support for the Rhode Island Infrastructure Bank's Efficient Buildings Fund (EBF). RIIB's EBF provides attractive, long-term financing to municipalities and quasi-public agencies for the completion of energy efficiency and renewable energy projects;
- Continued support for a Farm Energy Program that links local farms to energy efficiency and solar PV opportunities;
- Support for the Zero Energy for the Ocean State (ZEOS) program through collaboration with Rhode Island Housing and National Grid. This program is designed to help provide energy savings to low and moderate income (LMI) customers in Rhode Island;
- Support solar development on Brownfields through Rhode Island Commerce Corporation's Renewable Energy Fund; and
- Furthering solar PV adoption by Rhode Island homes and businesses through continued support of the state's Renewable Energy Fund.

Chart 22: Rhode Island RGGI Investments by Category

2020

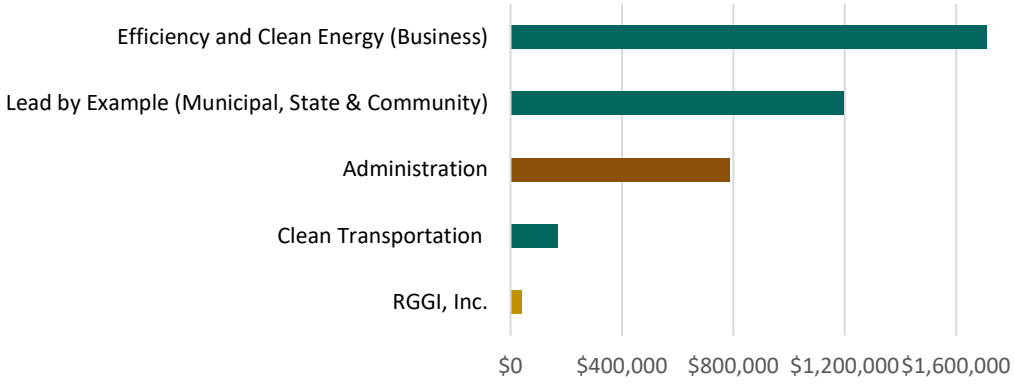


All-Time



Rhode Island received $81.9M in proceeds from 2008-2020. RGGI Investments represent $4.9M in 2020, and $55.7M cumulatively. $26.3M is committed to 2021 and future programs.

Chart 23: 2020 Rhode Island RGGI Investments by Recipient



Rhode Island RGGI investments represent $4.9M in 2020.

Success Story: Pascoag Utility District Battery Storage

The Pascoag Utility District (PUD) is a not-for-profit, quasi-municipal utility serving approximately 5,000 electric customers in the Pascoag and Harrisville sections of Burrillville, Rhode Island.

Their electric service territory is serviced by two feeder lines, one primary and one backup, which were meeting or exceeding maximum capacity during peak load conditions. After comparing options from a system impact study conducted to look for solutions to alleviate these grid concerns, PUD decided to undertake a "non-wires alternative" or NWA project to address this need rather than implement a traditional infrastructure upgrade to both feeder lines.

This NWA solution involved a substation expansion to allow both feeder lines to serve PUD's load simultaneously at peak conditions in combination with a 3 MW/9 MWh battery storage device that will allow PUD to dispatch stored power under contingency conditions or when one of the feeder lines is down.

This project is expected to cost approximately $2.3 million dollars, providing significant savings when compared to the estimated $6-$12 million cost of the traditional infrastructure upgrade. As a not-for-profit utility, maintaining low rates and reliable service are two of PUD's most important priorities, which this NWA solution advanced. In addition, this innovative project will better utilize clean energy resources in the Pascoag territory by charging during off-peak hours and deploy energy during high-load hours to reduce overall load on PUD's system. Having battery storage of this capacity also provides an important resiliency asset to this community that can be deployed during emergency situations or in response to extreme weather conditions to maintain critical services for their customers.

Further showcasing Pascoag Utility District's leadership and creativity was their pursuit of numerous funding channels to support this project. PUD was able to secure financing for some of the project costs through the Rhode Island Infrastructure Bank at well-below market interest rates while bringing on a strong institutional partner to support this project.

This project began construction in 2021 and is expected to be fully complete, interconnected, and operational in 2022 prior to the summer peak season. Once operational, it is anticipated that this clean energy project will deliver over 80 tons of CO2 reductions annually and provide significant reliability and grid optimization services to the community as well.

This project was funded with RGGI Proceeds.

Resources:

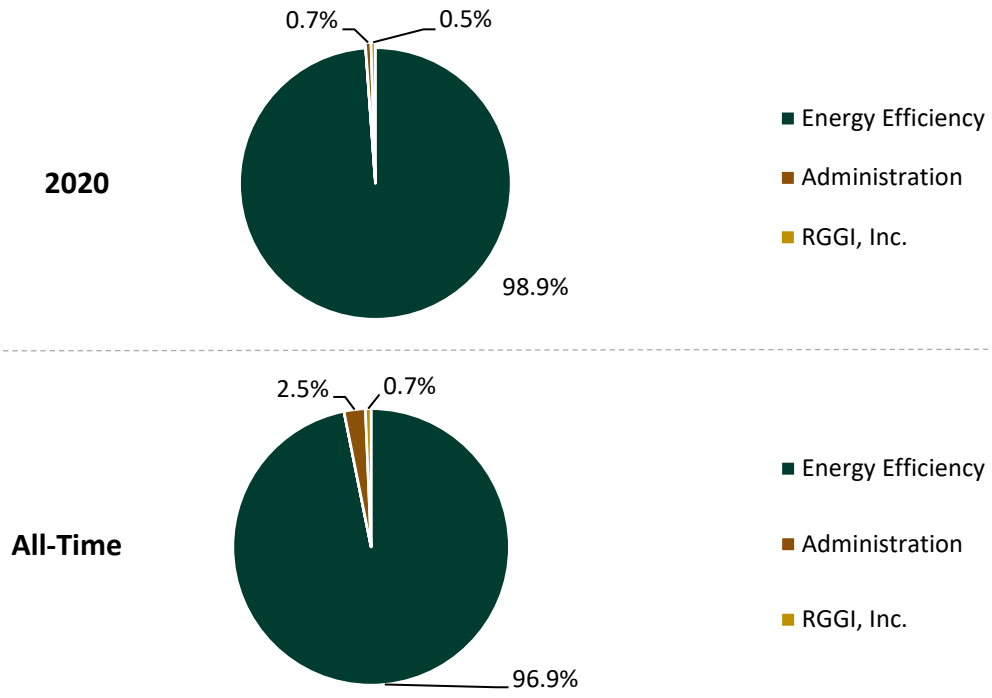
- Regional Greenhouse Gas Initiative (RGGI)- Rhode Island -Office of Energy Resources (ri.gov)

Vermont

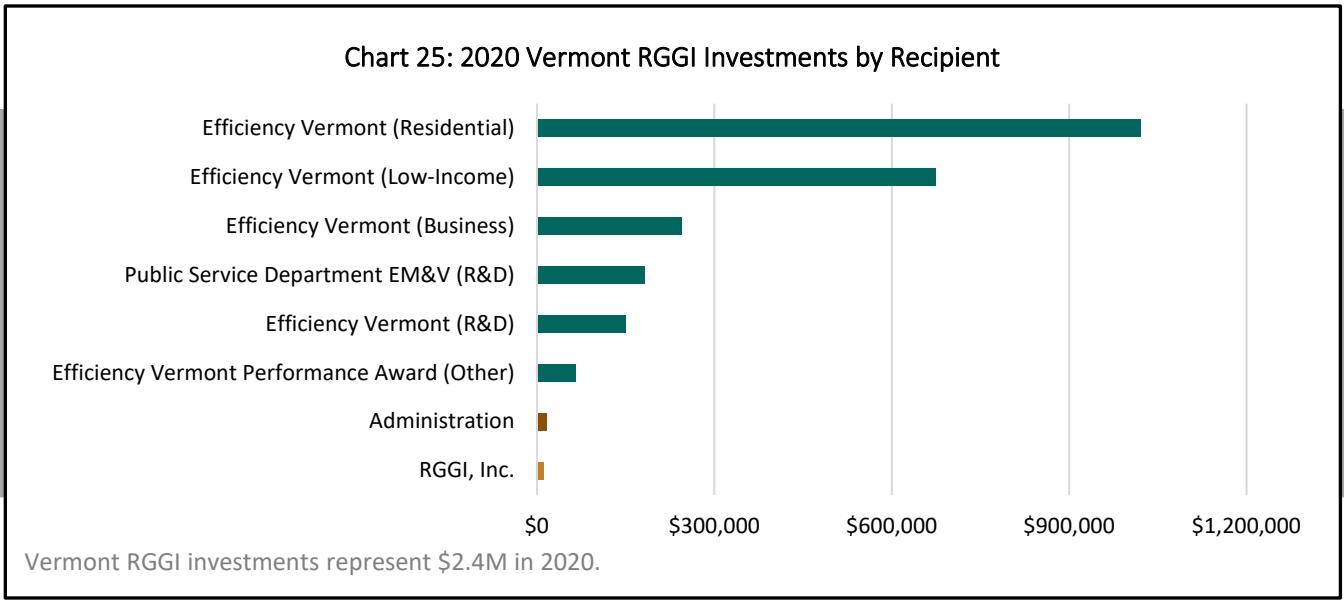
Vermont invests the majority of its CO_2 allowance proceeds in programs managed by Efficiency Vermont. RGGI funds allow Efficiency Vermont to expand its electrical energy efficiency programs to include thermal energy and process fuels efficiency programs. Efficiency Vermont's participation in the regional grid's forward capacity market also provides funds for this program expansion. Vermont's thermal energy and process fuels efficiency programs funded by RGGI through 2020 are estimated to result in lifetime energy savings of 4,672,229 MMBtu. These programs are estimated to avoid the emission of 278,837 short tons of CO_2, and to save participants $113,109,031 on their energy bills over the lifetime of those investments. Vermont's RGGI-funded programs have served approximately 12,326 households and 689 businesses. Programs currently supported by CO_2 allowance proceeds include the Home Performance with ENERGY STAR® service for residential customers, the Building Performance service providing incentives for efficiency services to small business customers, the Home Energy Loan for residential customers, low-income energy efficiency services through 3E Thermal project management, custom commercial thermal efficiency projects, and technologies including woodstoves and heat pumps.

Efficiency Vermont, the nation's first ratepayer-funded energy efficiency utility, is overseen by the Vermont Public Utility Commission, and implemented by VEIC. Efficiency Vermont's programs have a proven track record of saving energy and money for commercial, industrial, and residential consumers. These and other energy efficiency programs helped to rank Vermont third in the nation in 2020, according to the American Council for an Energy Efficient Economy (A CEEE) State Energy Efficiency Scorecard.

Chart 24: Vermont RGGI Investments by Category



Vermont received $28.2M in proceeds from 2008-2020. Vermont investments represent $25.8M cumulatively. In 2020, Vermont received $2.5M in proceeds, $176k of which is committed to 2021 and future programs.



Program Highlight: Home Performance with ENERGY STAR and Home Energy Loan

The Efficiency Vermont Home Performance with ENERGY STAR service is an incentive-based program for single-family Vermont residences to lower utility bills and increase home comfort and safety by installing insulation, air sealing, and ventilation (heating systems improvements are also recommended). Vermonters can access comprehensive thermal efficiency retrofits, incentives to offset project costs, and low-no interest rate financing. Customers hire a participating Efficiency Excellence Network, Building Performance Institute certified, contractor. This allows customers to receive incentives up to $5,500, requires the contractor to meet Vermont residential building energy codes and standards, health and safety and program requirements, and provides quality assurance for projects.

The Efficiency Vermont Home Performance with ENERGY STAR service officially launched in 2005. In 2008, when the Vermont Legislature set a statewide goal to weatherize 80,000 homes by the year 2020, the Home Performance with ENERGY STAR service was galvanized. The legislation sought to harness energy efficiency as a driver of savings for consumers and economic development in Vermont. Home Performance with ENERGY STAR is one of the primary programs contributing to these goals.

Home Performance with ENERGY STAR is a national brand managed by the U.S. Department of Energy (U.S. DOE). Across the US, 50 organizations sponsor local programs under this brand. Although local programs differ, they follow the same basic structure to ensure a comprehensive, whole-house approach to energy efficiency and maximize long-term savings for homeowners. The key components of the Home Performance with ENERGY STAR program approach are outlined by U.S. DOE and implemented in Vermont by Efficiency Vermont.

The RGGI funded portion of the Efficiency Vermont Home Energy Loan program provides residential customers financing for Home Performance with ENERGY STAR projects and other thermal efficiency projects, including woodstoves (pellet and cord wood), and central pellet heating systems with income-based interest-rate buydowns and loan loss reserve support for participating lenders.

Success Story: RGGI Funds Help VT Accelerate Moderate-Income Weatherization Support

Efficiency Vermont helps Vermonters who don't qualify for low-income assistance weatherize their homes by providing rebates that offset the project costs. A substantial portion of the funding for these incentives has come from RGGI revenues, which have helped Efficiency Vermont build its robust Home Performance with ENERGY STAR program.

Leading up to 2020, Efficiency Vermont was able to support between 800-1,100 households each year through the Home Performance with ENERGY STAR program. This strong annual participation allowed the weatherization market to develop over time and positioned the state to make significant enhancement when the opportunity presented itself.

Such an opportunity came in 2019, when the legislature passed, and Governor Scott enacted, Act 62, allowing Efficiency Vermont to repurpose existing budget dollars from its electric energy efficiency budget as a result of operational efficiency cost savings, to help more moderate-income Vermonters weatherize their homes. With a strong Home Performance with ENERGY STAR program already well established, thanks in part to the sustained investment of RGGI funds over time, Efficiency Vermont was able to rapidly deploy these funds as increased incentives for moderate income Vermonters in 2020.

Efficiency Vermont reinvigorated and expanded the existing weatherization offer to provide up to 75% off project costs, with 0% interest financing for 60 months, and the first six months of payments would be paid for by Efficiency Vermont. It was paired with a robust, multimedia campaign.

The impact was immediate. Once the cost came down through the upfront incentive, and homeowners could break the remaining cost into low monthly payments (about $50 a month), the demand for weatherization surged statewide.

Steve Dunn, Program Manager for the DOE Home Performance with ENERGY STAR program, said that Efficiency Vermont is leading the effort to improve energy efficiency in homes, which lowers energy costs and improves home comfort and safety for thousands of families across the state, including communities that are not able to afford the cost of energy efficiency improvements.

Jill Neitlich and husband Flynn of Wardsboro, VT joined thousands of other Vermonters in 2020 by taking advantage of weatherization incentives through Efficiency Vermont's Home Performance with ENERGY STAR program.

"By providing low-moderate income families access to weatherization programs, Efficiency Vermont has made sure that the energy savings and health benefits of weatherization improvements are available to the families who need it most," said Dunn.

Thanks to consistent funding for more than a decade through RGGI and other revenues, Efficiency Vermont was able to tap into a proven, fully developed Home Performance with ENERGY STAR program in 2020 to ramp up the program and extend its reach to thousands of Vermonters who most needed it.

As the Vermont Public Utility Commission stated in its Act 62 Final Report to the legislature, "Efficiency Vermont was able to quadruple the number of projects it completed by reducing up-front project costs. In August and September 2020, increased funding allowed Efficiency Vermont to complete four to five times the number of projects historically completed in those months."

Weatherization directly supports Vermonters, boosts a growing workforce, and reduces greenhouse gas emissions. The past decade has proved that our statewide system of delivering these benefits has been effective. 2020 proved that without a stable, long-term source of additional funding like RGGI, Vermont would have missed out on the opportunity to help thousands more Vermonters. Efficiency Vermont looks forward to continuing its successful partnerships to serve Vermonters and support our state's goals for many years to come.

Resources:

- Efficiency Vermont Rebates
- Efficiency Vermont Services
- Efficiency Vermont News

Glossary and Methodology

Program Categories

Administration
Funds directed to administrative overhead expense associated with all RGGI-funded programs, including outsourced and in-house overhead expenses.

Beneficial Electrification
Programs designed to reduce fossil fuel consumption by implementing or facilitating fuel-switching to replace direct fossil fuel use with electric power. Examples include incentives for electric vehicles and home appliances, and installation of electric vehicle infrastructure. Program costs include evaluation and measurement.

Clean and Renewable Energy
Programs directed at accelerating the deployment of renewable or other non-carbon emitting energy technologies. Program costs include evaluation and measurement. Examples include incentives for residential solar panels, financing of commercial renewable energy projects through green banking, research and development of new energy technologies.

Direct Bill Assistance
Programs providing energy bill payment assistance, including direct bill assistance to low-income ratepayers. Program costs include evaluation and measurement.

Energy Efficiency
Programs designed to improve energy efficiency by reducing overall energy use without degrading functionality. This includes programs directed at assisting low-income families and small businesses. Program costs include evaluation and measurement. Examples: home energy audit programs, home and building weatherization, energy efficient appliance or industrial equipment rebate programs, compact fluorescent light bulb programs, and energy efficiency workforce training programs.

Greenhouse Gas Abatement
Programs promoting the research and development of advanced energy technologies, the reduction of vehicle miles traveled, the reduction of emissions in the power generation sector, tree-planting projects designed to increase carbon sequestration, and other initiatives to reduce greenhouse gases. Program costs include evaluation and measurement.

RGGI, Inc.
Funds provided to RGGI, Inc. to support and implement state CO_2 Budget Trading programs.

General Terms

RGGI Investments
RGGI Investments are the proceeds generated by RGGI CO_2 allowance auctions that have been invested by the RGGI states in the energy efficiency, clean and renewable energy, GHG abatement, and direct bill assistance programs discussed in this report.

Future Committed
Future committed funds are the proceeds generated by RGGI CO_2 allowance auctions that have not yet been invested by the RGGI states. Future committed proceeds represent funds that could be invested by the state in 2020 and beyond.

Current Period
The twelve-month period covered by this report, which may be either the fiscal year or calendar year 2020, as defined by each state.

Benefits and Statistics

Annual (2020)
A measure of one year's worth of benefits from all measures installed in 2020. Note that actual realized benefits in the year 2020 may differ slightly from the 2020 annual benefits, since measures may be installed at different times during the year.

Lifetime (2020)
The full benefits of measures installed in 2020, including benefits to be realized in the future. The lifespan of installed measures varies by type of measure and by program, and is calculated and provided by program administrators. For example, an industrial boiler would likely be estimated to provide benefits over a longer lifespan than an LED lightbulb. Measure lifespans used in this report typically range between 5-25 years.

Lifetime (All-Time)
The total estimated lifetime benefits of all measures installed since the inception of the RGGI program. This includes the full lifetime benefits of measures installed in previous years, in addition to the lifetime benefits of 2020 measures.

Funds Invested
Total dollar amount of RGGI proceeds invested in a program or category over a given period. For programs that are partially funded by RGGI, only the amount provided by RGGI funds is included.

Participating Households: Programs
Number of households that have directly received assistance as a result of each program (e.g. number of homes weatherized, number of households receiving home energy audits, etc.). Households participating in more than one program may be counted under each program they have participated in (e.g. a completed home energy audit constitutes a participating household even if the household may elect to further participate in programs to install recommended measures). For multi-family dwellings, each unit within the multi-family home may be considered to be a household. For retail programs such as lightbulb distribution, households may be extrapolated from the number of items distributed.

Participating Households: Direct Bill Assistance
Number of households receiving direct bill assistance or energy bill rebates funded through RGGI proceeds. Bill assistance programs vary by state; in some cases rebates may be returned to all customers, while in other cases they may be targeted to low-income customers or to specific customer types.

Participating Businesses: Programs
Number of "end-user" businesses who have directly received assistance as a result of the program (e.g. number of businesses whose offices were weatherized, number of businesses receiving grant assistance to install energy efficiency measures, etc… via a grant, loan, or rebate). Businesses participating in more than one program will be counted under each program they have participated in (e.g. a completed audit constitutes a Participating Business even if the business may elect to further participate in programs to install recommended measures).

Participating Businesses: Direct Bill Assistance
Number of businesses receiving direct bill assistance or energy bill rebates funded through RGGI proceeds.

Increased Employment
Total estimated job-years created as a result of RGGI funds invested, estimated on a regional basis based on literature review.

MWh Avoided
Estimated total MWh projected to be avoided as a result of RGGI funds invested, calculated using program-specific savings as defined by each state.

MMBtu Avoided
Estimated total MMBtu projected to be avoided as a result of RGGI funds invested, calculated using program-specific savings as defined by each state.

Energy Bill Savings
Estimated gross amount saved as a result of RGGI funds invested (initial investment in installed measures is not deducted). Calculated using program-specific savings, as defined by each state. Estimates of lifetime energy bill savings are given in current year dollars as of the start of the savings, and in most cases are not discounted into the future. Where discounts are applied, they are noted on state-specific pages.

CO_2 Emissions Avoided
Estimated total number of short tons of CO_2 avoided as a result of funds invested, calculated using a program-specific formula as defined by each state.

RGGI States Proceeds Contacts

Connecticut
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Department of Energy & Environmental Protection

Dino Pascua
Department of Energy & Environmental Protection

Delaware
Athena Bi
Delaware Sustainable Energy Utility

Annina Northridge
Department of Natural Resources & Environmental Control

Maine
Laura Martel
Efficiency Maine

Emily Cushman
Efficiency Maine

Lauren Trapani
Efficiency Maine

John Brautigam
Maine Public Utilities Commission

Maryland
Ryan Opsal
Maryland Energy Administration

Chris Hoagland
Department of the Environment

Massachusetts
Paul Lopes
Department of Energy Resources

New Hampshire
Josh Elliott
Department of Energy

New Jersey
Robert Kettig
Department of Environmental Protection

Helaine Barr
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New York
Cory Wydysh
NYSERDA

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Office of Energy Resources

Vermont
Mary-Jo Krolewski
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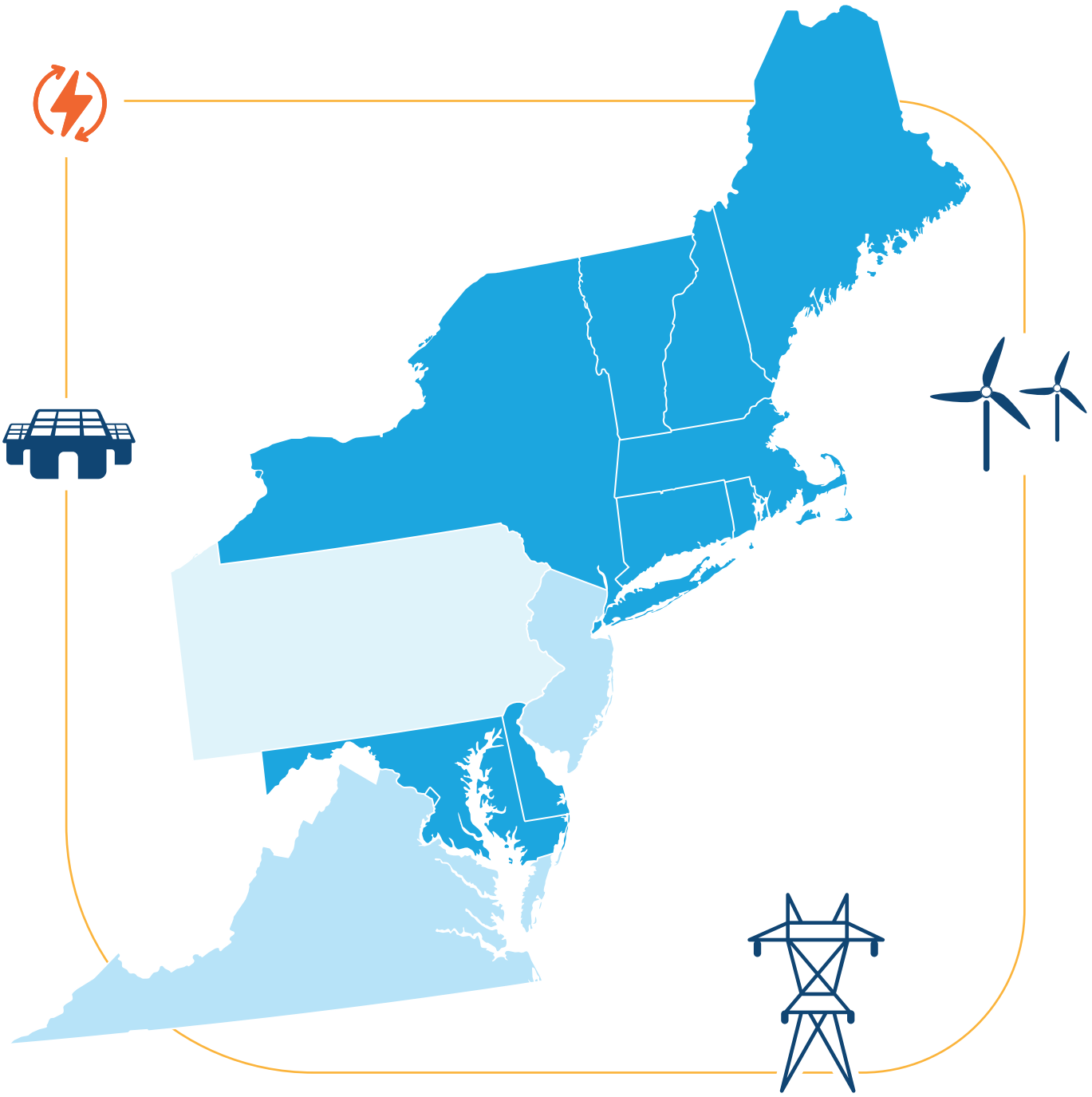
Matthew Walker
Vermont Energy Investment Corp.

David Westman
Vermont Energy Investment Corp.

Attachment 39

The Regional Greenhouse Gas Initiative

10 Years in Review



2019

Acadia Center

Executive Summary

Through ten years of operation, the Regional Greenhouse Gas Initiative (RGGI) has helped Northeast and Mid-Atlantic states[1] achieve significant reductions in emissions of carbon dioxide (CO_2) and other pollutants from the electric power sector. The country's first program designed to reduce climate change-causing pollution from power plants has provided a wealth of lessons to be incorporated into the next generation of climate policies, from successes to build on to opportunities for improvement.

The participating states have experienced substantial benefits from RGGI since 2008, the year before the program launched. Concerns that climate policy would make states less competitive have been directly refuted by RGGI's experience: the RGGI program is helping participating states outperform the rest of the country. Since 2008:

- **CO_2 emissions from RGGI power plants have fallen by 47%,** outpacing the rest of the country by 90%;
- **Electricity prices in RGGI states have fallen by 5.7%**, while prices have *increased* in the rest of the country by 8.6%;
- **GDP of the RGGI states has grown by 47%**, outpacing growth in rest of the country by 31%;
- **RGGI states have generated $3.2 billion in allowance auction proceeds**,[i] the majority of which have been invested in energy efficiency and renewable energy programs; and
- **RGGI-driven reductions in co-pollutant emissions have resulted in over $5.7 billion in health and productivity benefits.**[ii]

Much has changed since RGGI was launched, beyond the climate, economic and health improvements described above. Most notably, climate policy has advanced by leaps and bounds. When RGGI was implemented, it was just the second program in the world to regulate carbon emissions, and the first to require polluters to pay for emissions allowances (permits to emit pollution). Now, there are 57 national or subnational carbon pricing programs in place,[iii] many of them drawing on lessons learned from RGGI.

At the same time, findings from the scientific community have made the urgency of climate action increasingly hard to ignore. If the planet is to avoid crossing the 1.5 degree warming threshold, global annual GHG emissions need to be reduced by 45% from 2010 levels by 2030.[iv] To make a meaningful difference in reducing the catastrophic costs of climate change, we need urgent action.

Finally, sound climate policy needs to be oriented around climate justice. Programs designed to reduce GHG emissions must be good for the planet and for communities. In the RGGI context, that means improving air quality in environmental justice communities, ensuring that underserved populations have access to RGGI-funded energy efficiency and clean energy programs, and importantly, that those communities have a say in shaping the policy.[v] While there is much more to do to protect vulnerable communities from power plant pollution, states must also act with urgency to reduce locally-harmful pollution from other sources, most notably transportation.

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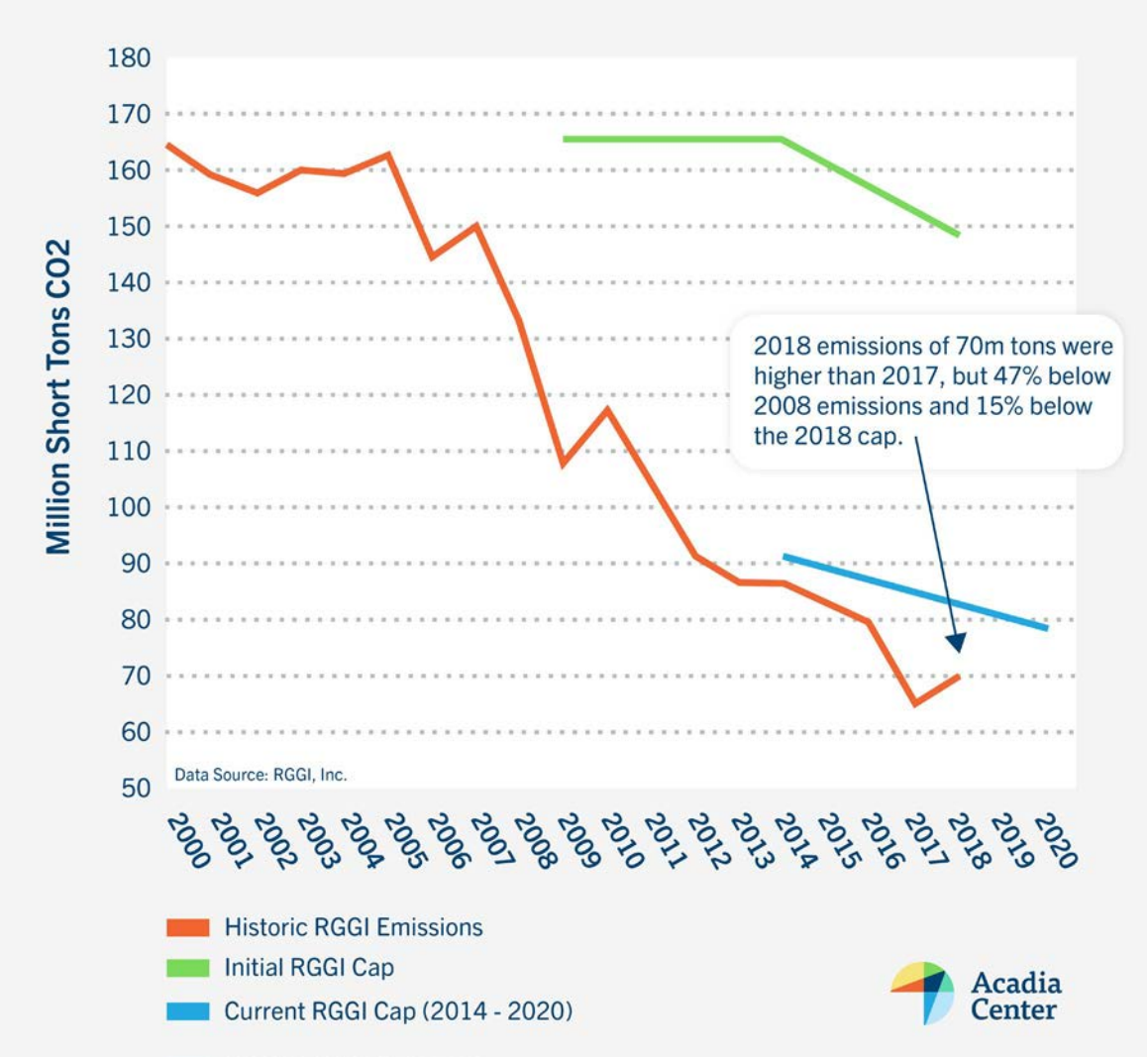
[1] Analysis in this report covers the currently participating RGGI states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. [*Footnotes elaborate on points within this report, whereas endnotes cite references and provide detailed analytic methodologies where relevant.*]

Emissions Trends and RGGI Cap Dynamics

Rapid CO_2 Reductions Outpace the Rest of the Country

States participating in RGGI have seen a steep decline in CO_2 emissions from power plants over the last 10 years. Since 2008, the year before the program launched, RGGI emissions have fallen from 133 million short tons of CO_2 to 70 million tons in 2018, shown in Figure 1. The impressive electric sector emission reductions achieved in RGGI states over that time period have outpaced reductions in the rest of the country by a staggering 90%. While the RGGI program has not been the sole factor behind the region's rapid electric sector decarbonization, earlier analysis shows that it has been a key driver—and accelerator—of emission reductions from power plants.[vi]

Figure 1: RGGI Cap and Historic Emissions – Nine RGGI States



As Figure 2 shows, rapidly declining RGGI emissions and an oversupply of allowances have kept RGGI allowance prices relatively low. From Auctions 8 to 18, RGGI allowances sold at the reserve price—the lowest price at which allowances can be sold through auction—and the highest RGGI auction clearing price since the program launched was $7.50 per allowance. For comparison, the 2019 auction reserve price in California and Quebec's cap-and-invest program is $15.62 per allowance.[vii] This higher reserve price provides a greater incentive to pursue additional CO_2 abatement measures.

Figure 2: Quarterly RGGI Emissions and Auction Clearing Prices

Aligning the RGGI Cap with Current Emissions and the Climate Crisis

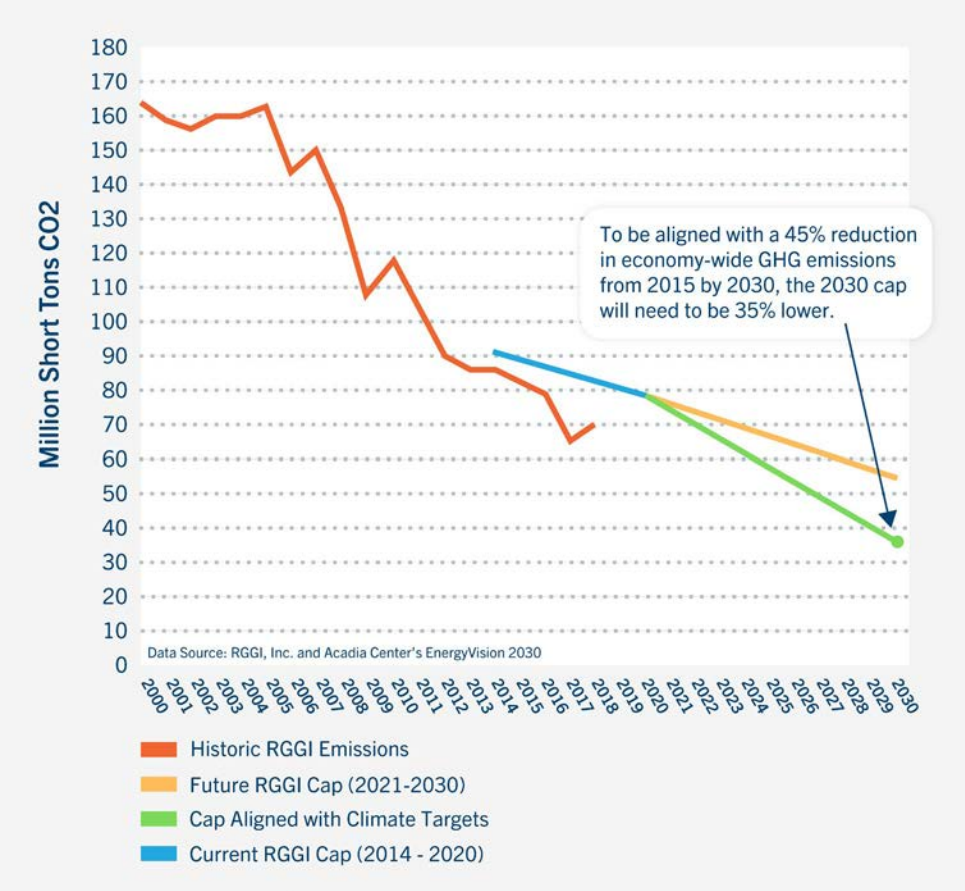
Through the first half of 2019 it appears the trend of declining RGGI emissions will continue, with RGGI COATS[viii] data showing the lowest first-half emissions in the program's history (see Figure 2).[ix] The fact that RGGI emissions have been well below the RGGI cap in every year of the program's history, as shown in Figure 1, is good for the climate and encouraging for future decarbonization efforts, but it also highlights the need for certain program reforms.

Chief among these reforms is a more stringent cap on emissions. In 2017, at the conclusion of the latest RGGI Program Review, the RGGI states committed to a new cap from 2021-2030 with a slightly faster emission reduction trajectory than the cap in place from 2014-2020. The extension of the cap and the increased ambition are positive steps, and the 2030 cap level of 54.7 million short tons commits the region to a 30% reduction in electric sector CO_2 emissions beyond the 2020 requirement. In addition to the lower cap, the Program Review resulted in measures that will strengthen the program by constraining RGGI allowance supply and limiting future emissions.[x] A third adjustment for banked allowances will eliminate the allowance surplus accrued through 2020, higher Cost Containment Reserve (CCR) price triggers will help avoid unnecessary increases in allowance supply, and the innovative Emissions Containment Reserve (ECR) will help the RGGI states secure additional, low-cost emission reductions.[xi]

Despite these measures to strengthen the program, a more ambitious RGGI cap is necessary. 2018 emissions are already well below the new, more ambitious cap set for 2021. In fact, 2018 emissions are already below the cap level set for 2023. To be most effective, the RGGI cap needs to more closely reflect the new, lower-carbon reality of the region's electric sector and the science-based GHG reduction targets adopted by the RGGI states.

The region's electric sector CO_2 emissions will need to be far below the 2030 cap if the region is to achieve its economy-wide GHG reduction goals. Acadia Center's EnergyVision 2030[xii] finds that for the Northeast states to achieve a 45% reduction in economy-wide GHG emissions by 2030 (from 2015 levels), the region would need to achieve a 57% reduction in electric sector GHG emissions by 2030 (compared to a 20% reduction from transportation and 30% reduction from buildings). As shown in Figure 3, if that 57% reduction from 2015 were applied to the RGGI cap, it would yield a 2030 cap of 35.8 million short tons: a 35% lower RGGI cap than what the states have agreed to. This more ambitious electric sector decarbonization will make it possible for the region to achieve greater emission reductions through the electrification of other sectors.

Figure 3: Aligning the Future RGGI Cap with Climate Targets



Of course, achieving economy-wide climate targets will require significant action to reduce GHG emissions from all sectors. There are critical carbon pricing policies currently in development or under consideration that, if implemented, will steer the region in the right direction. At the state level, momentum is building around carbon pricing bills that would establish a price on CO_2 emissions from sectors not covered by RGGI. Across the region, the 12 states of the Transportation & Climate Initiative (TCI) are developing a multi-state cap-and-invest program to reduce CO_2 emissions from the transportation sector.[xiii] Both of those policies can build on the best of the RGGI model, but in order to be most effective, they will depend on a decarbonized electric sector.

Economic Trends and Electricity Prices

RGGI's Economic Impacts

RGGI has generated significant economic benefits for states participating in the program. By selling allowances, RGGI states raise revenue to reinvest in energy efficiency, renewable energy, and other consumer programs that increase economic activity in participating states. The majority of program revenue (58% through 2016[xiv]) has been invested in energy efficiency programs that reduce consumers' bills and reduce demand for power. Lower power demand resulting from energy efficiency means fewer emissions from power plants, and less money leaving the region to pay for imported fossil fuels. Energy bill savings increase consumer spending, benefiting businesses that offer goods and services in the region. According to independent macroeconomic analysis of

RGGI through 2017, **the program has created over $4 billion in net economic gains and over 44,000 job-years of employment.**[xv]

Economic Growth and Emissions

The RGGI states have managed to rapidly reduce CO_2 emissions without impeding economic growth. In fact, the region has proven that decarbonization and economic growth can go hand in hand. While the country as a whole has been experiencing declining CO_2 emissions and economic growth, the RGGI states have seen faster economic growth and steeper CO_2 reductions. As shown in Figure 4, from 2008 (before RGGI's launch) to 2018, **RGGI states' economies grew by 46.9% versus 35.8% in states that do not regulate or put a price on carbon emissions** (this group of 40 states, referred to below as the "rest of the country", does not include California, which has similarly outpaced national growth since capping carbon emissions[xvi]). Over the same 2008 to 2018 period, **emissions in the RGGI region dropped by 46% versus 24% in the rest of the country**.[xvii]

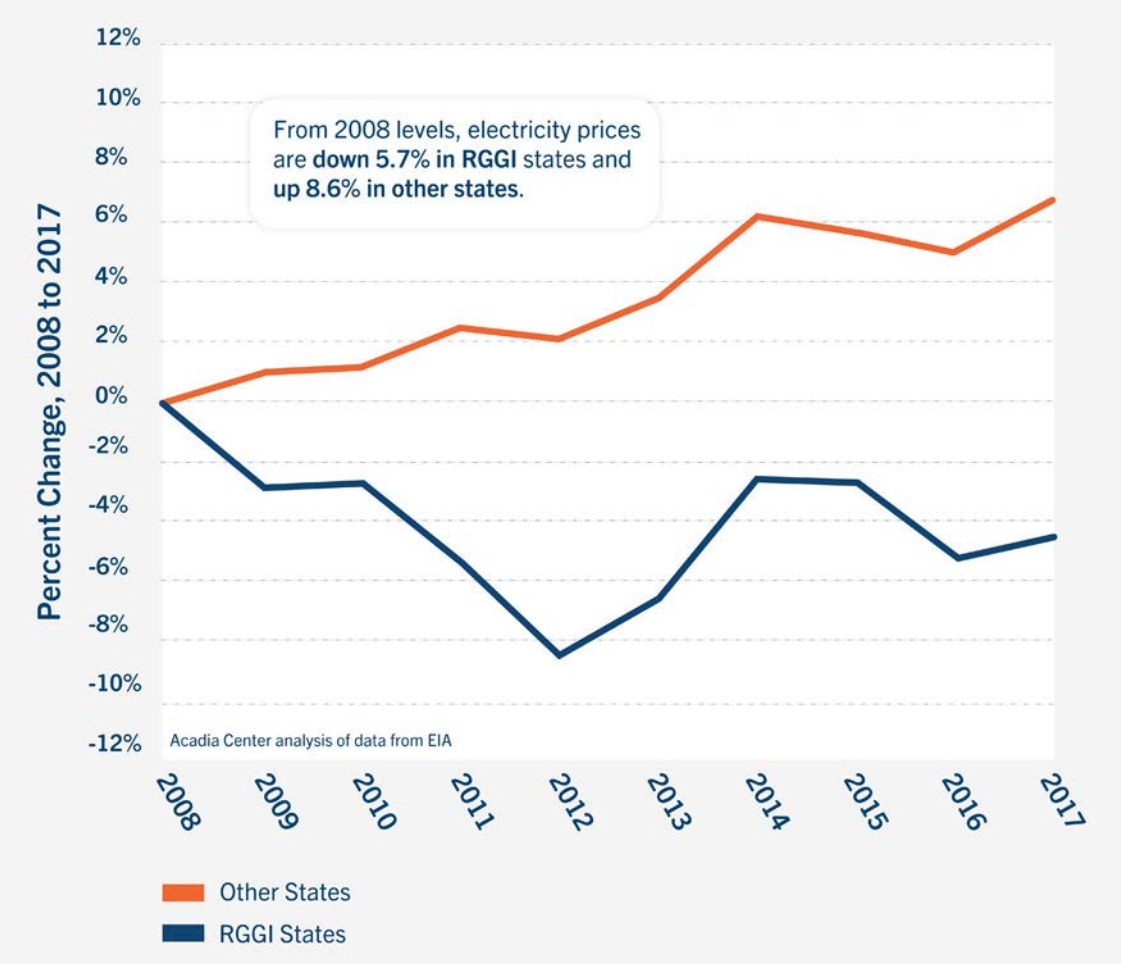
Figure 4: Change in Economic Growth and Emissions, 2008 to 2018

Electricity demand has historically been tied to economic growth, with electricity consumption and related emissions increasing during periods of economic expansion and decreasing in economic downturns. This correlation has been broken in the RGGI region, a new reality that appears to be mirrored—though slightly less dramatically—at the national level. A decade of RGGI and decarbonization of the electric power sector demonstrates that emissions reductions can be achieved as the economy grows.

Electricity Prices

Average retail electricity prices in the region have decreased since RGGI took effect. Comparing retail electricity prices from 2008 to 2017 shows that prices have dropped by 5.7% across the region.[xviii] While RGGI's direct impact on electricity prices is difficult to isolate from other factors, it is evident that the program has not caused electricity prices to rise from 2008 levels, in part due to RGGI-funded investments in energy efficiency. Concerns that climate policy will make states less competitive are directly refuted by RGGI's experience: RGGI states are faring much better than the rest of the country on electricity price trends. As shown in Figure 5, while RGGI's electricity prices have fallen from where they were in 2008, the rest of the country[2] has experienced an 8.6% increase in retail electricity prices over the same period.

Figure 5: Volume-Weighted Electricity Prices, 2008 to 2017



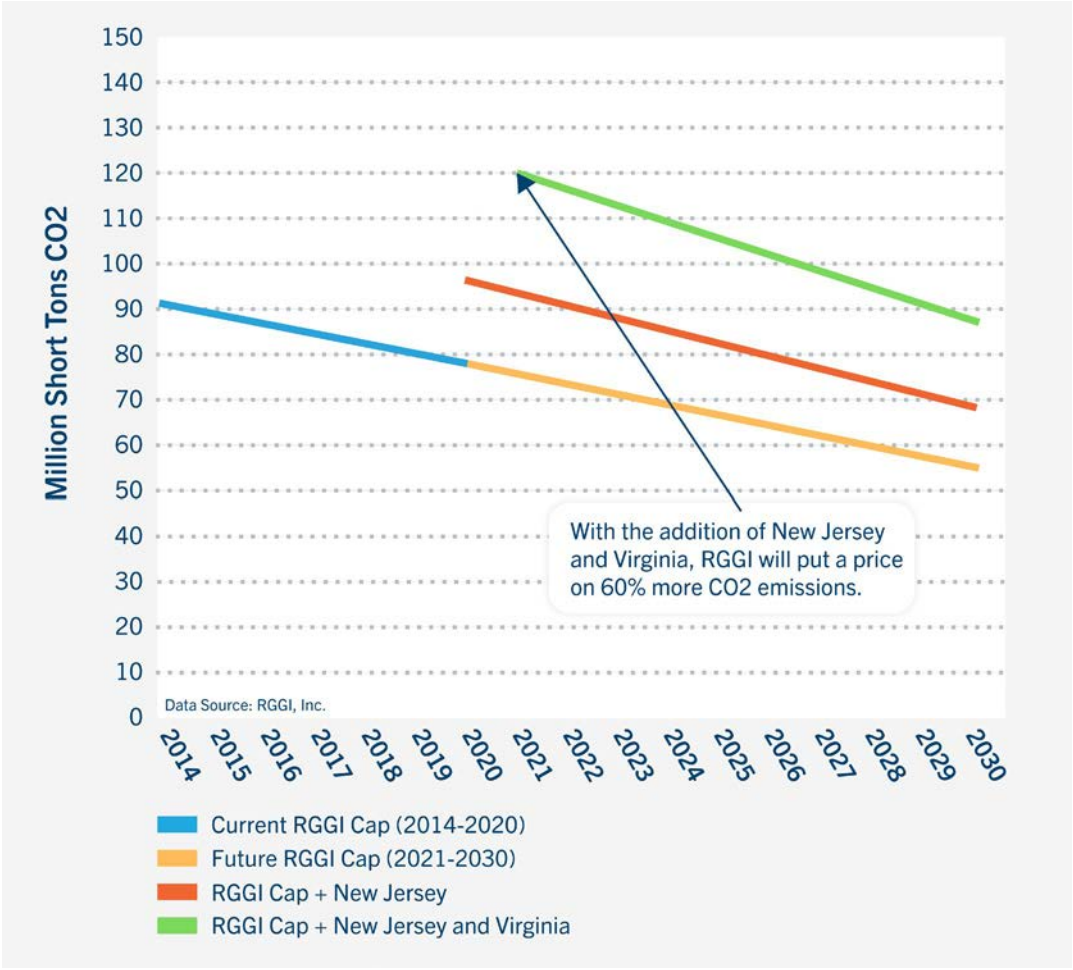
[2] The "rest of the country" excludes California, which, like the RGGI states, has implemented a cap-and-invest program to reduce CO_2 emissions.

Welcoming Additional States

There are currently nine states participating in the RGGI market, but that number is poised to grow to 11 by 2021. New Jersey is set to be the first addition, with the New Jersey Department of Environmental Protection adopting regulations in the summer of 2019 to rejoin the RGGI program on January 1st, 2020.[xix] This will mark New Jersey's return to the program, as the state participated in RGGI as a founding member until then-Governor Christie removed the state from the program in 2011. It appears likely that Virginia will follow New Jersey, with regulations approved to participate in a carbon trading program linked with the RGGI market.[xx] Virginia's participation in the RGGI market is expected to begin on January 1st, 2021.

Regulations in both New Jersey and Virginia would implement state CO_2 emission budgets aligned with the 2020-2030 RGGI cap, requiring a 30% reduction in region-wide emissions over that time period. The addition of these two states to the program will represent a substantial expansion, both in terms of CO_2 emissions and economic weight. By adding New Jersey and Virginia to the program, the combined GDP of the RGGI states would rise from $3.3 trillion to $4.5 trillion, a 35% increase, the equivalent of the world's 4th largest economy. As shown in Figure 6, expanding the RGGI cap to include these states would increase the amount of CO_2 emissions that face a carbon price by 60%.

Figure 6: RGGI Cap with New Jersey and Virginia



Conclusion

RGGI has successfully demonstrated the viability of a market-based program to reduce CO_2 emissions from the power sector while generating benefits for participating states. RGGI's experience has disproven the concerns most frequently associated with capping emissions from the power sector. Emissions have declined rapidly, far more dramatically than projected, without stifling economic growth. RGGI's reinvestment model has benefited the regional economy and increased employment while accelerating deployment of renewable energy and funding energy efficiency programs. The region's residents now pay lower electricity prices than before the program began and breathe cleaner air.

The RGGI states have committed to build on this success by extending the program through 2030. In the coming years the RGGI states will need to conduct another Program Review to reevaluate how the program aligns with the achievement of state climate targets.

A cleaner electric grid will prove vital to delivering significant CO_2 reductions from the electrification of transportation and buildings – the two other key sectors that must be decarbonized to avert climate disaster. By strengthening RGGI and applying lessons learned from the program to the transportation sector, the region can take meaningful action to address vehicle pollution—the largest source of CO_2 emissions in the country. Many of the RGGI states are currently building on their track record of bipartisan collaboration to develop a regional cap-and-invest program for the transportation sector through the Transportation and Climate Initiative (TCI). If this program applies the best of the RGGI model while delivering an even bolder, more equitable framework, the region will be well on its way to a low-carbon future that works for all.

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[xvii] In order to compare emissions in the RGGI states to emissions in the rest of the country, the emissions measured in this section are from EIA Form 923. This represents a broader range of emissions sources than those covered by RGGI, which explains the difference in reported RGGI emissions here versus elsewhere in this report.

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Attachment 40

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

THE ECONOMIC IMPACTS OF THE REGIONAL GREENHOUSE GAS INITIATIVE ON NINE NORTHEAST AND MID-ATLANTIC STATES

Review of RGGI's Third Three-Year Compliance Period (2015-2017)

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April 17, 2018

An independent research project of

THE RGGI PROJECT SERIES

Acknowledgments

This is an independent report on the economic impacts of RGGI program implementation, primarily covering the third three-year period of the program (2015-2017), which is known as Compliance Period 3. This Report complements two previous studies completed by Analysis Group in November 2011 and July 2015 on RGGI's Compliance Periods 1 and 2 (2009-2011 and 2012-2014, respectively). The analytic method and structure of this Report follow closely upon those used in the prior reports in order to ensure methodological consistency and provide continuity in focus, content and the consideration of lessons learned. Where relevant in this Report, we include data, information and observations particular to the 2015-2017 period, and elsewhere summarize developments and outcomes in all three Compliance Periods, covering all nine years of RGGI (2009-2017).

This Report is part of the RGGI Project Series: a series of independent and nonpartisan research and analysis projects to inform and assist leaders and stakeholders in the Northeast and other states.

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About Analysis Group

Analysis Group is one of the largest economic consulting firms globally, with more than 850 professionals in 14 offices in North America, Europe, and Asia. Analysis Group provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies.

Analysis Group's energy and environment practice area is distinguished by expertise in economics, finance, market modeling and analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. Members of Analysis Group's practice have worked for a wide variety of clients including: energy producers, suppliers and consumers; utilities; state regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; start-up companies; and others. For more information, visit **www.analysisgroup.com**.

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1. EXECUTIVE SUMMARY

Overview and Context

In 2009, ten Northeastern and Mid-Atlantic states launched the Regional Greenhouse Gas Initiative ("RGGI"), the country's first market-based program to reduce emissions of carbon dioxide ("CO_2") from existing and new power plants.[1] The scope of RGGI is significant: the current set of RGGI states account for more than one-eighth of the population in the U.S. and more than one-seventh of the nation's gross domestic product. It is thus important to evaluate and understand the program's performance and outcomes. Through their development and implementation of the RGGI program, these states have gained first-mover policy experience and have collaborated to form a multi-state emission-control policy that has reduced CO_2 emissions from the power sector and operated seamlessly with well-functioning and reliable electricity markets.

Recently, other states have expressed interest in implementing carbon-control programs that are similar in structure to RGGI's approach. One option for those states would be for active collaboration to allow for trading of CO_2 allowances among affected sources in these states and the current RGGI states.[2] Insights and observations gleaned from an analysis of RGGI's performance could thus be valuable not only to the RGGI states as they consider future policy recommendations but also to other states and regions as they develop their own plans to reduce CO_2 emissions.

This Report analyzes the economic impacts of RGGI's most recent three-year compliance period, which spanned 2015 through 2017. This analysis follows our two prior reports on the economic impacts of RGGI: the 2011 Report (hereafter "AG 2011 Report") which assessed the economic impacts of RGGI's first three-year compliance period (2009-2011), and the 2015 Report (hereafter "AG 2015 Report") which assessed the economic impacts of RGGI's second three-year compliance period (2012-2014).[3]

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[1] The ten original RGGI states were Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. New Jersey participated in the first three years of the RGGI program, and withdrew its participation at the end of 2011.

[2] See, *e.g.*, the recent statement by Ben Grumbles, Secretary of the Maryland Department of the Environment and Chair of the RGGI, Inc. Board of Directors, regarding RGGI's interest in sharing information "…with any state that is interested, and especially look forward to further discussions with Virginia and New Jersey." (See https://rggi.org/sites/default/files/Uploads/Auction-Materials/39/PR031618_Auction39.pdf)

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There have been a number of relevant developments since our last economic review of RGGI in 2015. The electric industry has experienced changes in power-generation economics, emission-control requirements, and wholesale market structures in the RGGI region. In addition, absent federal requirements, a number of states continue to seek to address greenhouse-gas ("GHG") emissions through an assortment of policy mechanisms. Finally, the RGGI states have undertaken a second comprehensive Program Review, completed in December 2017, which led to modified elements of the program including adopting a 30-percent reduction in the regional cap between 2020 and 2030.

In this Report, we examine RGGI's recent economic performance under these changing economic and regulatory realities. We hope that the results of our assessment and lessons learned are useful not only to the RGGI states but also to others that have expressed interest in establishing carbon control programs (including with the possibility of linking to or participating in the RGGI program).[4]

RGGI has now been operating for over nine years. In every year, CO_2 emission allowances have entered the market through coordinated (centralized) regional auctions. Owners of fossil-fueled power plants have spent nearly $2.8 billion to buy CO_2 allowances over the nine years. In turn, offer prices in the regional wholesale electricity markets reflect these purchases, and grid operators in these regions use these offer prices to dispatch power plants economically while maintaining system reliability.

Since 2009, the RGGI states have received virtually all of the nearly $2.8 billion in proceeds from CO_2-allowance auctions and disbursed them back into the economy in various ways, including through expenditures on: energy efficiency ("EE") measures and programs; renewable energy ("RE") projects; GHG-emission reduction measures; direct electricity consumer bill assistance, including for low-income households; and education and job training programs. These local investments keep more of the RGGI states' energy dollars in their region, and reduce the amount of dollars that leave the region to pay for fossil fuel resources produced outside the RGGI states.

What We Study in this Report:
The Economic Impacts of RGGI (2015-2017)

Our analysis tracks the path of RGGI-related dollars over the past three years as they leave the pockets of fossil-fuel power generators to buy CO_2 allowances, show up in electricity prices and customer bills, make their way into state expenditure accounts, and then roll out into the economy through the expenditure of the allowance auction proceeds.

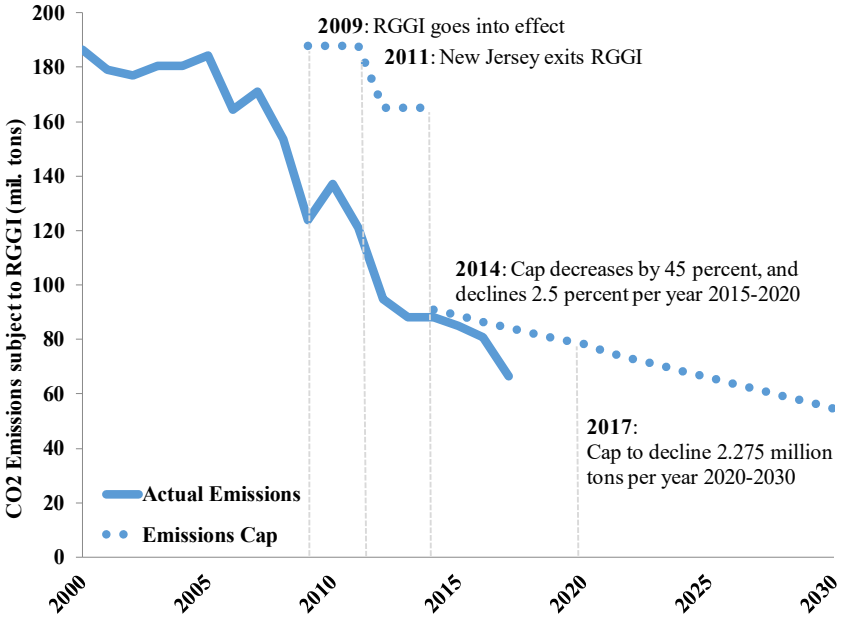
Our analysis thus focuses on the actual economic activity that results from RGGI: known CO_2 allowance prices; observable CO_2 auction results; dollars distributed from the auction to the states; actual state-government decisions about how to spend the allowance proceeds; measurable reductions in energy use from energy-efficiency programs funded by RGGI dollars; traceable impacts of lower energy use on wholesale power prices; and concrete value added to the economy.

By carefully examining the RGGI states' implementation of the program to date, based on real historic data, we hope to provide a foundation for observations that can be used by others in the design of CO_2 control programs going forward.

[4] See, *e.g.*, RGGI Inc., Statement on Proposed Virginia Greenhouse Gas Rule, November 9, 2017.

Throughout the RGGI program's implementation, power system reliability has been maintained. And as shown in Figure ES-1, CO_2 emissions from power generation have decreased in the RGGI region (due to RGGI program design and implementation but also broader economic and industry factors).[5]

Figure ES-1
Actual CO_2 Emissions in the RGGI States and Evolution of the RGGI CO_2 Emissions Cap



Source: RGGI, Inc. data from the RGGI CO_2 Allowance Tracking System (COATS), accessed March 2, 2018.

With these many insights, we address several questions in this Report: What happened to the roughly $1 billion in proceeds from the sale of CO_2 allowances over the 2015-2017 period? Has the RGGI program produced net economic benefits to these states in Compliance Period 3 (as it did in the first two compliance periods)? Are there new learnings from the outcomes of the RGGI program to date beyond those identified and described in our prior reports?

Finally, in this Report we consider the implications of our analysis for continued implementation in the RGGI states, and for states considering development of their own carbon reduction programs and/or coordination with a broader CO_2 trading region.

[5] RGGI, Inc. data show that CO_2 emissions from RGGI electric generation sources decreased by 75.8 million short tons, or *53.3 percent* compared to the average baseline emissions between 2006 and 2008. Note that these figures exclude New Jersey, which was a RGGI member during the first compliance period. Data available at https://www.rggi.org/allowance-tracking/rggi-coats, accessed April 4, 2018.

Results

Over the last three years (2015-2017), the RGGI program led to $1.4 billion (net present value ("NPV")) of net positive economic activity in the nine-state region.[6] Each RGGI state's electricity consumers and local economy also experienced net benefits from the RGGI program. When spread across the region's population, these economic impacts amount to nearly $34 in net positive value added per capita. Figure ES-2 shows the net economic value to the nine-state RGGI region as a whole, with results also broken out by power system region (with the six New England states participating in the ISO-New England electrical region, with New York participating in the one-state NYISO system, and with Maryland and Delaware participating in the multi-state PJM power system).

Figure ES-2
Net Economic Impact of the Implementation of RGGI During the 2015-2017 Period (NPV, 2018$)

Notes: [1] Figures are reported in 2018 dollars (NPV), converted using a 3-percent public discount rate. [2] Total economic value added reflects the impacts of state spending of RGGI proceeds, including net electric sector impacts to consumers and power plant owners, non-electric benefits, and the economic impact of program spending.

RGGI's net positive economic outcome results in large part from the states' decisions to sell CO_2 allowances via a centralized auction and then to use the auction proceeds in various ways that address state policy objectives. This approach has been in place in all three RGGI compliance periods. As in the prior years, during the 2015-2017 period the states received and spent the roughly $1.0 billion in auction proceeds primarily on EE measures, community-based RE projects, customer bill assistance, other GHG-emission reduction measures, and on research, education and job training programs.

[6] All results for Compliance Period 3 are reported in 2018 dollars, with results reported using a 3-percent "public" discount rate. See the Appendices for a discussion of public and private discount rates.

These economic benefits reflect the complex ways that RGGI dollars interact within local economies.

Compared to energy-related dollar flows that would occur in the absence of the RGGI program, energy-related expenditures with RGGI lead to more purchases of goods and services in the RGGI states' local economies. Take the use of the auction proceeds on EE measures, for example: Such expenditures include payments for engineering services for energy audits, sales of energy-efficient equipment, dollars spent to train those installers, and state taxes collected on all of these activities. Together, these dollar flows have direct and indirect multiplier effects locally and regionally.

The size of RGGI's economic impacts varies by state and region, in large part because the states spent their RGGI auction proceeds differently.[7] Different expenditures have different direct and indirect effects on their economies and on their electric systems. For example, a state's use of RGGI dollars to pay for EE measures that reduce electricity consumption and to invest in RE facilities with low operating costs both served to lower electricity prices in wholesale power markets (as compared to a "without-RGGI" scenario). This in turn lowers consumers' electricity bills over time.

Local investment of RGGI dollars on energy efficiency and renewable energy offset the impact on electricity prices resulting from CO_2 allowance costs.

On the one hand, the inclusion of the cost of CO_2 allowances in wholesale prices tends to increase wholesale electricity prices in the RGGI region at the beginning of the 2015-2017 period. But these near-term impacts are more than offset during these years and beyond, because the states invest a substantial amount of the RGGI auction proceeds on EE programs that reduce overall electricity consumption and on RE projects that reduce the use of higher-priced power plants. Consumers gain because their overall electricity bills go down. Since RGGI's commencement in 2009, energy and dollar savings resulting from all states' investments in EE and RE has more than offset the wholesale market price increases associated with inclusion of allowance costs in market bids.

Energy consumers enjoy a net gain of $220 million as a result of the RGGI program (2015-2017), as their overall energy bills drop over time.

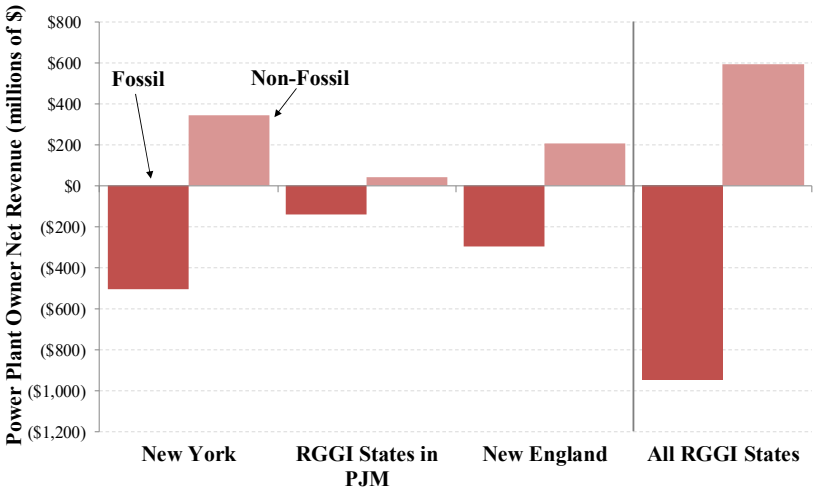
Net benefits accrue to residential, commercial and industrial customers. Consumers of electricity save $99 million, and consumers of natural gas and heating oil save $121 million. These amounts are in addition to the economic benefits they receive as members of the local economies of the RGGI states where the allowance auction proceeds are spent.

[7] Overall, the distribution of spending across the RGGI states was as follows: 52% on EE; 18% on RE projects; 13% on bill-payment assistance to consumers; 7% on program administration; 4% on GHG-emission reduction programs; 3% on clean technology research and development; 2% on education, outreach, and job training; and 1% for payments into a general fund. Individual state expenditures varied significantly across these categories.

Power system changes that result from RGGI include: different dispatch order of power plants; plants with lower CO_2 emissions having a competitive advantage; and owners of emitting power plants recovering the costs of CO_2 allowances in the short run while experiencing lower output and revenues in the long run.

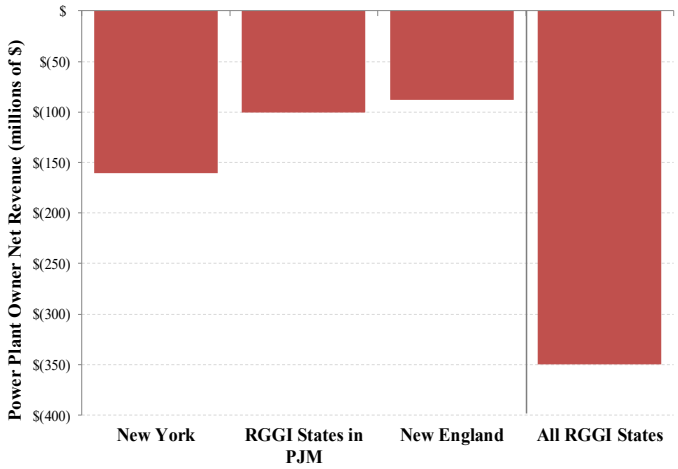
Including a price on CO_2 emissions tends to shift the power plant dispatch order and increase output of lower- and zero-carbon-emitting sources of power. Although RGGI requires owners of emitting power plants to purchase CO_2 allowances, power plant owners as a group recover all of their early expenditures on CO_2 allowances through the increase in wholesale electricity prices in the near term. But the net effect of the program tends to reduce the revenues of owners of plants over time as a result of RGGI expenditures on EE, which lower the demand for power. Plants with relatively high carbon emissions (*e.g.*, coal-fired or oil-fired units) collect less revenues over time while owners of zero-carbon generating sources (*e.g.*, nuclear, wind, solar, hydro) get the benefit of being paid higher wholesale market prices that reflect CO_2 allowance costs, without having to buy allowances. Figure ES-3 shows the changes in net revenues for power plant owners as a result of the RGGI program, with results broken out by location and by power-plant fuel type. Carbon-emitting power plant owners generally lose revenue ($940 million), while owners of nuclear and renewable resources gain ($590 million). On an NPV basis, total revenues to the power-generation sector drop by nearly $350 million through our forecast period (ending in 2027), as shown in Figure ES-4.

Figure ES-3
Net Revenue Change to Power Plant Owners (by Power-Plant Fuel Type and Electrical Region) as a Result of RGGI Implementation During the 2015-2017 Period (NPV, 2018$)



Notes: [1] Figures are reported in 2018 dollars (NPV), using a 3-percent public discount rate. [2] Figures include PROMOD outputs for energy prices and revenues and for capacity-market revenue changes that are calculated separately. [3] "Fossil" includes natural gas, oil, and coal-fired generators. "Non-fossil" includes nuclear, hydro, pumped storage, wind, solar, and biomass.

Figure ES-4
Net Revenue Change Across All Power Plant Owners, by Region, as a Result of RGGI Implementation During the 2015-2017 Period (NPV, 2018$)

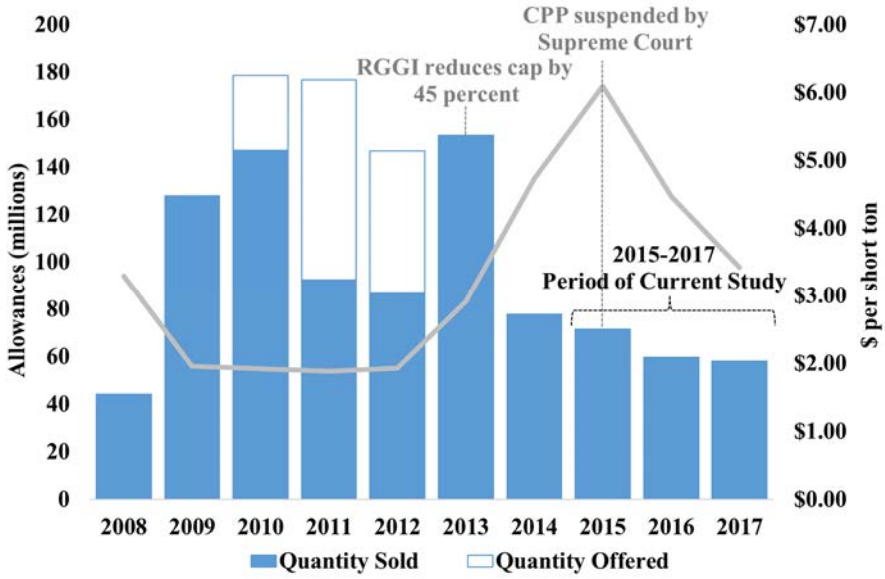


Notes: [1] Figures are reported in 2018 dollars (NPV), using a 3-percent public discount rate. [2] Figures include PROMOD outputs for energy prices and revenues and for capacity market revenue changes calculated separately.

Compared to RGGI's earlier two compliance periods (2009-2011 and 2012-2014), the amount of CO_2 allowances sold dropped in recent years, while clearing prices were on average higher, which had a mostly offsetting effect on the relative magnitudes of economic effects experienced in Compliance Period 3.

The RGGI states lowered the regional CO_2 emissions cap by 45 percent in 2014 and further tightened it by 2.5 percent per year thereafter, during the current study period (see Figure ES-1). The current compliance period was the first that involved a significantly tightened and declining cap (see Figure ES-1). This tightening supply of CO_2 allowances, in combination with other market and policy factors, initially elevated the price of allowances and, in turn, the wholesale power prices in the different parts of the RGGI region. Total auction proceeds in Compliance Period 3 ended up being only slightly lower than in each of the prior two periods (by less than ten percent), reflecting the offsetting impact of higher allowance prices and lower allowance volumes sold (as shown in Figure ES-5).

Figure ES-5
RGGI Auction Allowances and Clearing Prices



Notes:
[1] Clearing prices are weighted averages, based on number of allowances sold.
[2] In 2014 and 2015, the Cost Containment Reserve ("CCR") trigger price was exceeded and additional allowances above what were originally offered into the market were ultimately presented and sold to market participants. In 2014 and 2015, 5 million and 10 million additional allowances were sold, respectively.
Source: RGGI, Inc., http://www.rggi.org/market/co2_auctions/results.

Observations

Based on these results as well as those in our prior assessments of the first two RGGI compliance periods, we have a number of observations that we summarize here. We hope that these provide useful information for the RGGI states as they consider how the program is performing relative to its original goals and for other states and stakeholders who are interested in carbon emission-control policies and programs.

As in its first six years, the RGGI program's third three-year compliance period continued to generate substantial economic benefits for the states while reducing CO_2 emissions.

Economic value added

Our analysis of RGGI impacts over the past three years took into consideration the program's effects on power system dispatch, costs to consumers, revenues to electric generators, and overall performance of the economies in the participating states. Even taking into account decreased revenues to the owners of emitting power plants (and to power-plant owners as a whole), we found positive macroeconomic impacts to the states due to the net benefits to electric consumers and the expenditures of the CO_2 allowance proceeds. RGGI led to approximately $1.4 billion in economic value added (NPV, 2018$) as a result of program implementation in the 2015-2017 period. Thus, the RGGI program continues to generate economic value for its member states.

Jobs

Taking into account the gains and losses to consumers and producers, RGGI Compliance Period 3 led to overall job increases amounting to thousands of new jobs over time. Some of the RGGI job impacts may be permanent, while others may be part-time or temporary. According to our analysis, the net effect is that RGGI activity during the 2015-2017 period leads to over 14,500 new job-years, cumulative over the study period, with each of the nine states experiencing net job-year additions. Jobs that result from RGGI-related expenditures occur in many parts of the economy, with examples including workers who perform efficiency audits and who install energy efficiency measures in residences and commercial buildings, and staff performing training on energy issues.

Fossil-fuel production and imports

Over the past three years, RGGI helped to lower the total number of dollars (by $1.37 billion (NPV, 2018$)) its member states sent outside their region in the form of payments for fossil fuels for power generation and other purposes. Most of the RGGI states' electricity comes from fossil fuels, even though these states produce little coal, natural gas, or oil. Because the RGGI program lowered these nine states' total fossil-fired power production and also reduced their use of natural gas and oil for heating, RGGI reduced the total dollars sent out of state for these energy resources.

Continuation of RGGI program benefits above and beyond the first six years

Our findings on economic impacts of RGGI's third three-year compliance period are consistent with the findings and observations we made with respect to the first and second three-year compliance periods. Those prior assessments revealed net economic benefits to the states participating in the program, including growth in economic output, increased jobs, reinvestment of energy dollars in local/state economic activity, long-run wholesale electricity cost reductions, and CO_2 emission reductions.

Many factors have changed in the electric industry and the economy since we completed our economic analyses of the RGGI program for Compliance Period 1 (2009-2011) and for Compliance Period 2 (2012-2014). These changes have affected the conditions (*e.g.*, lower gas prices, generation retirements and additions) analyzed in our assessment of Compliance Period 3.

For many reasons (such as the different vintages of each of our studies and notably the year in which we report NPV results), the results of our three studies are not directly additive. Even so, across the three studies, we have found net economic benefits to the RGGI states. Recognizing that these studies have reported outcomes in different-year dollar values, each of our assessments has found positive benefits for the participating RGGI states: $1.6 billion (NPV, in 2011$), $1.3 billion (NPV, in 2015$), and $1.4 billion (NPV, in 2018$) for Compliance Periods 1, 2, and 3 respectively.[8] Our studies have also found that the RGGI-related expenditures led to job creation in each of the three

[8] In addition to our prior studies of the RGGI program, RGGI, Inc. and others have conducted studies of the economic impacts of the program. We discuss the differences in these studies later on in this report.

compliance periods of approximately: 16,000 job-years (as of 2011); 14,200 job-years (as of 2015); and 14,500 (as of 2018), respectively.[9]

Thus our modeling of the three compliance periods indicates that, its first decade, RGGI's carbon cap-and-trade program has generated net positive economic value for the participating states' economies on the order of $4 billion dollars.[10] States' participation in RGGI has led to tens of thousands of job-years while also helping to reduce carbon emissions in the RGGI states' electric sector. At the same time, annual carbon-emissions have dropped nearly 50 percent since the program's start in 2009 (for many reasons, including implementation of RGGI).

RGGI's first nine years (2009-2017) provide empirical evidence that carbon-control programs for the power sector can provide positive economic outcomes.

Review of the nation's first multi-state CO_2 emission-control program provides useful information for states that are considering emission-reduction options.

Despite a recent lack of progress at the federal level, many state policymakers continue to focus their attention on the various alternatives for reducing emissions of CO_2 from the electricity sector (and other sectors). A wide range of alternatives are available including cap-and-trade programs, carbon tax/pricing approaches, energy research and development ("R&D") funding, consumer-funded procurements of low- and zero-carbon energy sources, rate policies supporting distributed-energy resource development, and funding of energy efficiency measures. The diverse set of policy options used reflects many states' interest in finding cost-effective and workable ways to cut CO_2 emissions. Lessons learned from RGGI's implementation can inform states as they consider their options.

The experience of the RGGI states, including their initial efforts that began in 2003 to work together to develop a multi-state, market-based CO_2 control program, through the nine years of program administration to date, provides a wealth of information. Their experience provides many lessons, most notably that states can collaborate successfully in developing programs to control CO_2 emissions, and market-based CO_2-allowance trading programs – combined with state-driven centralized auctions of CO_2 allowances and with local reinvestment of auction proceeds – can help states meet emission-reduction targets while generating positive economic benefits.

RGGI's positive impacts on state economies are additive to the purpose and expected benefits of the program.

RGGI is not and never was meant to be an economic development program. RGGI's purpose is to reduce CO_2 emissions from power generation in order to help mitigate the economic, social, and environmental risks of climate change. As shown in Figure ES-1, RGGI has contributed to

[9] These reflect "job-years," and do not identify what portion of these numbers are associated with permanent versus temporary jobs. Job-years are reported cumulatively over the full study period.

[10] As noted earlier, while the economic results from our three studies are not directly additive, we have used the same foundational analytic methods, assumptions, and data sources across all three studies in order to ensure consistency in study results. While changes in the assumptions used in our earlier studies – *e.g.*, to reflect current market conditions and expectations – could change the results (in either direction), we expect such changes would be small given the consistency in the level of allowance proceeds collected and used by the RGGI states and in the benefits we have found across our studies.

significant reductions in emissions of CO_2 across the RGGI region. In our economic analysis of the RGGI program, however, we do not attempt to quantify the potential long-term benefits of reducing the risks of climate change. The focus of our analysis is specific and narrow: to review the direct impacts of program implementation on the economies of the RGGI states, in order to test the presumption that controlling emissions of CO_2 will somehow lead to negative consequences for states that take action. Our results – which instead reveal positive economic impacts – should be viewed as additive to whatever other benefits flow from reducing climate-change risks.

The RGGI model has successfully achieved CO_2 reductions through a cooperative multi-state framework that preserves state authority.

The states that comprise the RGGI region are highly diverse in many ways: their political settings and policy objectives vary widely across the states and have even changed significantly *within* states over time; their electric-generating portfolios differ substantially in size, technologies, fuel mix, and age; their economic bases vary; and the states have unique legal and regulatory structures that oversee energy, utility, and environmental policies. Despite these differences, however, the RGGI states' experience confirms the possibility that states can work together, particularly when doing so is likely to lower compliance costs and generate economic benefits. The states have designed a multi-state CO_2 program consistent with sound economic principles, completed the stakeholder, legislative, and regulatory steps necessary to adopt and implement the program, and smoothly administered the program and integrated it with wholesale electricity markets. In addition, over just ten years the states have completed two top-to-bottom programmatic reviews and agreed upon major changes to the framework. The RGGI states continue to implement the RGGI platform with an eye towards inclusion and a willingness to collaborate with other states outside the current nine-state region.

Mandatory, market-based carbon-control mechanisms are functioning properly in wholesale electricity markets and have not adversely affected system reliability.

RGGI's nine years of experience supports a conclusion that market-based CO_2 emission-control programs can produce positive economic impacts and meet emission objectives while dovetailing smoothly into the normal operation of power systems. RGGI's implementation has not adversely affected power system reliability in New England, New York, or PJM. Further, RGGI provides an important example of how states' public policies can be integrated into federally regulated competitive wholesale markets – an issue with which FERC, state regulators, and the courts are actively wrestling.

The design of the CO_2 market in the RGGI states has allowed for the creative use of public assets in support of diverse state energy/environmental policy and economic outcomes.

The joint decision by the RGGI states to make their CO_2 allowances available to the market through a unified auction has generated substantial revenues for public use. This approach transferred the value of emissions allowances from the public sector to the private sector at a monetary cost. Had the allowances been given away for free, the states would not have had the benefit of the auction proceeds and instead would have transferred away significant public economic value to owners of power plants (which in the RGGI region are merchant generators, not owned by electric distribution utilities). The states' use of allowance proceeds helped them meet a wide variety of social, fiscal, and environmental policy goals, such as assisting low-income customers, achieving advanced energy

policy goals, and restoring wetlands, among other things. Notably, however, auctioning of allowances is not necessary for the efficient and effective functioning of the cap-and-trade program design itself. Individual states may still determine their preferred method of moving allowances into the market, which could include auctions, direct allocation, and other mechanisms that may move allowances into the market while transferring or consigning auction value in whole or in part to other entities (such as electric distribution utilities or generating asset owners).

> How allowance proceeds are used affects their economic impacts: Use of auction proceeds to invest in energy efficiency produces the biggest economic bang per buck, in terms of net positive benefits to consumers and to the economy.

The RGGI Memorandum of Understanding ("MOU") fully supports the reality that states place different weights on various goals they hope to accomplish through participation in the program, and that the states will make their own decisions about how to allocate allowances to the market and how to use the proceeds from allowance auctions. But from a strictly economic perspective, some uses of proceeds clearly deliver economic returns more readily and substantially than others. For example, RGGI investment in EE leads to lower electrical demand, lower wholesale power prices, and lower consumer electricity bills. These savings remain in the pockets of electricity users, and the EE investments also produce positive macroeconomic impacts locally as more dollars stay in and contribute to the local economy. We observe that use of the RGGI dollars provides positive multiplier effects in the RGGI states' economies, especially compared to other uses of the auction proceeds.

The RGGI states' experience during 2015-2017 differed along a number of dimensions relative to the first six years of the program.

The RGGI program as implemented during the 2015-2017 period took place in the context of a changing industry and regulatory landscape and with significant changes adopted and implemented by RGGI states. Specifically:

- During 2017, the RGGI states used the six years of prior program experience as they undertook a top-to-bottom review of RGGI, and made a number of changes in the program.
- Many states adjusted how they spent RGGI auction proceeds over time, shifting the use of allowance revenues to reflect changing program and state objectives.
- Fossil fuel prices changed significantly since the start of the program, with natural gas prices (and in turn, wholesale electricity prices) having decreased substantially.
- Electric resources have shifted, with accelerated retirements of older and less efficient (and in most cases, higher-emitting) generating units, and with distributed and central-station renewable energy resources growing at a rapid pace in many of the RGGI states.

Such factors have the potential to influence the administration of RGGI and associated power system and economic impacts. For example, the lower average natural gas prices in 2015-2017 relative to the prior six years led to lower electricity prices in wholesale power markets, which had the effect of reducing the economic value of RGGI-funded EE programs for electricity and heating consumers. Also, the tightening of RGGI's CO_2 emissions cap contributed to an increase in allowance prices, the operating costs of affected generating units, and impacts on wholesale electric prices. The lower number of allowances available to the market, however, was in part offset by higher allowance prices,

and thus only slightly reduced auction proceeds available to RGGI states during the 2015-2017 period.

Despite the shifting context for RGGI, the core elements of the program – including a declining CO_2 emissions cap, allowance auctions, reinvestment of auction proceeds, active trading of allowances, monitoring of program administration, participation and outcomes, and cooperation among a diverse set of states and stakeholders – operate in ways that continue to produce positive economic and programmatic results for the participating states.

2. THE REGIONAL GREENHOUSE GAS INITIATIVE

Overview and Purpose

With the first auction of CO_2 allowances in late 2008, ten states in the Northeast and Mid-Atlantic regions initiated RGGI, a multi-state market-based program to reduce emissions of CO_2.[11] In doing so, the states created the country's first mandatory program to cap emissions of CO_2 from power generation sources, with the cap set initially at 188 million short tons of CO_2 annually across the ten-state RGGI region. The regional cap is apportioned to states in a manner based generally on emissions from the affected sources (*i.e.*, fossil fuel power plants that are 25 megawatts or more in size), and in accordance with specific state allowance budgets agreed upon by the states.

As originally designed, the cap would decline by 2.5 percent per year beginning in 2015, to reach an overall reduction of 10 percent of CO_2 emissions by 2018.[12] Under the Revised Model Rule, released in February 2013 and discussed further below, the RGGI states revised the regional emissions cap downward to 91 million tons in 2014 and maintained the original 2.5-percent per-year reduction to the regional cap for the years 2015 through 2020. Under the 2017 Model Rule, released in December 2017, the cap will be further reduced by an additional 30 percent between 2020 and 2030.

Although they had the option to distribute allowances for free, each state decided at the outset of the program in 2009 to distribute the vast majority of CO_2 emission allowances into the market through a centralized auction, administered by RGGI, Inc., the non-profit organization set up by the states to run the program.

The states developed the RGGI program over several years starting in late 2003 to begin to address the risks associated with climate change. Given the electric sector's significance as a source of CO_2 emissions, the states focused attention on the goal of designing and implementing a program to reduce CO_2 emissions from power generation within the signatory states. The states acted more than a decade ago, commencing with their December 2005 Memorandum of Understanding ("MOU"), in which they concluded that: (1) climate change is occurring; (2) it poses serious potential risks to human health and the environment; (3) delay in addressing CO_2 emissions will make later investments in mitigation and adaptation more difficult and costly; and (4) a market-based carbon allowance trading program will create strong incentives for the development of lower-emitting energy sources and energy efficiency, and reduce dependence on imported fossil fuels.[13]

Market-Based Mechanism

RGGI is an emissions-control program based on market principles. Similar to that of other market-based programs administered for control of nitrogen oxides (NO_x) and sulfur dioxide (SO_2), the

[11] The ten states are Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. New Jersey participated in the first three years of the RGGI program, withdrawing its participation at the end of 2011.

[12] Information on RGGI is drawn from various fact sheets on the website of RGGI, Inc., the non-profit organization established by the states to administer the RGGI program. (See http://www.rggi.org/)

[13] Regional Greenhouse Gas Initiative Memorandum of Understanding, December 20, 2005 (hereafter referred to as "MOU"), pages 1-2.

foundation of the RGGI program is an annual cap on emissions of CO_2 in aggregate for all affected sources in the states that participate in the program. Affected or "regulated" sources in a given state generally include all fossil-fueled electric power generators with a capacity of equal to or greater than 25 megawatts. Program compliance is relatively straightforward: shortly after the end of each three-year compliance period (*e.g.*, with Compliance Period 3 covering 2015, 2016 and 2017), every affected source must retire a number of allowances equal to the total tons of CO_2 emissions from the source over the three-year compliance period (one allowance equals one ton of emissions). Affected units may obtain allowances at various points in time prior to the end of the compliance period.

The states' selection of a market-based control program for CO_2 emissions from the power sector reflects the history and success within this region of market-based programs established under the federal Clean Air Act for control of SO_2 and NO_x emissions. It is also a natural fit for the electric industry given the ease with which allowance costs can be incorporated into competitive wholesale electricity market pricing systems.[14] Affected sources obtain (*e.g.*, purchase) allowances, which then becomes part of their cost to produce power at their generating unit and is included as part of their offer prices to participate in wholesale markets. This mechanism allows wholesale prices to reflect carbon prices, leading over time to industry operational decisions (relating to power plant dispatch) and asset investment decisions that reflect the most efficient compliance path for individual regulated entities as well as for the industry as a whole. In this context, the use of a market-based control program for CO_2 encourages efficiency in power dispatch decisions and long-run efficiency for achieving compliance with the market-based cap on emissions.

The CO_2 emissions cap is administered through limiting the quantity of allowances issued into the market in a given year. For example, 188 million allowances were available for the year 2009, and 84.3 million were available for 2017. The owners of affected power plants generally obtain CO_2 allowances by purchasing them through the initial auctions (held quarterly), or by purchasing or otherwise transferring them in a secondary market.

RGGI allows for flexible compliance in a number of ways. First, recognizing the long-lived nature of CO_2 in the atmosphere, compliance is required not annually, but on a three-year basis. That is, sources can purchase, bank, and use allowances bought at any auction for a given compliance period within the three-year compliance period, and need only demonstrate compliance (through retiring allowances in amounts equal to emissions) shortly after the end of that same period. In fact, allowances can be purchased and banked for use beyond the compliance period in which they were purchased. Second, sources can meet up to 3.3 percent of their CO_2 compliance obligation through

[14] The bulk-power electric systems of the nine RGGI states are part of the centrally administered wholesale markets and integrated grids operated by three entities, called Regional Transmission Organizations ("RTOs"): ISO-New England (for the six New England states); the New York Independent System Operator (NYISO) (which is a single-state market); and PJM (for Delaware and Maryland). (PJM also includes power systems in 11 other states and the District of Columbia, which are not part of the RGGI program.) In each of these three RTOs, the wholesale power market has evolved over time into a comprehensive electricity market construct (including energy, capacity, and ancillary services) that shapes the operations of the fleet of power plants in an efficient and reliable way in real time. This electricity market construct also affects the near-term and long-term incentives for the addition of new generating capacity (or the retirement of existing capacity).

the purchase of offsets – that is, GHG-reduction projects outside the power sector.[15]

Allowance Disbursement to the RGGI States and into the Market

In each year, the amount of allowances in the regional cap have been apportioned to the participating states according to an agreed-upon ratio that roughly reflects each state's relative share of regional CO_2 emissions from the power sector as of a historical time period.[16] Under the original terms of the 2005 MOU, the RGGI states agreed that each state would be allowed to determine how it would allocate its share of allowances among owners of power plants and other potentially interested parties, so long as 25 percent of the state's allowances are allocated "for a consumer benefit or strategic energy purpose."[17] As it turned out, all of the participating states decided to disburse virtually all of their allowances through a joint allowance-auction process.

Allowances move into the market in the first instance through a central auction process conducted quarterly by RGGI, Inc. on behalf of the RGGI states.[18] An independent market monitor assesses the performance of the auctions to ensure that they are administered according to auction rules, and that there is no anti-competitive behavior in the market. Participation in the auctions is open to any entity meeting qualification requirements (*e.g.*, financial security requirements), with a ceiling of 25 percent placed on purchases by a single buyer or group of affiliated buyers in each auction.

Proceeds from the quarterly auctions – which are determined by quantities sold and auction clearing price (subject to a reserve (floor) price that is currently $2.15 per allowance)[19] – are distributed to states, and states determine how to use the funds. The final auction in the study period occurred in December 2017, with all of the approximately 14.7 million allowances offered for sale selling at an auction clearing price of $3.80 per allowance.[20] Figure 1 shows RGGI proceeds by state and region over the first three compliance periods.

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[15] The Revised Model Rule released in February 2013 provides a new offset category known as "sequestration of carbon due to reforestation, improved forest management or avoided conversion" that RGGI states may adopt in lieu of the previous "afforestation" category.

[16] See, for example, the original apportionment in the 2005 MOU, Section 2.C.

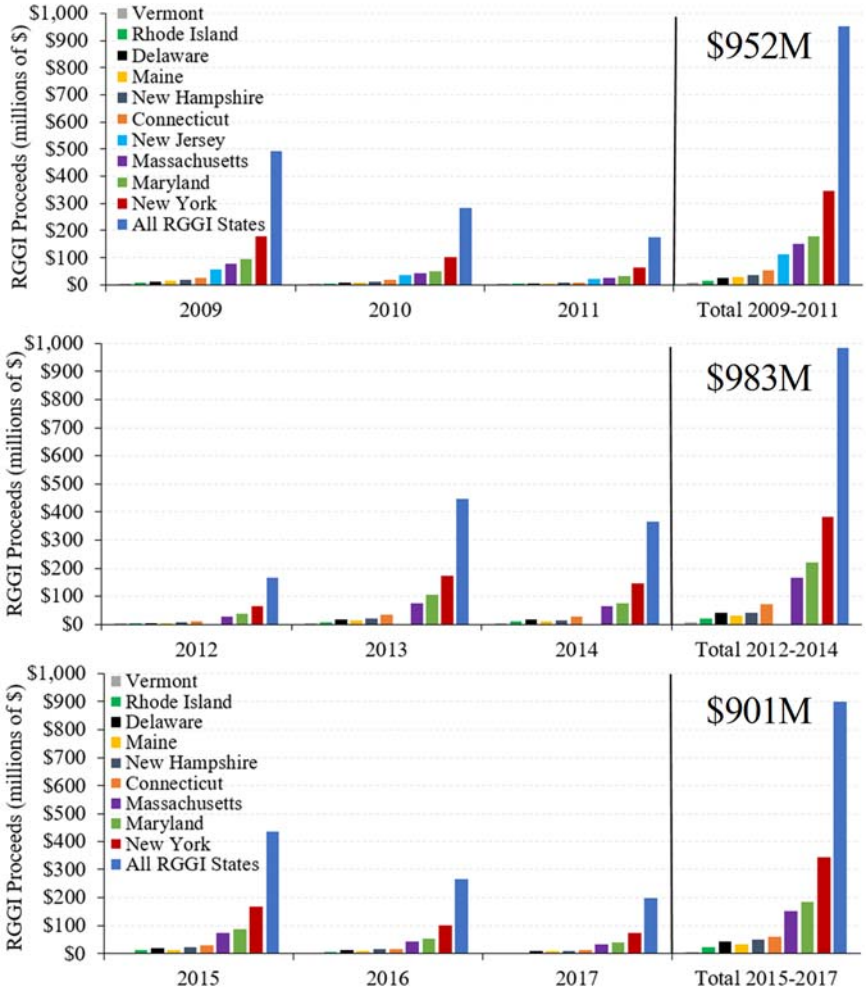
[17] "Consumer benefit and strategic energy purposes include the use of the allowances to promote energy efficiency, to directly mitigate electricity ratepayer impacts, to promote renewable or non-carbon-emitting energy technologies, to stimulate or reward investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and/or to fund administration of this Program;" MOU, Section 2.G.

[18] After the allowances are in the hands of market participants, they may be bought and sold on the secondary market (without revenues flowing to the RGGI states).

[19] The minimum reserve price in 2014 was set at $2.00 and, per the RGGI Model Rule, was set to increase by 1.025 percent each year thereafter. (See https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Model_Rule_2017_12_19.pdf)

[20] In addition, 10 million cost-containment-reserve ("CCR") allowances were also available for sale in Auction 38, none of which have been sold. (See https://www.rggi.org/auction/38). The CCR is a fixed additional supply of allowances that only becomes available for sale if CO_2 allowance prices exceed a certain "trigger" price level, which was $10 in 2017, rising 2.5 percent each year thereafter through 2020 (to account for inflation). After 2020, the trigger price will rise by 7 percent in each subsequent year. (See https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Model_Rule_2017_12_19.pdf)

Figure 1
RGGI CO_2-Allowance Auction Proceeds by State by Compliance Period



Notes: [1] Figures include Auctions 1-38. Auction proceeds from Auctions 1 and 2 (occurring in 2008) are included in 2009. All other values are expressed in nominal dollars in the year the auction proceeds were generated. [2] Figures do not include fixed-price sales proceeds.
Source: RGGI, Inc.

Use of Auction Proceeds and Other Allowance Revenues

The use of auction proceeds varies by state, consistent with enabling state legislation, regulation and policy. Examples of how the states used their funds include investment in EE programs, investment in community-based or private-sector installation of RE or advanced power generation systems, credits to reduce consumers' electricity bills,[21] funding of state government operations through

[21] Note that our study focuses on changes in wholesale electricity prices. Although we recognize that other factors affect the extent to which *retail* electricity prices and electricity bills reflect changes in the world of retail ratemaking, we use the change in wholesale prices as a proxy for changes in consumers' payments for electricity.

allocation to state general funds, education and job training programs, and administration of the RGGI program or other GHG-reduction initiatives. The ways the states used the auction proceeds during the time period reviewed in this study (Compliance Period 3, covering 2015-2017) are discussed in detail below.

RGGI Program Reviews

The RGGI program was designed with a number of specific elements of review and evaluation. The original MOU provided for a comprehensive review to occur in 2012 that would include an evaluation of program successes, program impacts, the potential for additional reductions, imports and emissions leakage, and offsets. That program review took place in 2012. A second program review was conducted in 2017. Each of these reviews culminated in a revised Model Rule, which reflected the outcome of an extensive regional stakeholder process that engaged the state agencies, the regulated community, environmental groups, consumer and industry advocates, and other interested organizations with technical expertise in the design of cap-and-trade programs.

The states' 2012 program review revealed: (1) a significant excess supply of allowances relative to actual emission levels in the region; and (2) a finding that the then-current cost-control measures in the program, which were based upon expansion of the percentage of offset allowances allowable for compliance, would likely be ineffective in controlling costs if the emissions cap was made binding. As a result, the RGGI states revised the original program cap downward[22] and established a Cost Containment Reserve ("CCR") through the release of an Updated Model Rule.[23] These changes were implemented by the RGGI states.

The RGGI states' 2017 program review similarly resulted in: (1) a 30-percent reduction in the cap between 2020 and 2030 (a decline of 2.275 million tons per year); (2) additional adjustments to the cap to account for banked allowances at the end of 2020; (3) setting the size of the CCR to be equal to 10 percent of the cap, and increasing the trigger price to be equal to $13.00 in 2021; and (4) implementation of an Emissions Containment Reserve ("ECR") in 2021, through which states

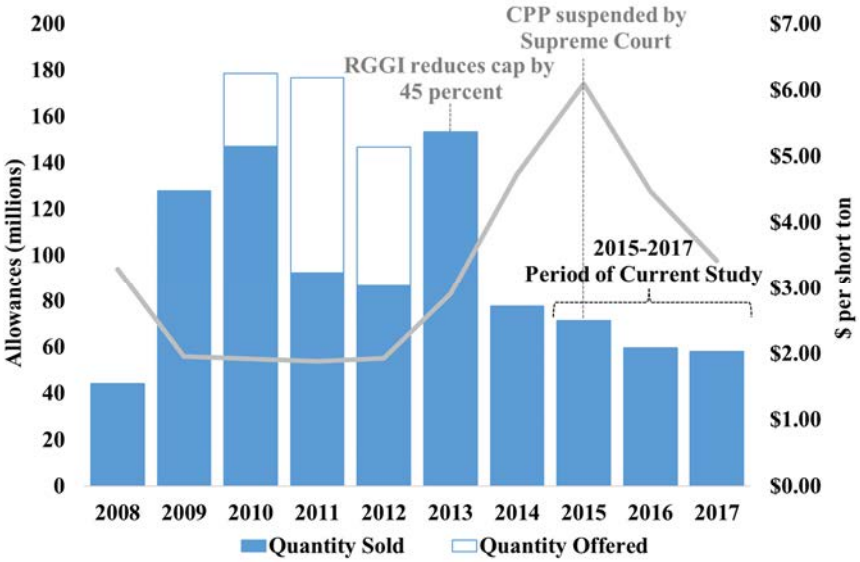
[22] Under the 2013 Updated Model Rule, the regional emissions cap was set equal to 91 million tons for 2014. Afterwards, the regional emissions cap and each RGGI state's individual emissions budget was set to decline 2.5 percent each year from 2015 through 2020. The 2013 Updated Rule also addressed the bank of allowances held by market participants with two interim adjustments for banked allowances: The first adjustment was to be made over a 7-year period (2014-2020) for the first control period private bank of allowances and a second adjustment was to be made over a 6-year period (2015-2020) for the 2012-2013 period private bank of allowances. (See https://rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/2013-02-11/Recommendations_Summary.pdf and https://rggi.org/sites/default/files/Uploads/Design-Archive/Model-Rule/2012-Program-Review-Update/Summary_of_Model_Rule_Changes_02_07_13.pdf)

[23] The Updated Model Rule established a CCR, which is a reserved quantity of allowances additional to the cap and that is only available to be released into the market if defined allowance price triggers are exceeded. In 2014, the amount of additional allowances in the CCR equaled 5 million short tons, and 10 million short tons were provided each year thereafter.

withhold allowances to achieve emissions reductions if prices fall below the established trigger price, which will start at $6.00.[24]

These reductions in RGGI's cap have resulted in several outcomes in recent years. Fewer allowances are being offered and sold. The auctions are producing higher clearing prices (and thus higher compliance costs). And together, the lower number of allowances at higher prices have led to slightly lower auction proceeds to RGGI states when compared to the first and second compliance periods. As summarized in Figure 2, over 128 million fewer allowances were sold in Compliance Period 3 at a cost of $1.67 more per allowance as compared to Compliance Period 2. Auction proceeds sent to states participating in RGGI decreased to approximately $901 million during Compliance Period 3, down from $983 million in Compliance Period 2 and $952 million in Compliance Period 1.

Figure 2
Summary of RGGI CO_2-Allowance Auction Results: Clearing Prices and Amounts Offered and Sold



Notes: [1] Clearing prices are weighted averages, based on number of allowances sold. [2] In 2014 and 2015, the Cost Containment Reserve ("CCR") trigger price was exceeded and additional allowances above what were originally offered into the market were ultimately presented and sold to market participants. In 2014, 5 million additional allowances were sold, and in 2015, 10 million additional allowances were sold.
Source: RGGI, Inc., http://www.rggi.org/market/co2_auctions/results.

Prior Analysis Group Reviews of the RGGI Program

Prior Reports on Economic Impacts of RGGI's First & Second Compliance Periods

Analysis Group has previously measured the economic impacts of RGGI's first six years (*i.e.*, Compliance Periods 1 and 2). Our 2011 and 2015 Reports presented the results of our analysis,

[24] See "RGGI States Announce Proposed Program Changes," August 23, 2017, https://rggi.org/sites/default/files/Uploads/Program-Review/8-23-2017/Announcement_Proposed_Program_Changes.pdf.

which led us to make the following observations about the RGGI experience with respect to Compliance Periods 1 and 2:

- *Mandatory, market-based carbon control mechanisms are functioning properly and can deliver positive economic benefits.* During the initial six years of experience with RGGI, the pricing of carbon in Northeast and Mid-Atlantic electricity markets was seamless from an operational point of view, and generated economic value added to the RGGI region of roughly $1.6 billion and $1.3 billion, respectively, in each of the two compliance periods.[25]
- *The RGGI Model has successfully achieved CO_2 reductions through a cooperative framework that preserves state authority*. The states that comprise the RGGI region are highly diverse, including politically and in their state policies, and have continued to change over the course of the RGGI program. Despite these differences, the RGGI states have successfully navigated the complications that can arise from efforts to coordinate regulatory and policy objectives across state lines. RGGI confirms the possibility that states can work together, particularly when doing so is likely to lower compliance costs and generate economic benefits.
- *The states used CO_2 allowance proceeds creatively – supporting diverse policy and economic outcomes.* The states' use of allowance proceeds not only provides economic benefits, but also has helped them meet a wide variety of social, fiscal, and environmental policy goals.
- *RGGI reduces the region's payments for out-of-state fossil fuels.* RGGI helped to lower the total dollars these states sent outside their region in the form of payments for fuel, as the fuels that power the region's fossil-fueled generators come from outside the region. Implementation of RGGI and the use of auction proceeds for EE and RE power production, through reducing generation and shifting the generation mix towards non-fossil resources, reduces the flow of dollars that essentially pay for fossil fuels used in power production in the RGGI states.
- *The design of the CO_2 market in the RGGI states affected the size, character, and distribution of public benefits.* The joint decision by the RGGI states to make their CO_2 allowances available to the market through a unified auction generates substantial revenues for public use. This approach transferred emissions rights from the public sector to the private sector at a monetary cost (rather than transferring them for free). Had these allowances been given away for free, the states would not have had the benefit of the auction proceeds and instead would have transferred that economic value to owners of power plants.
- *How allowance proceeds are used has affected their economic impacts.* The RGGI states used their RGGI allowance proceeds very differently, in ways that affect the net benefits within the electric sector and in the larger state economy. From a strictly economic perspective, some uses of proceeds clearly deliver economic returns more readily and substantially than others. For example, RGGI-funded expenditures on EE depress regional electrical demand, power prices, and consumer payments for electricity. This benefits all consumers through downward

[25] Given the vintages of those prior studies, all Compliance Period 1 results are reported in 2011 dollars (as described in our 2011 report), while all Compliance Period 2 results are in 2015 dollars (as described in our 2015 report). The results are presented on a net present value basis using a public discount rate of 3 percent. For additional results see the AG 2011 and AG 2015 Reports.

pressure on wholesale prices, even as it particularly benefits those consumers that actually take advantage of such programs, implement EE measures, and lower both their overall energy use and monthly energy bills. These savings stay in the pockets of electricity users directly. But there are also positive macroeconomic impacts as well: the lower energy costs flow through the economy as collateral reductions in natural gas and oil in buildings and increased consumer disposable income (from fewer dollars spent on energy bills), lower payments to out-of-state energy suppliers, and increased local spending or savings. Consequently, there are multiple ways that investments in EE lead to positive economic impacts; this reinvestment thus stands out as the most economically beneficial use of RGGI dollars. Other uses also provide macroeconomic benefits, even if they do not show up in the consumers' pockets in the form of lower energy bills.

- *States have demonstrated the capability to manage RGGI program costs and benefits in a way that is fair and protects low-income customers.* The RGGI states have done this by focusing both public policy objectives and normal ratemaking practices on fair outcomes when considering how to invest RGGI proceeds. Proceeds spent on direct customer bill assistance and EE programs targeted to low-income populations, for example, achieve these goals. Market-based mechanisms, such as RGGI, also offer unique opportunities to minimize overall social costs while reducing CO_2 emissions, by providing flexibility in how reductions are achieved, which ensures the lowest possible cost to consumers.
- *RGGI produced new jobs.* Taking into account consumer gains, power plant owners' losses, and net positive economic impacts, RGGI implementation led to overall job increases, estimated to be between 14,000-16,000 job-years in both Compliance Periods 1 and 2.
- *Timing differences in program costs versus benefits affects results.* Positive economic impacts associated with the distribution and spending of allowance proceeds tend to lag cost incurrence (and price impacts) by a year or more in many states. States can improve economic impacts by ensuring quick and efficient use of allowance revenues.
- *Value added in the economy for states' funding of various programs strongly outweighs the direct and induced effects of power-generator revenue loss.* RGGI's impacts affect many part of states' economies. RGGI proceeds were spent on economic activities affecting the electric sector, other energy uses (*e.g.*, natural gas use in buildings), support for low-income residents to meet their energy bills, educational activities, and general fund support. The positive economic multipliers associated with these expenditures contributed to net positive effects of the program in the RGGI states. On an NPV basis, these gains are larger than the direct impacts on the electric sector, where there were net positive electric consumer impacts but net revenue losses to power plant owners.
- *A region's pre-existing generating mix affects economic impacts.* Since power generation resources have different CO_2 emission impacts – with coal-fired generation having higher combustion-related CO_2 emissions than other electricity generating resources – the amount of coal in a particular state's generating mix affects the costs of the RGGI program.

2017 Report on Voluntary Cooperation on Allowance Trading Among States

A July 2017 Analysis Group report entitled "RGGI and Emission Allowance Trading, Summer 2017 Update"[26] reviewed the rationale and potential mechanisms for expansion of emission-allowance trading opportunities between sources in RGGI states and in other states that might be considering participation in or otherwise linking to the RGGI program and trading platform. This issue remains relevant, in light of Virginia moving forward with legislative priorities to participate with RGGI states, and New Jersey recently issuing an executive order to reinstate its prior participation in RGGI.[27] Moreover, the RGGI states have indicated their willingness to engage in discussions with other states – and, in particular, with Virginia and New Jersey – that may want to participate in RGGI in whole or in part.[28]

The AG 2017 Report reviewed the possibility of expanded CO_2-allowance trading among states, and considered the various design features that could accompany an expanded trading platform. In particular, this study considered the rationale for maximizing the size of the trading region, noting that a "…tradeable-allowance structure operates well in both regulated and competitive electric-industry contexts and integrates seamlessly with electricity market operations…[and] a broader trading market with more participants creates the opportunity to lower overall costs of compliance."[29] That report noted that while expanding RGGI to include other states might affect the level of state auction revenues (since, all else equal, expanding the compliance footprint should lower the marginal cost of CO_2 control and thus lower the price of auctioned allowances), this potential effect is part of a program that achieves the longer-run benefits of a broader allowance trading footprint.[30]

Finally, the AG 2017 Report identified and reviewed a set of key emission-allowance trading considerations and specific allowance-trading design considerations, which we summarize here in Tables 1 and 2.[31]

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[26] Paul Hibbard and Ellery Berk, "RGGI and Emission Allowance Trading, Summer 2017 Update," July 2017 (hereafter "AG 2017 Report") (available at http://www.analysisgroup.com/uploadedfiles/content/news_and_events/news/ag_white_paper_rggi_trading_july_2017.pdf).

[27] See http://www.nj.gov/governor/news/news/562018/approved/20180129a_eo.shtml and https://governor.virginia.gov/newsroom/newsarticle?articleId=22095, accessed April 4, 2018.

[28] "This auction underscores how RGGI participation helps our states to reinvest in a cleaner and more resilient energy system. Recently, new states have become interested in participating in our program and sharing these benefits," said Ben Grumbles, Secretary of the Maryland Department of the Environment and Chair of the RGGI, Inc. Board of Directors. "The RGGI states are eager to share information about our program with any state that is interested, and especially look forward to further discussions with Virginia and New Jersey." (See https://rggi.org/sites/default/files/Uploads/Auction-Materials/39/PR031618_Auction39.pdf)

[29] AG 2017 Report, page 2.

[30] AG 2017 Report, page 2.

[31] Tables reproduced from AG 2017 Report, pages 3 and 7.

Table 1: Key Emission-Allowance Trading Considerations

Threshold Issue	Description	Key Considerations
Larger Trading Region	RGGI is a nine-state program with a large share of the U.S. economy with demonstrated ability to reduce CO_2 emissions in the affected region. Additional states' participation in RGGI states is likely to achieve additional cost-effective control of carbon emissions from the power plants.	Emission-control programs based on allowance trading in the broadest possible region support least-cost compliance and provide appropriate signals to market participants for infrastructure investment and power plant operation. Broader trading also reduces the likelihood of market monopoly or illiquid trading. Expanded trading may impact auction revenues to RGGI states as a short-term effect of a longer-term reduction in emission-control compliance costs.
The Importance of Regional Trading Considerations and External Collaboration	RGGI is uniquely positioned to support the expansion of a multi-state CO_2 trading market in the U.S.	RGGI is a flexible program that provides for low-cost CO_2-emissions reduction that could benefit from trading emissions across an expanded geographic region. RGGI states' decisions about key program designs and trading rules can affect other states' decisions about whether to join this program.
Auction Revenue Considerations	RGGI initially disburses almost all carbon allowances into the market through a central auction, and returns auction revenues to state governments. The states use those revenues to further GHG-emission reduction goals. Expanded trading may reduce auction revenues because allowance prices would likely fall with broader trading.	The RGGI states have effectively used auction revenues to further CO_2-emission-reduction and EE goals, among other uses. Although broader trading could improve overall efficiency of carbon-reduction approaches, it could also reduce revenues to RGGI states as a result of lowered allowance prices. While short-term revenues may fall, the long-term efficiencies and cost decreases of broader trading will likely outweigh the impacts of short-term revenue reductions.

Table 2: Specific Market-Based Carbon-Control Program-Design Considerations

Threshold Issue	Description	Key Considerations
Program Structure and Minimum Requirements	RGGI operates according to a core set of compliance and reporting obligations established in the MOU and the Model Rule, and according to state regulations. RGGI will likely need to establish a set of similar requirements for non-RGGI trading partners.	Key considerations related to program structure and minimum requirements for additional participants in the program include the emissions caps that trading partners adopt, the sources covered under CO_2 regulation, the method of disbursing allowances, and emissions-reporting and compliance guidelines.
Allowance Comparability	The RGGI states have achieved substantial reductions in regional CO_2 emissions over time, resulting in increasing allowance values. RGGI also employs a CCR and price floor and is considering an ECR.	In considering how to ensure fungibility of CO_2 allowances across trading regions, RGGI states need to consider whether and how to require other new states (that seek to join and/or link up with the RGGI trading program) to set CO_2 caps that match the stringency of the current RGGI cap, and whether to require that trading partners abide by price floors and have their own CCR and ECR reserves are issues. To facilitate broader trading regions, RGGI could proactively identify a strategy for setting comparable emissions caps and therefore creating fungible allowances with new trading partners.
Allowance Distribution	RGGI does not dictate how allowances are initially distributed, although RGGI recommends that states reserve at least a portion of allowances for public purposes. In practice, nearly all RGGI allowances are distributed initially through a central auction.	Initial disbursement of allowances does not affect the value or "opportunity cost" of allowances in the market, and thus does not affect the aggregate cost of compliance or the price of electricity generation. Thus, there is little reason to condition trading on the distribution of allowances. The method of distributing allowance into the market does, however, affect who gets the value of the allowances, with some approaches (*e.g.*, free distribution) potentially leading to potential "windfalls" to particular entities while other approaches (*e.g.*, auctions) retaining value for the public.
Emission Allowance Tracking	RGGI uses a standardized system to track the creation, trading, and retirement of emissions allowances.	RGGI could allow non-RGGI trading partners to participate in RGGI allowance auctions and in the secondary markets, tracking their activity through RGGI CO_2 Allowance Tracking System (COATS), or RGGI could require partner states to demonstrate substantial equivalence between other tracking programs and COATS.
Market Monitoring	RGGI requires careful monitoring of the allowance market to guard against hoarding and other forms of market manipulation.	RGGI's market monitoring has provided a great deal of comfort to states in the program that the program performs well as a market-based approach. Such oversight of market activities is arguably more important with broader trading regions and more market participants. RGGI may want to consider conditioning any new state partnerships upon those states relying on some form of market oversight or assurance mechanism.

Observations from the Implementation of RGGI to Date (2009-2017)

Based on these several studies, we observe that well-designed CO_2 pollution control programs (1) can operate with modest impacts on electricity rates in the first instance, and (2) can produce long-term benefits in the form of lower electricity bills and positive economic value to state and regional economies. A multi-state approach to carbon control can integrate seamlessly into the reliable performance of electric systems and can lead to efficient price signals affecting power plant dispatch, reducing emissions, and providing opportunities for cost-effective compliance costs for producers, to the benefit of consumers.

RGGI's success in producing these outcomes can in part be attributed to many program design and implementation features:

- *Program design and revision process* – The initial RGGI design and the subsequent revisions adopted by the RGGI states in 2013 (under the Updated Model Rule) occurred through collaborative processes involving a diverse set of states and other stakeholders. Participation included representatives not only from state agencies, but also from industry, environmental groups, experts and think tanks, and other organizations. Each state that elected to join RGGI obtained authority to do so through its legislature and/or regulatory mechanisms (as appropriate in each state). RGGI developed a 'model rule' that outlined the core design elements of the program, and then each state adopted its own enabling authority to allow it to participate. This meant that the participating states did not need to adopt a formal interstate compact under federal law, while still allowing the participating states to establish a coordinated and common mechanism for incorporating a carbon price into their power-system dispatch and operations;
- *Careful attention to policy design* – The process leading up to RGGI's initial design and subsequent implementation and revisions over time took care to address various elements of the program: establishing emission limits and allocation approaches; establishing processes to auction allowances; allowing for the free trade of allowances subsequent to their initial movement into the market; establishing periodic demonstrations of compliance; and allowing flexibility for states to use auction revenues in a manner consistent with their own policy objectives;
- *Common auction and trading platforms* – Ultimately, each RGGI state voluntarily decided to distribute the vast majority of its CO_2 emission allowances through a common, centralized auction administered by the organization (RGGI, Inc.) set up by states to run the program. This centralized administration and tracking of allowance ownership (which allowed for allowances to change hands subsequent to the initial auction) provides participating RGGI states with ease of implementation, allows for shared governance, and supports effective and efficient monitoring of a single allowance trading market; and
- *State allowance revenue decisions* – The use of auction proceeds has varied across the states and over time, consistent with agreements among the states and with each state's enabling authority. In practice, however, the majority of RGGI auction proceeds have been reinvested in EE and RE projects in part reflecting the states' interest in mitigating the impact of the program on wholesale electricity prices and consumer electricity costs. This practice is the source of many of the electricity and economic benefits we find in our analysis.

Comparability of Different Studies of RGGI Program Impacts

The methods used in this Report's analysis are solely focused on measures of *economic* impacts. They trace the dollars collected through the RGGI auctions and measure the full range of economic impacts in the electric markets and on states' economies that result from state spending of RGGI's CO_2 allowance auction proceeds. The results reflect a comparison of a world with and without these RGGI-related effects, holding all else equal. This approach does not take into account other potential measures of economic benefits (such as climate risk mitigation and air quality or other human health and environmental impacts), and thus differs from other studies of RGGI's impacts in this regard.

For example, RGGI, Inc. has developed reports reviewing the impacts of the use of RGGI auction proceeds in 2014 and 2015 ("Benefits Studies"). These reports differ from our study in a number of important ways, including:

- The Benefits Studies focused on the community-level impacts (*e.g.*, the number of participating households and businesses, energy bill savings, and the number of workers trained) of how RGGI dollars are spent locally.
- The Benefits Studies characterize the magnitude of potential environmental benefits by estimating and reporting CO_2 emissions avoided, equivalence to other mitigation actions (*e.g.*, taking cars off the road), MWh saved, and MMBtu saved;
- The Benefits Studies evaluate impacts in aggregate over the full course of RGGI program administration (as opposed to a single Compliance Period), and report impacts by investment categories (*e.g.*, EE, Clean and Renewable Energy, GHG Abatement);
- The Benefits Studies do not attempt to capture power-system dispatch impacts or induced impacts on RGGI states' economies.

Such differences between the Benefits Studies and our analysis make it difficult (if not inappropriate) to directly compare their results. Similarly, the methods applied in other independent reports are not comparable to the focus or analytic approach here. Each study has its own objectives and methods, applies varied analytic approaches, model platforms, and/or timeframes, and seeks to inform a different set of questions. It is important to understand these distinct elements when comparing results across studies.

3. PURPOSE AND METHOD FOR THE ANALYSIS OF COMPLIANCE PERIOD 3

Overview

From 2015 through 2017 (*i.e.*, Compliance Period 3), the auction of RGGI CO_2 emission allowances has resulted in the collection and disbursement to states of approximately $901 million. (See Figure 1) This Compliance Period 3 revenue is slightly less than the amounts collected in prior Compliance Periods: $952 million collected in Compliance Period 1 (2009-2011) and $983 million collected in Compliance Period 2 (2012-2014).[32]

Consistent with how we conducted our assessments in our AG 2011 and 2015 Reports, our analysis of Compliance Period 3 follows the allowance auction revenues and identifies the economic impacts of its use. Namely, we track the path of RGGI-related dollars as they leave the pockets of power plant owners who buy CO_2 allowances to demonstrate compliance, show up in electricity prices and customer bills, make their way into state expenditure accounts, and then roll out into the economy in one way or another. This analysis focuses on the actual impacts of verifiable economic activity: known CO_2 allowance prices as reflected in actual auction prices over time; observable CO_2 allowance auction proceeds (nearly $901 million in Compliance Period 3); dollars distributed to the RGGI states as a result of each auction; actual state-government decisions about how to spend the allowance proceeds; measurable reductions in energy use from EE programs funded by RGGI dollars; traceable impacts of such expenditures on prices within the power sector; and concrete economic activity and value added to the states' economies. By carefully examining the states' implementation of RGGI to date, based on real data about expenditures inside and outside of the electric sector and our calculation of value added from RGGI program implementation, we track the extent to which RGGI program implementation represents a positive or negative impact on the economies of the RGGI states.

There are four major elements of our review, each of which is discussed in more detail in the sections that follow:

1. We first established the **scope and overall framework of the analysis**, to create an integrated analytic framework that separates and highlights RGGI state impacts based on known historical program implementation data (*i.e.*, during Compliance Period 3), from other factors and impacts outside the region or associated with forecasts or projections. This scope of analysis thus included modeling of actual funds received and spent by the states, and actual impacts on electricity markets, as well as an assessment of the impacts of RGGI program expenditures on the larger economy.
2. Next we conducted a thorough review of **data and information on each state's use of revenues collected from the sale of RGGI allowances**. We initially received data from RGGI detailing each state's programs that received RGGI funding, and how much RGGI funding each program received in each year of Compliance Period 3. We supplemented this

[32] The dollars reported here are in nominal dollars. For comparison purposes, we have converted these amounts into real dollars (2018$), by inflating them based on the Consumer Price Index. With these conversions into real dollars (2018$), Compliance Period 1 proceeds amounted to $1.08 billion, Compliance Period 2 proceeds were $1.05 billion and Compliance Period 3 proceeds totaled $0.94 billion.

information as needed by researching individual programs to understand the specific activities that were being funded, and by relying in some instances on the work done in our prior studies. The purpose of this step was to track how RGGI revenues were disbursed (from RGGI, Inc. to the states) as a result of auctions occurring during Compliance Period 3, how disbursed funds were used by the states, and what impacts resulted from associated program implementation. Part of this analysis resulted in information about the use of allowance proceeds that affected activity in the electric sector (*e.g.*, how expenditures on EE programs affected the level of energy use in various portions of the day and in different seasons of the year) and in other parts of the economy (*e.g.*, how different program expenditures provided job training, or purchases of equipment, as described further below).

3. Third, we modeled **electric sector outcomes** from both the incurrence of increased costs associated with affected facilities' compliance obligations (namely, the purchase of allowances and changes in the electric supply offers and wholesale market clearing prices consistent with those CO_2 allowance costs), and the effect of changes in electric generation and demand associated with the use of funds to spur investment in EE and advanced energy technologies. Our electric sector analysis was conducted using the PROMOD model.[33]
4. Fourth, we modeled **macroeconomic outcomes**, combining electric sector outcomes – positive and negative – with expenditures in all sectors of the economy associated with the use of RGGI funds in the nine states. This produced an overall picture of how RGGI program implementation has affected the economy, including multiplier effects associated with the impacts on consumer electricity payments, power plant owners' costs and revenues, and the flow of RGGI-related dollars through other sectors of the economy. Our macroeconomic analysis was conducted using the IMPLAN model.[34]

It is clear from our program research and results that different investment portfolios by states resulted in different impacts from both economic and non-economic perspectives. Because our analysis focuses only on economic impacts, it does not shed light on the core objectives of the RGGI program – namely, addressing the economic, social, health and environmental risks associated with climate change, health benefits associated with ancillary reductions in other pollutants, or reduced health and environmental impacts associated with other effects of fossil-fuel generation. While we recognize that these were the key motivators of states acting to control emissions of CO_2, our focus was more narrowly on the economic (monetized) impacts of RGGI program implementation.

[33] The PROMOD model and our analysis of electric sector impacts are described in detail in the Appendix of this Report. Note that PROMOD allowed for estimation of electric-energy market impacts while capacity-market impacts were calculated separately.

[34] The IMPLAN model and our analysis of macroeconomic impacts are described in detail in the Appendix of this Report.

Scope of Analysis

Overview

To carry out our analysis of economic impacts of RGGI, we ran power-system dispatch models and macroeconomic models under two scenarios: the "RGGI case," which is effectively the world as it actually occurred during Compliance Period 3; and the counterfactual "no-RGGI case," which involves changes to model inputs and assumptions to create conditions depicting a world in which the RGGI program had not been in place as of the beginning of 2015. The difference in economic impacts between the two cases reflects RGGI's incremental impacts during Compliance Period 3.

In constructing the scope of our analysis, we were guided by three key objectives: first, we wanted to focus on impacts only within the RGGI states (the geographic perspective). Second, we wanted to identify near-term and longer-term impacts associated only with RGGI's implementation during Compliance Period 3 (2015-2017) (the temporal perspective). Third, we wanted results that were grounded as much as feasible in actual, known expenditures, programs, and impacts (the empirical perspective).

From a geographic perspective, we focused our analyses on the activities and impacts exclusively within the RGGI states. While some money from RGGI spending that flows outside of the RGGI states affects the economies of states outside the RGGI region (for example, for the manufacture of light bulbs or insulation used in energy efficiency programs, or flows of dollars to the federal government associated with changes in income), we did not try to report those out-of-region impacts in our analysis. Similarly, in the power-system modeling, our evaluation of impacts on power plant owners (also referred to as producers or generators here) and energy consumers was limited to those groups located within RGGI states.

From a temporal perspective, we focused our analysis on the third RGGI Compliance Period. We isolated the impacts of RGGI-related dollars associated with Compliance Period 3 only (2015-2017). This means that we included in power pricing the cost to power producers of obtaining RGGI allowances in the third three years of the program, and we included in power and economic sectoral investments only RGGI revenues that were spent during the third three years of the program.

Focusing on these three years of RGGI dollars, we tracked actual dollars collected from power producers during the 12 auctions that have occurred during Compliance Period 3, taking place from March 2015 through December 2017. The funds from these auctions flowed to the states immediately, with states spending them (or programming them for later expenditures, or spending previously collected dollars) during the 2015-2017 time period. Within the electric system, the impacts of these initial auctions also show up during the 2015-2017 period, as power plant owners priced the value of CO_2 allowances into prices they offer in regional wholesale markets. The macroeconomic impacts occur over the time period that allowance proceeds are collected and spent (2015-2017), but there are longer-term effects associated with the imprint of EE and RE project expenditures made during that period on energy use for the following decade (through 2027[35]). We

[35] As described in more detail later in this report, we assume a ten-year lifetime for installed EE measures and RE projects and conservatively truncate our modeling period after 10 years despite these resources having impacts (in the case of EE) and useful lives (in the case of RE) beyond then.

thus track these direct effects of RGGI to date in the near term (*i.e.*, Compliance Period 3), and in the long term track secondary impacts from expenditure of RGGI dollars by the states (for EE-related expenditures from 2015-2017, and from the implications of those EE measures on electricity use from 2015-2027).

From the perspective of modeling data and assumptions, we focus our analysis on known quantities associated with actual results from the third three years of the program. That is, we do not forecast allowance prices; we use actual allowance prices as they revealed themselves through the auctions. We do not estimate future program revenues, since we were focused on actual RGGI auction proceeds to date. We do not project how future revenues will be spent by states, since we rely entirely upon how the states have actually decided to spend allowance proceeds received to date. We make no assumptions about states' participation in RGGI going forward. Nor do we project impacts associated with programs funded through RGGI dollars collected in future years.

The goal of our analysis is thus to identify those incremental economic impacts associated with implementation of RGGI during Compliance Period 3: known allowance prices and revenues; known distribution of revenues to states; actual or committed expenditures associated with state proceeds; and observable impacts associated with RGGI-funded program implementation. In this sense, our analysis should be viewed as a snapshot of impacts associated with a finite period – Compliance Period 3 – of RGGI program administration, and not a projection or forecast of how RGGI may, could or should evolve.

To accomplish our goal, however, we had to establish what these programs meant from an economic perspective, in order to create the "no-RGGI" counterfactual case, against which we compare the actual economic outcomes during the 2015-2017 time period (which included RGGI).

Data Collection and Processing

Overview

Our analysis began with the collection and processing of data related to RGGI program implementation in each of the nine states. Identifying and tracking the use of RGGI proceeds is fundamental to our analysis, and has been facilitated by states' reporting of their expenditures to RGGI, Inc. on a quarterly basis. This process also involved the translating of expenditures on EE measures and new RE projects into impacts on power-system energy consumption and electricity peak loads in various seasons and days of the year.

In the end, we were able to obtain most of the necessary data from the information reported to and by RGGI, Inc. Where information was missing or incomplete, we took successively deeper steps to fill in data gaps, sort out inconsistencies, establish proxy values, and/or arrive at a workably complete data set for use in the study.

Data Gathering

Approach

The first anchor point for our data analysis is the level of revenues collected through the quarterly auctions of allowances (approximately $901 million) during Compliance Period 3. We collected data on the sales of allowances into the market and on the allocation of those auction revenues to states. Total revenue allocations to states are shown in Figure 1.

Participating RGGI states report their spending of RGGI proceeds to RGGI, Inc. on a quarterly basis. RGGI, Inc. publishes these data and breaks expenditures down into the following seven investment categories: EE, clean and renewable energy, GHG abatement, direct bill assistance, administration, RGGI, Inc. administration, and transfers to the general fund.

Using these data, we traced and categorized in detail the actual use of RGGI auction proceeds for funding to various types activities, and identified the effects of the funded activities, programs, and investments. By "effects" we mean the tangible results of the expenditures that are significant or important from the standpoint of measuring power system dispatch and economic impact through the PROMOD and IMPLAN modeling effort. For example, what are the annual household electricity savings, on- and off-peak, associated with specific EE measures? How many MWh of generation will flow annually from an installed solar photovoltaic ("PV") systems using RGGI dollars? Identifying such effects involved (1) collecting data and estimates by RGGI, Inc. on such effects, and (2) applying best-practice estimation methods where data across states were missing, incomplete or inconsistent.

Process

Our process for cataloguing the collection, allocation, disbursement, and use of RGGI allowance revenues involved three basic steps:

- We first collected and reviewed data on expenditures of RGGI auction proceeds and on the estimated effects of RGGI-funded programs from public sources. The public sources of information included publicly available reports on RGGI and/or separately on state energy efficiency programs.
- Using the existing data, we organized it to format the data for input into the PROMOD and IMPLAN models.

Based on our review of the data, the similarities in spending vehicles across RGGI states, and the levels of disaggregation needed for model inputs, we divided program spending into seven categories. These categories are described below, and expenditures by category for each electric market region (New England, New York, and PJM RGGI states), as well as for the entire RGGI footprint, are presented in Table 2 and Figure 3, below.

1) *Energy Efficiency and Other Utility Programs* – Because much of the RGGI funds were spent on EE measures, and because different measures lead to different impacts on consumers' demand for electricity, we grouped information on EE programs into residential retrofit/new construction and commercial retrofit/new construction categories.

2) *Renewable Investment* – This includes grants to programs and investments focused on the development, distribution, and installation of renewable or advanced energy technologies. We assume that this investment was largely supporting solar PV installations.

3) *Education and Job Training* – This includes monies used for programs (i) to educate business and residential consumers about energy consumption and the availability of programs to reduce consumption, and (ii) train workers with new skills and knowledge in industries and activities that contribute to lowering energy use (*e.g.*, installation of EE measures) or the production and distribution of renewable or other advanced energy technologies.

4) *Clean Technology Research/Development* – This includes grants and other funding to support research or other public/private groups focused on the furthering R&D related to GHG emissions (*e.g.*, clean technologies, alternative transportation, carbon sequestration).

5) *Direct Energy Bill Assistance* – This includes use of RGGI funds to provide payment credits or other means to reduce bills paid by consumers for electricity and heating/cooling. In some cases, investments in this category are targeted to low-income households.

6) *GHG Reduction Programs* – The GHG reduction programs include a variety of expenditures aimed at reducing GHG emissions (*e.g.*, R&D grants for CO_2- emission abatement technologies, direct investment in "green" start-up companies, efforts to reduce vehicle miles traveled, climate change adaption measures, investments in existing fossil-fuel fired power plants to make them cleaner and/or more efficient).

7) *Program Administration* – RGGI Program Administration refers to RGGI auction proceeds used by each RGGI state to cover costs associated with the administration of the state's CO_2 Budget Trading Program and/or related consumer benefit programs.

The amounts of funds spent by program category (by RGGI state, by electrical region for the RGGI states and for the nine-state RGGI region as a whole) are show in Table 3 and Figure 3, below.[36]

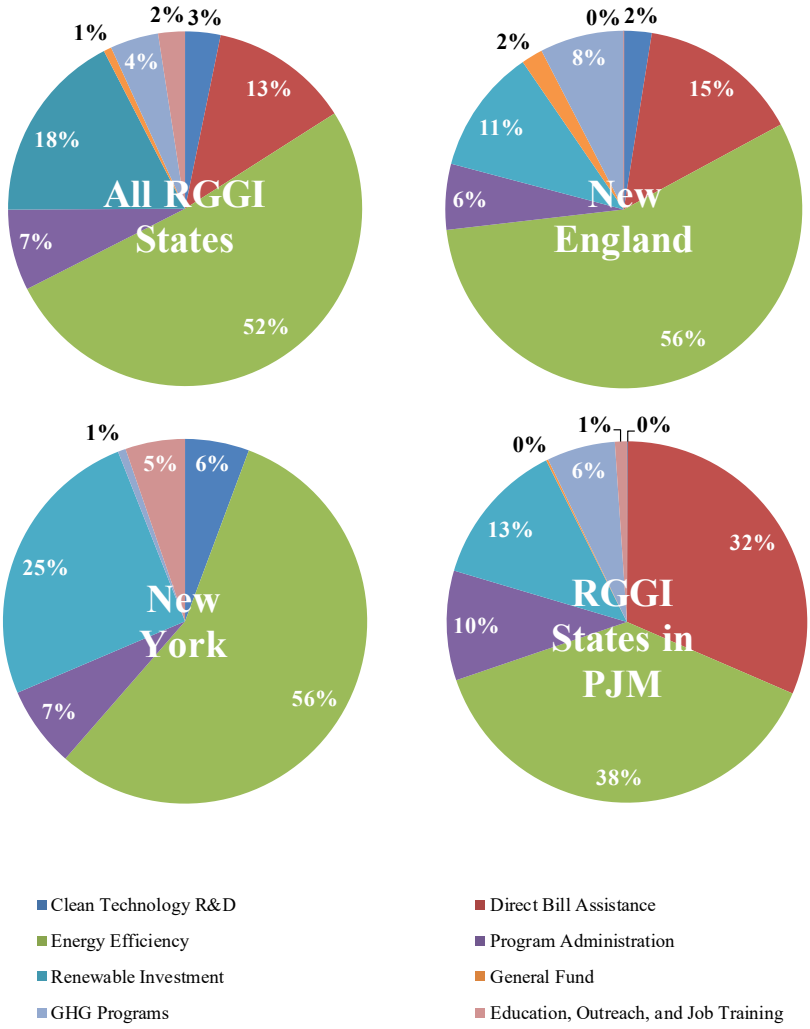
[36] Between 2015 and 2017, the RGGI states spent more on RGGI-related programs than the revenues collected during Compliance Period 3 auctions. The analysis presented in this study models the full amount of state spending on RGGI programs during this period.

Table 3
Spending of RGGI Proceeds by Category and by State, Electrical Region and RGGI Region
Compliance Period 3 (in $ millions)

	Energy Efficiency	Clean Technology R&D	Direct Bill Assistance	GHG Programs	Program Administration	Renewable Investment	Education, Outreach, and Job Training	General Fund	**Total**
Connecticut	41.7	-	-	-	4.1	25.4	-	7.0	**78.3**
Maine	30.3	0.2	6.6	-	1.6	-	-	0.5	**39.2**
Massachusetts	114.0	9.1	-	28.9	12.2	12.9	-	-	**177.1**
New Hampshire	9.7	-	39.9	-	1.0	-	-	-	**50.5**
Rhode Island	10.7	0.3	9.2	0.1	3.4	4.9	0.0	-	**28.8**
Vermont	7.5	-	-	-	0.4	-	-	-	**7.9**
New England Subtotal	**214.0**	**9.6**	**55.7**	**29.1**	**22.7**	**43.2**	**0.0**	**7.5**	**381.8**
New York	253.4	25.9	-	3.2	32.6	115.5	24.1	-	**454.8**
New York Subtotal	**253.4**	**25.9**	**-**	**3.2**	**32.6**	**115.5**	**24.1**	**-**	**454.8**
Delaware	38.1	-	2.3	0.1	6.5	13.9	-	0.5	**61.3**
Maryland	66.7	0.2	83.6	16.7	20.4	21.7	2.9	-	**212.3**
RGGI States in PJM Sub	**104.8**	**0.2**	**85.9**	**16.8**	**26.9**	**35.6**	**2.9**	**0.5**	**273.6**
All RGGI States	**572.2**	**35.8**	**141.6**	**49.0**	**82.2**	**194.3**	**27.1**	**8.0**	**1,110.2**

Source: Analysis of state-level proceeds spending data reported to RGGI, Inc.

Figure 3
Summary of RGGI Proceed Spending by Region



Source: Analysis of state-level proceeds spending data reported to RGGI, Inc.

Modeling Approach

Overview

Since our goal was to track the incremental impact on the economy resulting from the purchase and use of RGGI allowances and from the states' use of those RGGI allowance proceeds during Compliance Period 3, we needed to (1) construct a counterfactual electric system that did not reflect RGGI impacts and (2) develop an analysis that followed the flow of RGGI dollars through the economy. We provide the details of our assessment tools in the Appendix of this Report, which describes the IMPLAN and PROMOD models in greater detail.

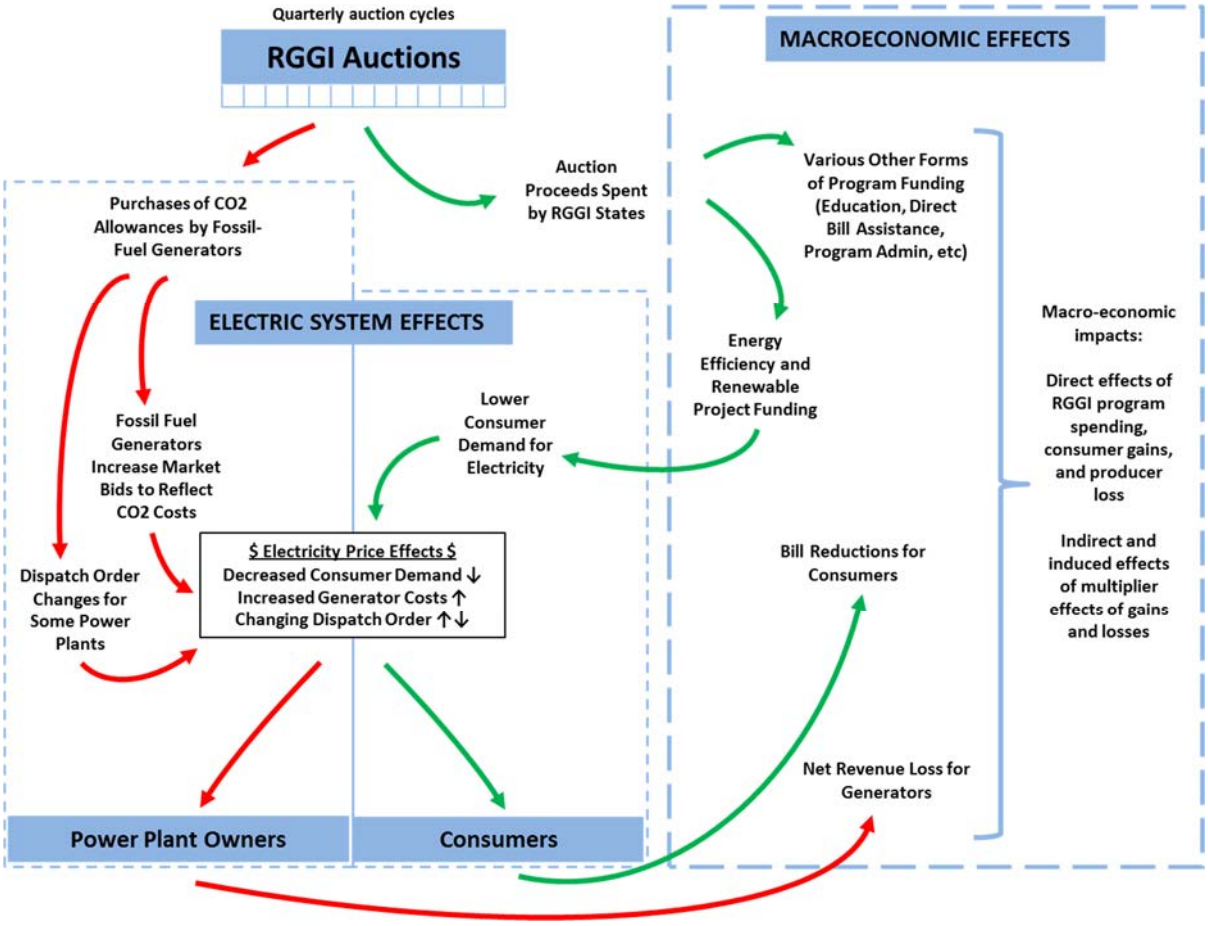
With respect to impacts on the general economy, RGGI allowance proceeds have two effects. First, when the states use RGGI proceeds to fund an activity (such as EE) those monies have a direct impact in the form of purchases of goods and services in the economy. Second, in one way or another, many states reinvest allowance proceeds to affect costs in the power sector (*e.g.*, to facilitate cost-effective reductions in power-sector emissions of CO_2, and/or to mitigate the impact of the RGGI program on consumers' electricity costs). Thus, both the compliance obligation and the use of RGGI proceeds create changes in the power sector, in the form of changes in power plant owners' costs, offer prices bid into wholesale electricity markets, and consumer spending on electricity bills. In aggregate, these changes in spending lead to revenue gains and losses (to power plant owners) and gains and losses (to consumers), which, in turn, affect economic flows in the economy.

To estimate these impacts on the economies of RGGI states, we model changes to the electric system and macroeconomic outcomes. The general flow of data and modeling outcomes is depicted in Figure 4.

Our modeling approach combines analysis of power sector effects (through modeling using PROMOD), and analysis of macroeconomic effects (through use of IMPLAN). The foundation of our modeling analysis is, in effect, a comparison between two scenarios run through the models. In the PROMOD model, we run a dispatch of the regional power systems "with" and "without" RGGI, and include in each run the same core conditions: power system infrastructure both in place and as it evolves over the modeling period (that is, transmission configurations and power plant additions and retirements); local and regional forecasts of electric energy and peak load by service territory over the modeling period; and projections of fuel prices and allowance prices for NO_x and SO_2; and so forth.[37] In the IMPLAN analysis, we start with economic relationships that exist among providers and users of goods and services in the nine RGGI states, and then we introduce the direct expenditures (RGGI proceeds) and the revenue gains and losses to electricity consumers and power producers (from the PROMOD model).

[37] Forecasts of load, fuel and other prices are needed for the period after 2017 to analyze the impact of the energy efficiency and renewable investments made during the 2015-2017 period.

Figure 4
Flow of Data and Modeling Outcomes in our Analysis of RGGI's Impacts on the Electric System and State Economies



The two cases in PROMOD can be described as follows:

- RGGI Scenario – In the RGGI scenario, the power system is modeled as it is. That is, the RGGI case represents the world as it has evolved with RGGI in place and operating as it did during Compliance Period 3. It includes all of the programs, measures, investments, and funding that are associated with the third RGGI compliance period, and all of the impacts on the power system and economy associated with the use of RGGI funds.
- No-RGGI Scenario – In order to create the counterfactual against which we compare and contrast the RGGI case, we create a scenario configured to represent the power system and economy as it would have progressed absent expenditure of RGGI-related dollars in Compliance Period 3. In order to do this, we relied on all of the data and representations of RGGI investments and associated effects described in the previous section, and removed those investments and effects from the RGGI scenario. But for these changes, all elements of the modeling process are identical across cases.

We then traced the dollar differences in these two PROMOD runs (with and without RGGI) through the macroeconomic IMPLAN model to capture the impacts of these electric sector outcomes; we also injected funds related to the states' direct expenditures of RGGI program dollars in IMPLAN.

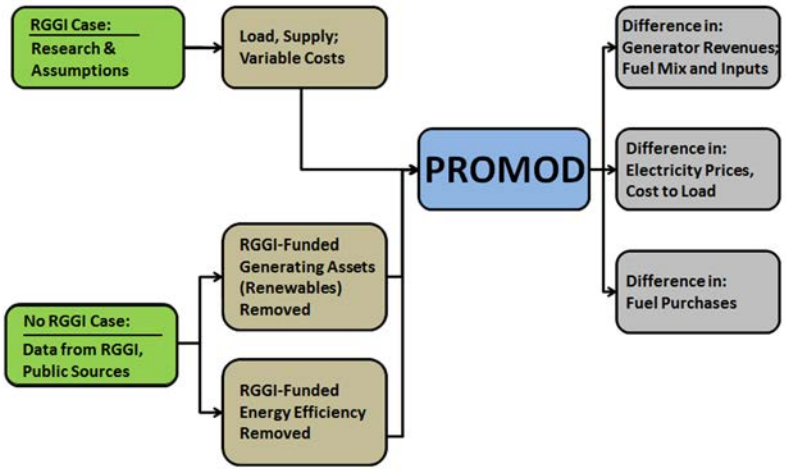
In the following sections, we summarize the power system and macroeconomic models, and highlight a few key factors of the modeling approach that help to interpret the results. More detail is available in the Appendix.

Power Sector Analysis

RGGI has two primary effects in wholesale power markets. First, marginal power prices are at times increased by the additional CO_2 allowance cost to affected (fossil-fired) power generating facilities. Second, demand and marginal prices are at times decreased by the amount and type of EE measures and RE projects installed as a result of spending RGGI allowance proceeds.

Using the PROMOD power system dispatch simulation model, we quantified these net impacts on regional and local electric-system loads, power prices, and revenues to power producers associated with implementation of the RGGI program in the third compliance period. (See the Appendix for a detailed description of the PROMOD modeling platform, the core logic for which is explained briefly below.) These relationships are summarized in Figure 5. Using PROMOD, we created the "with RGGI" case (benchmarking the modeling results to the actual electric output that was observed in 2015-2017) and then constructed a counterfactual "no-RGGI" case. Comparing the results of the two cases provided information about the incremental effect of RGGI's Compliance Period 3 on power system users and producers.

Figure 5
Diagram of PROMOD Modeling Inputs and Outputs for RGGI Impacts on the Electric System



Traditional cost-minimizing strategies in the dispatch of power systems involve use of production-cost information to determine which power plants operate at different times of the day to meet changing load conditions. In competitive wholesale electric market regions like the Northeast and Mid-Atlantic regions, decisions on which power plants to turn on and off are made based primarily on bids submitted by power plant owners indicating the price at which they are willing to supply power

into the markets. Provided the market is sufficiently competitive, price bids should approximate marginal production costs of the facilities in the system. Generally, prices in wholesale markets are set hourly based on the last generating unit dispatched – that is, the most expensive unit that was needed to meet hourly load.

The PROMOD power system model is configured to comprehensively simulate the dispatch of the power system on an hourly level based on power plant marginal costs, subject to various operational and transmission system constraints that can alter dispatch order (and thus prices) in real time. The PROMOD model simulates system dispatch based on, and reflecting: (1) the operational characteristics and marginal production costs of every generating facility in the power region being studied (in this case, New England, New York, and PJM); (2) the configuration of and limits on transfers of power across the transmission system, comprising every transmission line and other system components in place; and (3) algorithms designed to reflect the operational constraints of power plants, such as the time it takes to start units and to ramp them up to various power levels, the minimum time they must be on, and the minimum time they must be off. Given the level of detail in how PROMOD represents the power system – that is, down to very small power plants and specific transmission system components and limits – it is able to simulate and produce power prices, unit output, emissions, costs to loads (*e.g.*, wholesale supply to consumers), producer revenues, and other factors. PROMOD calculates these metrics on an hour-by-hour basis, and with a high degree of geographic resolution (that is, down to a utility's service territory, or a specific substation).

Given this level of detail, we are able to model investments in EE and the development of new generation using RGGI funds at a detailed state- and utility-specific level. This allowed us to capture the impact of such investments on the wholesale prices that consumers pay – and that power producers are paid – on hourly and locational bases. As shown conceptually in Figure 5 above, we simulated the dispatch of the three regional power systems that contain the RGGI states for each hour of the modeling period (January 2015 through December 2027) for both the "with RGGI" and "no-RGGI" cases.[38] Based on the output of those two cases, we calculate changes in (1) unit dispatch, (2) wholesale electric prices, (3) payments to power producers, and (4) payments by consumers.

We used the PROMOD output and associated calculations of changes in generator and consumer prices, revenues, and payments in two ways. First, the data are used to describe the impacts on generators and consumers from the perspective of the electric system only – that is, how much more or less do power plant owners get paid as a result of RGGI program investment effects? How much more or less do consumers pay for electricity as a result of RGGI program investment effects? How does that differ by region? How do these electric system impacts change with time? The impact on power plant owners and consumers associated with the RGGI program – which is focused on the electric sector only – is an important consideration in program design and effectiveness.

Secondly, we use the output data from PROMOD as inputs to the IMPLAN model. From a macroeconomic perspective, the end result of changes in power-system costs, revenues, and payments are (a) changes in economic conditions for power plant owners (affecting their ability to spend and save in the general economy), and (b) changes in the level of disposable income enjoyed by consumers as a result of RGGI's impact on wholesale electricity prices which affects their spending

[38] See the Appendix for more information about PROMOD and the modeling area.

and saving in the general economy. Consequently, changes in these two factors serve as inputs to the general economic model (described below), along with other categories of RGGI program investment.

Macroeconomic Model

As previously noted, changes in power producer revenues and consumer incomes associated with electric-system impacts lead to these larger direct and indirect impacts in the economy as a whole. Other economic impacts also need to be taken into account: those related to the actual direct spending of RGGI auction proceeds by government agencies (and in turn, indirectly by the recipients of the RGGI-funded grants). Additionally, these other impacts result from the multiplier effects of these changes in consumer income and producer revenues and from the purchases of goods and services in the economy by those who receive RGGI-related spending from the states.

Consequently, in order to model macroeconomic impacts, we combine the changed revenues and spending that come from the PROMOD model with all categories of the direct investment of RGGI allowance revenues in the macroeconomic model, IMPLAN. IMPLAN is a social accounting/input-output model that attempts to replicate the structure and functioning of a specific economy (*e.g.*, a state or a country), and is widely used in public and private sector economic impact analyses. It estimates the effects on a regional economy of a change in economic activity by using baseline information capturing the relationships among businesses and consumers in the economy based on historical economic survey data that track flows of money through the economy. IMPLAN tracks dollars spent in a region, including dollars that circulate within it (*e.g.*, transfers of dollars from consumers to producers), dollars that flow into it (*e.g.*, purchases of goods and services from outside the local economy), and dollars that flow outside of it (*e.g.*, payments to the federal government). The model thus examines inflows, outflows, and interactions within the economy under study.

The IMPLAN model allows one to investigate interactions in the RGGI region and the individual states within it, and to calculate various economic impacts in that economy when a new activity (such as investments in EE or use of funds to support a state's general fund or assistance to help consumers pay their energy bills or lost revenues for owners of power plants) involves money flows around the economy. Specifically, the model captures various impacts, including:

- *Employment impacts* (the total number of jobs created or lost);
- *Income impacts* (the total change in income to employees that results from the economic activity); and
- *"Value-added" impacts* (the total economic value added to the economy, which reflects the gross economic output of the area less the cost of the inputs).

Although we report employment impacts of our analysis, we focus primarily on the "value-added" impacts produced by the model, reflecting the combination of the following economic effects of the change in money flow associated with RGGI:

- *Direct effects:* the initial set of inputs that are being introduced into the economy. In our study, these include the direct effects of RGGI on owners of power plants as a whole, on energy consumers (end users of electricity, natural gas and heating oil), and use of RGGI proceeds to buy goods and services in the economy (*e.g.*, investment in EE, work training programs, bill payment assistance for low-income consumers).

- *Indirect effects:* the new demand for local goods, services and jobs that result from the new activity. Examples include the spending on labor to retrofit buildings with EE measures, or to train workers in these skills. Some RGGI auction proceeds lead to payments for things to suppliers located outside the local region (*e.g.*, the purchase of efficient lighting equipment or solar panels manufactured outside of the RGGI region); IMPLAN traces those dollars that do not stay within the local economy when dollars are spent on RGGI-related activities.
- *Induced effects:* the increased spending of workers resulting from income earned from direct and indirect economic activity.

Modeling Factors

To calculate the impacts of RGGI, we needed to make a number of assumptions about the systems and economies that we are studying. These assumptions relate to: (1) the relevant boundaries (*e.g.*, geographic, temporal) of the analysis, (2) the methods for putting dollar flows occurring during different time periods into a common economic framework; (3) key modeling parameters in the power system; and so forth. We highlight a few of these below and explain them further in the Appendix.

Focus on Compliance Period 3

First, the analysis does not specifically control for any RGGI-funded investments in EE or supply before 2015 or after the program's third compliance period. For modeling purposes alone, and in order to isolate the incremental effects only of Compliance Period 3, we made no assumptions about RGGI continuing beyond 2017, nor did we attempt to isolate (and remove) the impacts of RGGI-related activity that occurred during the program's first six years. Further, we do not assume that there is a price on carbon through other regional, state, or federal legislation at any point during the modeling period (through half of 2027). Neither assumption should be interpreted as a judgment or expectation about the likelihood one way or the other of continued RGGI program implementation, or the emergence of a national carbon-pricing regime. Constructing the analysis in this way is specifically intended to allow for focus on the specific incremental impacts of RGGI implementation during Compliance Period 3, holding all else equal.

Timing of Economic Impacts that Affect the Power Sector

The focus on actual expenditures and impacts in only the third three years of program implementation, in combination with the application of a discount rate, ends up highlighting the fact that RGGI benefits lag behind RGGI costs. The costs show up in electric system impacts to wholesale prices immediately, during the first three years of the modeling period (*i.e.*, Compliance Period 3), while the benefits to a certain extent flow to consumers over the entire study period (starting at the beginning of 2015 and then through 2027). Conversely, the benefits flow to owners of power plants early on (when marginal power prices are higher), with outer-year effects diminishing those net positive revenues received during the three years of the third compliance period.

Indeed, there is a lag between the incurrence of costs in the "with RGGI" case and the timeframe in which installation of EE measures funded through RGGI allowance revenues begin to affect demand, supply, and prices in the outer years.

Representation of Energy Efficiency Programs

Given the various uses of RGGI funds for EE, there are two major analytic challenges in the PROMOD modeling effort: First, we needed to determine an assumed duration or lifetime for savings from particular measures (for example, for how long does installation of insulation continue to produce savings?). Second, we needed to develop a way to map annual energy and peak load savings onto estimates of impacts on load in every hour of the year.

In all of the RGGI states where EE programs are in place, there is substantial documentation of estimates of annual energy savings and, in some cases, contributions to reductions in peak loads. There is a long history of EE implementation and measurement and verification efforts to support engineering and statistical estimates of how the installation of a given EE measure actually translates into annual savings, distribution of savings across the hours of the year, and measure lifetimes. A number of entities summarize these figures, and we relied on these data to calculate the lifetime and load-impact characteristics of the various EE programs funded by RGGI dollars.[39]

As part of our AG 2011 Report of RGGI's first compliance period, we reviewed where available (and on a program-by-program and measure-by-measure basis) the estimates of measure lives developed by states and utilities and currently used in programs, based on the past few decades of experience in administering EE programs. We calculated weighted average measure life assumed by states and utilities across the range of measures, and found that virtually all programs have measure lives in excess of ten years; on average, measure lives were 12-13 years. In our modeling, we conservatively truncated measure savings at ten years. Consistent with that approach, we adopted the same ten-year measure life for our analysis of the third compliance period.[40] In some areas of the RGGI region, states have estimated how EE-related savings break down on a seasonal basis (summer or winter) and on a daily basis (on- or off-peak). We used the analysis done in our AG 2011 and 2015 Reports for the same purpose here, using information about specific programs and breakdowns of timing for when savings occurred.[41]

Using these characterizations of EE program impacts, we calculated hourly adjustments to load for each EE program, and in aggregate for all programs used these to adjust hourly load in the PROMOD model.

[39] Specifically, we relied on data from the Northeast Energy Efficiency Partnership's (NEEP) Regional Energy Efficiency Database (REED). (See http://www.neep.org/initiatives/emv-forum/regional-energy-efficiency-database)

[40] For this analysis, we confirmed this assumption using data from NEEP. We found that the weighted average measure life across all RGGI states in 2015 and 2016 was approximately 11 years.

[41] For this analysis, we confirmed this assumption using Energize Connecticut, "Connecticut Program Savings Document: 12th Edition for 2017 Program Years," October 31, 2016, page 313 (available at https://www.energizect.com/sites/default/files/2017%20CT%20Program%20Savings%20Document_Final.pdf).

4. RESULTS

Overview

Focusing exclusively on economic impacts of the RGGI program during Compliance Period 3, our report sheds considerable light on how the cap-and-trade program affects prices in electricity markets and in the economies of the participating states. As noted previously, the report does not address the many other objectives that underpinned the RGGI states' adoption of the program, or economic impacts that flow over time from reducing damages associated with climate change.[42]

The states implemented the RGGI program by distributing virtually all of the CO_2 allowances through quarterly auctions, with auction revenues distributed to states in accordance with the RGGI state budget allocation.[43] This approach had an important impact on program outcomes because it meant, in effect, that the public benefitted by transferring the value of allowances to the market at market prices (rather than for free, as was largely done in other SO_2 and NO_x allowance-trading programs). The public received the benefits associated with the allowance value, through the states' use of auction proceeds to pursue specific energy- and non-energy-related public policies, including providing an opportunity to both address some of the potential cost impacts of RGGI program implementation, and to pursue other key public policy objectives.

RGGI auctions for the Compliance Period 3 generated approximately $901 million. These auction revenues were distributed to (or held by) states in the following amounts:[44]

- $61.8 million for Connecticut
- $43.4 million for Delaware
- $32.2 million for Maine
- $182.7 million for Maryland
- $154.3 million for Massachusetts
- $50.6 million for New Hampshire
- $345.1 million for New York
- $23.9 million for Rhode Island
- $6.9 million for Vermont

(Figure 1 (above) shows the proceeds received in each year by the nine states in each of the three compliance periods.)

These dollars have three types of economic impacts:

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[42] The RGGI States' MOU has a preamble that recognizes the common objectives of the states' own policies "to conserve, improve, and protect their natural resources and environment in order to enhance the health, safety, and welfare of their residents consistent with continued overall economic growth and to maintain a safe and reliable electric power supply system." The MOU also declares a common goal of the states of "reducing our dependence on imported fossil fuels will enhance the region's economy by augmenting the region's energy security and by retaining energy spending and investments in the region…" Additionally, the original RGGI MOU states that delay in addressing GHG emissions will make later investments in mitigation and adaptation more difficult and costly, and that a market-based carbon allowance-trading program will create strong incentives for the development of lower-emitting energy sources and energy efficiency. (MOU, pages 1-2).

[43] Where allowances were not distributed via auction, they were sold directly to affected sources, again retaining the value of the allowances sold for public purpose.

[44] Between 2015 and 2017, the RGGI states spent more on RGGI-related programs than the revenues collected during Compliance Period 3 auctions. The analysis presented in this study models the full amount of state spending on RGGI programs during this period.

1. *Impact on the general economy.* Our "bottom line" finding is that RGGI has produced positive results for the economies of the RGGI states. This finding reflects two primary contributing factors:
   - the direct investment of RGGI allowance auction proceeds in various economic activities); and
   - the *net* impact on two countervailing effects: net losses to power plant owners (in the form of lower revenues over time as a result of RGGI spending), and net gains to electricity consumers (in the form of lower electricity bills over time).

   These economic "value added" impacts flow from both the direct, indirect and induced effects of injecting RGGI dollars into various economic activities.

2. *Impact on the electric system.* Observable electric-sector impacts include overall changes to power plant owner revenue streams (from both increased costs for obtaining and using CO_2 allowances, and from changes in the price and quantity of power sales); and overall changes to payments by electric consumers for the purchase of electricity (resulting from lowering total electricity demand and from changes in market prices).

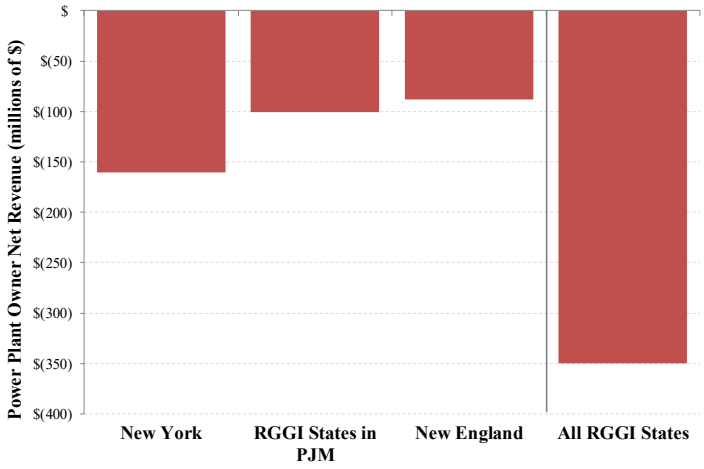
3. *Other effects.* These include changes in employment and payments for fuel that flow from the impacts of the use of RGGI allowance revenues in the electric system and the local economy.

Impacts on the RGGI States Combined

Impact on Electric Producers

From the perspective of the power generation sector, the RGGI program as implemented during the 2015-2017 period led to an overall drop in electric market revenues to owners of generating assets of just less than $350 million (on an NPV basis). Although owners of emitting power plants had to purchase CO_2 allowances, as a group they recovered all of their early expenditures during the 2015-2017 period; in the long run, however, RGGI-driven EE leads to lower sales of electricity than would otherwise occur without RGGI in place and this ends up eroding power plant owners' electric market revenues over time. The net impact to electric power plant owners as a group is summarized by region in Figure 6.

Figure 6
Net Revenue Change Across All Power Plant Owners, by Region, as a Result of RGGI Implementation During the 2015-2017 Period (NPV, 2018$)

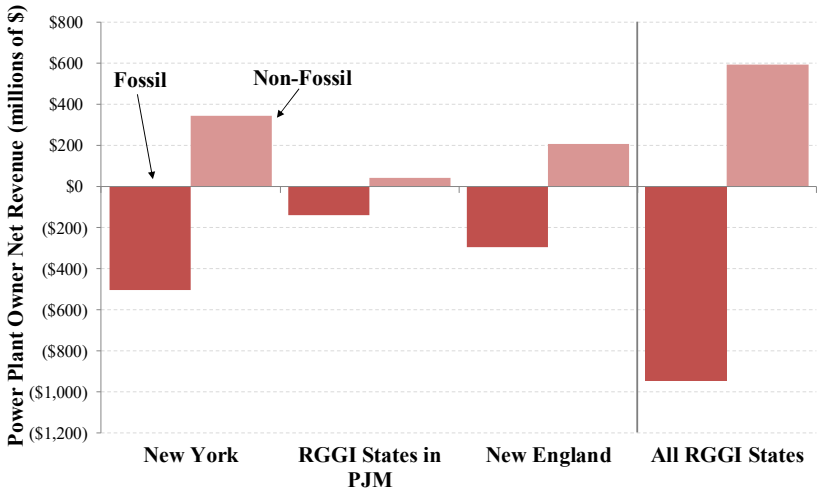


Notes: [1] Figures are reported in 2018 dollars (NPV), converted using a 3-percent discount rate. [2] Figures include PROMOD outputs and capacity market loss calculations calculated separately.

These impacts, however, are not distributed equally across power plant owners. RGGI affords a competitive advantage to power plants with CO_2 emissions lower than their competitors'. In the near term, while owners of emitting resources recover their costs to operate – including the cost of CO_2 allowances – the net effect of the program can reduce profits for owners of plants with relatively high carbon emissions (*e.g.*, coal-fired power plants).[45] On the other hand, owners of low- or zero-carbon generating sources (*e.g.*, nuclear, wind, solar, hydro) get the benefit of being paid higher market prices that reflect CO_2 allowance costs, without having to buy allowances. See Figure 7, which shows the breakdown by fuel type of changes in net revenues for power plant owners. As one would expect, carbon-emitting power plant owners generally lose revenue, while owners of nuclear and renewable resources gain during the three years of program implementation.

[45] Note that clearing prices in the three electrical regions we modeled reflect the opportunity cost of CO_2 allowances of the marginal generator in each hour. To the extent that an owner of a relatively high-emitting generating unit purchased an allowance at a higher cost than the opportunity cost of the marginal producer, and has a higher carbon intensity for a given unit of electricity produced, that owner may not fully recover its cost to purchase CO_2 allowances through energy-market revenues.

Figure 7
Net Revenue Change to Power Plant Owners (by Power-Plant Fuel Type and Electrical Region) as a Result of RGGI Implementation During the 2015-2017 Period (NPV, 2018$)

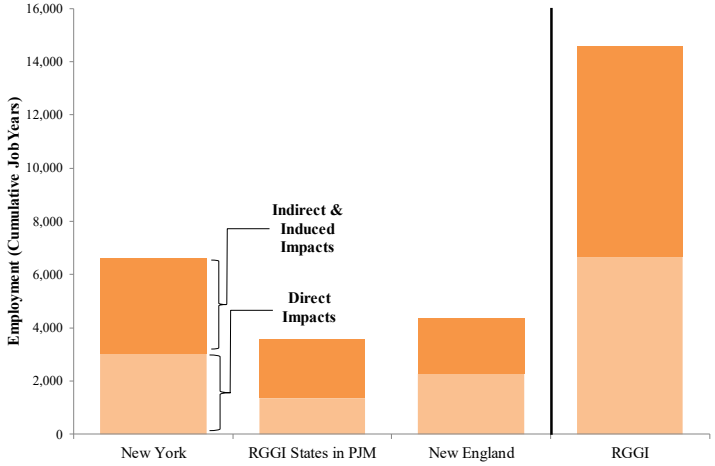


Notes: [1] Figures are reported in 2018 dollars (NPV), converted using a 3-percent discount rate. [2] Figures include PROMOD outputs and capacity market revenue changes calculated separately. [3] Fossil includes natural gas, oil, and coal fired generators. Non-fossil includes nuclear, hydro, pumped storage, wind, solar, and biomass.

Employment and Reduced Payments for Fossil Fuels

In addition to an economic benefit, the use of RGGI proceeds results in a positive employment impact through an increase of over 14,500 new job-years (see Figure 8), and reduced payments to out-of-region providers of fossil fuels by nearly $1.37 billion (NPV) as a result of RGGI's operations during Compliance Period 3.

Figure 8
Net Employment Impact to RGGI States as a Result of RGGI Implementation During the 2015-2017 Period (Cumulative Job Years)



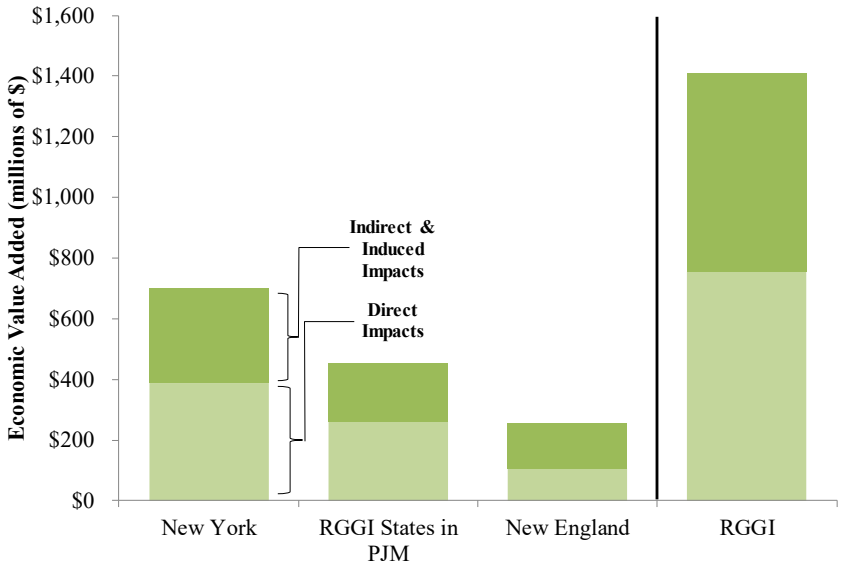
Note: Figures represent employment in terms of cumulative job-years over the study period.

Contributions to Economic Impact

As noted above, RGGI's third compliance period produced a net positive economic benefit of $1.4 billion ($NPV). As previously mentioned, this includes net electric sector impacts to electric consumers and power plant owners, in addition to the non-electric benefits and program spending that result from state spending of RGGI proceeds.[46] As these individual impacts ripple through the economy, they have the net effect of producing positive economic value.

This can be seen in Figure 9, which shows the direct, indirect, and induced economic impacts to the nine-state region from the individual components described above.

Figure 9
Net Economic Impact to RGGI States as a Result of RGGI Implementation During the 2015-2017 Period (NPV, 2018$)



Note: [1] Figures are reported in 2018 dollars (NPV), converted using a 3-percent discount rate. [2] Total economic value added includes the impacts of state spending of RGGI proceeds, including net electric sector impacts to consumers and power plant owners, non-electric benefits, and the economic impact of program spending.

[46] Note that analyzing the economic value added means that a dollar of direct spending does not translate into a direct effect of one dollar of value added. For example, if a dollar is spent in a state on light bulbs, the direct value added is only the net revenue and income of the retail store where the light bulb was purchased, thus excluding the manufacturing costs of the light bulb itself if it was manufactured outside the state. The same holds true for the direct revenue change to power plant owners. Direct electric consumer bill impacts are assumed to be equal to the value added to electric consumers given that any reduction in electric spending equates to a proportional increase in actual value to electric consumers.

5. OBSERVATIONS AND CONCLUSIONS

Based on these results as well as those in our prior assessments of the first two RGGI compliance periods, we have a number of observations that we summarize here. We hope that these provide useful information for the RGGI states as they consider how the program is performing relative to its original goals and for other states and stakeholders who are interested in carbon emission-control policies and programs.

As in its first six years, the RGGI program's third three-year compliance period continued to generate substantial economic benefits for the states while reducing CO_2 emissions.

Economic value added

Our analysis of RGGI impacts over the past three years took into consideration the program's effects on power system dispatch, costs to consumers, revenues to electric generators, and overall performance of the economies in the participating states. Even taking into account decreased revenues to the owners of emitting power plants (and to power-plant owners as a whole), we found positive macroeconomic impacts to the states due to the net benefits to electric consumers and the expenditures of the CO_2 allowance proceeds. RGGI led to approximately $1.4 billion in economic value added (NPV, 2018$) as a result of program implementation in the 2015-2017 period. Thus, the RGGI program continues to generate economic value for its member states.

Jobs

Taking into account the gains and losses to consumers and producers, RGGI Compliance Period 3 led to overall job increases amounting to thousands of new jobs over time. Some of the RGGI job impacts may be permanent, while others may be part-time or temporary. According to our analysis, the net effect is that RGGI activity during the 2015-2017 period leads to over 14,500 new job-years, cumulative over the study period, with each of the nine states experiencing net job-year additions. Jobs that result from RGGI-related expenditures occur in many parts of the economy, with examples including workers who perform efficiency audits and who install energy efficiency measures in residences and commercial buildings, and staff performing training on energy issues.

Fossil-fuel production and imports

Over the past three years, RGGI helped to lower the total number of dollars (by $1.37 billion (NPV, 2018$)) its member states sent outside their region in the form of payments for fossil fuels for power generation and other purposes. Most of the RGGI states' electricity comes from fossil fuels, even though these states produce little coal, natural gas, or oil. Because the RGGI program lowered these nine states' total fossil-fired power production and also reduced their use of natural gas and oil for heating, RGGI reduced the total dollars sent out of state for these energy resources.

Continuation of RGGI program benefits above and beyond the first six years

Our findings on economic impacts of RGGI's third three-year compliance period are consistent with the findings and observations we made with respect to the first and second three-year compliance periods. Those prior assessments revealed net economic benefits to the states participating in the program, including growth in economic output, increased jobs, reinvestment of energy dollars in

local/state economic activity, long-run wholesale electricity cost reductions, and CO_2 emission reductions.

Many factors have changed in the electric industry and the economy since we completed our economic analyses of the RGGI program for Compliance Period 1 (2009-2011) and for Compliance Period 2 (2012-2014). These changes have affected the conditions (*e.g.*, lower gas prices, generation retirements and additions) analyzed in our assessment of Compliance Period 3.

For many reasons (such as the different vintages of each of our studies and notably the year in which we report NPV results), the results of our three studies are not directly additive. Even so, across the three studies, we have found net economic benefits to the RGGI states. Recognizing that these studies have reported outcomes in different-year dollar values, each of our assessments has found positive benefits for the participating RGGI states: $1.6 billion (NPV, 2011$), $1.3 billion (NPV, 2015$), and $1.4 billion (NPV, 2018$) for Compliance Periods 1, 2, and 3 respectively.[47] Our studies have also found that the RGGI-related expenditures led to job creation in each of the three compliance periods of approximately: 16,000 job-years (as of 2011); 14,200 job-years (as of 2015); and 14,500 (as of 2018), respectively.[48]

Thus our modeling of the three compliance periods indicates that, its first decade, RGGI's carbon cap-and-trade program has generated net positive economic value for the participating states' economies on the order of $4 billion dollars.[49] States' participation in RGGI has led to tens of thousands of job-years while also helping to reduce carbon emissions in the RGGI states' electric sector. At the same time, annual carbon-emissions have dropped nearly 50 percent since the program's start in 2009 (for many reasons, including implementation of RGGI).

RGGI's first nine years (2009-2017) provide empirical evidence that carbon-control programs for the power sector can provide positive economic outcomes.

Review of the nation's first multi-state CO_2 emission-control program provides useful information for states that are considering emission-reduction options.

Despite a recent lack of progress at the federal level, many state policymakers continue to focus their attention on the various alternatives for reducing emissions of CO_2 from the electricity sector (and other sectors). A wide range of alternatives are available including cap-and-trade programs, carbon tax/pricing approaches, energy research and development ("R&D") funding, consumer-funded procurements of low- and zero-carbon energy sources, rate policies supporting distributed-energy

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[47] In addition to our prior studies of the RGGI program, RGGI, Inc. and others have conducted studies of the economic impacts of the program. We discuss the differences in these studies later on in this report.

[48] These reflect "job-years," and do not identify what portion of these numbers are associated with permanent versus temporary jobs. Job-years are reported cumulatively over the full study period.

[49] As noted earlier, while the economic results from our three studies are not directly additive, we have used the same foundational analytic methods, assumptions, and data sources across all three studies in order to ensure consistency in study results. While changes in the assumptions used in our earlier studies – *e.g.*, to reflect current market conditions and expectations – could change the results (in either direction), we expect such changes would be small given the consistency in the level of allowance proceeds collected and used by the RGGI states and in the benefits we have found across our studies.

resource development, and funding of energy efficiency measures. The diverse set of policy options used reflects many states' interest in finding cost-effective and workable ways to cut CO_2 emissions. Lessons learned from RGGI's implementation can inform states as they consider their options.

The experience of the RGGI states, including their initial efforts that began in 2003 to work together to develop a multi-state, market-based CO_2 control program, through the nine years of program administration to date, provides a wealth of information. Their experience provides many lessons, most notably that states can collaborate successfully in developing programs to control CO_2 emissions, and market-based CO_2-allowance trading programs – combined with state-driven centralized auctions of CO_2 allowances and with local reinvestment of auction proceeds – can help states meet emission-reduction targets while generating positive economic benefits.

RGGI's positive impacts on state economies are additive to the purpose and expected benefits of the program.

RGGI is not and never was meant to be an economic development program. RGGI's purpose is to reduce CO_2 emissions from power generation in order to help mitigate the economic, social, and environmental risks of climate change. As shown in Figure ES-1, RGGI has contributed to significant reductions in emissions of CO_2 across the RGGI region. In our economic analysis of the RGGI program, however, we do not attempt to quantify the potential long-term benefits of reducing the risks of climate change. The focus of our analysis is specific and narrow: to review the direct impacts of program implementation on the economies of the RGGI states, in order to test the presumption that controlling emissions of CO_2 will somehow lead to negative consequences for states that take action. Our results – which instead reveal positive economic impacts – should be viewed as additive to whatever other benefits flow from reducing climate-change risks.

The RGGI model has successfully achieved CO_2 reductions through a cooperative multi-state framework that preserves state authority.

The states that comprise the RGGI region are highly diverse in many ways: their political settings and policy objectives vary widely across the states and have even changed significantly *within* states over time; their electric-generating portfolios differ substantially in size, technologies, fuel mix, and age; their economic bases vary; and the states have unique legal and regulatory structures that oversee energy, utility, and environmental policies. Despite these differences, however, the RGGI states' experience confirms the possibility that states can work together, particularly when doing so is likely to lower compliance costs and generate economic benefits. The states have designed a multi-state CO_2 program consistent with sound economic principles, completed the stakeholder, legislative, and regulatory steps necessary to adopt and implement the program, and smoothly administered the program and integrated it with wholesale electricity markets. In addition, over just ten years the states have completed two top-to-bottom programmatic reviews and agreed upon major changes to the framework. The RGGI states continue to implement the RGGI platform with an eye towards inclusion and a willingness to collaborate with other states outside the current nine-state region.

Mandatory, market-based carbon-control mechanisms are functioning properly in wholesale electricity markets and have not adversely affected system reliability.

RGGI's nine years of experience supports a conclusion that market-based CO_2 emission-control programs can produce positive economic impacts and meet emission objectives while dovetailing smoothly into the normal operation of power systems. RGGI's implementation has not adversely

affected power system reliability in New England, New York, or PJM. Further, RGGI provides an important example of how states' public policies can be integrated into federally regulated competitive wholesale markets – an issue with which FERC, state regulators, and the courts are actively wrestling.

> The design of the CO_2 market in the RGGI states has allowed for the creative use of public assets in support of diverse state energy/environmental policy and economic outcomes.

The joint decision by the RGGI states to make their CO_2 allowances available to the market through a unified auction has generated substantial revenues for public use. This approach transferred the value of emissions allowances from the public sector to the private sector at a monetary cost. Had the allowances been given away for free, the states would not have had the benefit of the auction proceeds and instead would have transferred away significant public economic value to owners of power plants (which in the RGGI region are merchant generators, not owned by electric distribution utilities). The states' use of allowance proceeds helped them meet a wide variety of social, fiscal, and environmental policy goals, such as assisting low-income customers, achieving advanced energy policy goals, and restoring wetlands, among other things. Notably, however, auctioning of allowances is not necessary for the efficient and effective functioning of the cap-and-trade program design itself. Individual states may still determine their preferred method of moving allowances into the market, which could include auctions, direct allocation, and other mechanisms that may move allowances into the market while transferring or consigning auction value in whole or in part to other entities (such as electric distribution utilities or generating asset owners).

> How allowance proceeds are used affects their economic impacts: Use of auction proceeds to invest in energy efficiency produces the biggest economic bang per buck, in terms of net positive benefits to consumers and to the economy.

The RGGI Memorandum of Understanding ("MOU") fully supports the reality that states place different weights on various goals they hope to accomplish through participation in the program, and that the states will make their own decisions about how to allocate allowances to the market and how to use the proceeds from allowance auctions. But from a strictly economic perspective, some uses of proceeds clearly deliver economic returns more readily and substantially than others. For example, RGGI investment in EE leads to lower electrical demand, lower wholesale power prices, and lower consumer electricity bills. These savings remain in the pockets of electricity users, and the EE investments also produce positive macroeconomic impacts locally as more dollars stay in and contribute to the local economy. We observe that use of the RGGI dollars provides positive multiplier effects in the RGGI states' economies, especially compared to other uses of the auction proceeds.

The RGGI states' experience during 2015-2017 differed along a number of dimensions relative to the first six years of the program.

The RGGI program as implemented during the 2015-2017 period took place in the context of a changing industry and regulatory landscape and with significant changes adopted and implemented by RGGI states. Specifically:

- During 2017, the RGGI states used the six years of prior program experience as they undertook a top-to-bottom review of RGGI, and made a number of changes in the program.
- Many states adjusted how they spent RGGI auction proceeds over time, shifting the use of allowance revenues to reflect changing program and state objectives.
- Fossil fuel prices changed significantly since the start of the program, with natural gas prices (and in turn, wholesale electricity prices) having decreased substantially.
- Electric resources have shifted, with accelerated retirements of older and less efficient (and in most cases, higher-emitting) generating units, and with distributed and central-station renewable energy resources growing at a rapid pace in many of the RGGI states.

Such factors have the potential to influence the administration of RGGI and associated power system and economic impacts. For example, the lower average natural gas prices in 2015-2017 relative to the prior six years led to lower electricity prices in wholesale power markets, which had the effect of reducing the economic value of RGGI-funded EE programs for electricity and heating consumers. Also, the tightening of RGGI's CO_2 emissions cap contributed to an increase in allowance prices, the operating costs of affected generating units, and impacts on wholesale electric prices. The lower number of allowances available to the market, however, was in part offset by higher allowance prices, and thus only slightly reduced auction proceeds available to RGGI states during the 2015-2017 period.

Despite the shifting context for RGGI, the core elements of the program – including a declining CO_2 emissions cap, allowance auctions, reinvestment of auction proceeds, active trading of allowances, monitoring of program administration, participation and outcomes, and cooperation among a diverse set of states and stakeholders – operate in ways that continue to produce positive economic and programmatic results for the participating states.

APPENDIX

MODELING OF ELECTRIC SYSTEM IMPACTS:

PROMOD

Electric System Model Overview: PROMOD

The PROMOD Model

PROMOD is an electric market simulation model marketed by Ventyx. PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load. This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load, and thus calculates Locational Marginal Prices ("LMPs") at individual nodes within the system. PROMOD and similar dispatch modeling programs are used to forecast electricity prices, understand transmission flows and constraints, and predict generation output. Ventyx simulation-ready data includes data on Eastern Interconnection network structure, resources, fuel prices, basis differentials, and demand.

To calculate the impacts of RGGI on power system operations and outcomes, we used PROMOD to simulate the "with RGGI" and "without RGGI" systems that serve the nine RGGI states,[1] with the difference between the two simulations being the direct incremental impacts of RGGI on the power system. These two simulation runs otherwise maintained the same inputs, in terms of fuel prices, power plants available to be dispatched, power plant operational characteristics, NO_x and SO_2 allowance costs, baseline load levels, and so forth. The "with RGGI" case was benchmarked to actual power system operations in the historical months of the 2015-2017 time period (in New England, New York, PJM). With this as a starting point, several core assumptions (*e.g.*, load levels that change as a result of energy efficiency investments, removal of renewable resources resulting from RGGI investments, removal of the cost of RGGI CO_2 allowances) were changed, and the model re-run to simulate the "without RGGI" case. As described further below, the simulation period is the historical 2015-2017 period, along with a 10-year tail period (through July of 2027) to capture the implications of energy efficiency programs implemented through use of RGGI allowance proceeds generated to date. PROMOD outputs include changes in power plant operations (*e.g.*, revenues, costs), emissions, and prices.

Fuel Prices in the Power Sector

Natural Gas

Natural gas prices are calculated as a Henry Hub base price plus a regional Hub basis differential. From January 2015 through March 2017, the Henry Hub price is based on Ventyx/PROMOD data. From April 2017 through January 2018, the Henry Hub price is a monthly average of historical daily NYMEX spot prices. From February 2018 through

[1] As described below, we simulated these systems (PJM, NYISO, ISO-NE) using a database that also includes Canada's system (which is interconnected to NY and ISO-NE) and Midwest ISO (which is interconnected to PJM).

March 2019, the Henry Hub price is based on NYMEX futures prices. From April 2019 through December 2027, the base Henry Hub NYMEX price is grown at the rate of change in the Energy Information Administration's (EIA's) Annual Energy Outlook (AEO) Henry Hub spot price.[2] To capture the delivered price of natural gas into the region of interest, we use the regional basis price differentials from PROMOD throughout the whole study period. These basis differentials may change based on assumed infrastructure improvements over time.

Other Fuels

Distillate oil and Residual oil prices are based on Ventyx fuel price forecasts. Coal prices are based on Ventyx unit-level fuel price forecasts.

Power Plants: Existing Units, Unit Retirements and Additions

The set of power plants is based on actual plants operating within eastern PJM, NYISO, ISO-NE, Ontario, and MISO. We made changes to this dataset (identical in the "with RGGI" and "without RGGI" runs) to reflect unit retirements and power plant additions (*e.g.*, to meet the states' renewable portfolio standards (RPS)). Unit retirement decisions are based on assumed retirements in the PROMOD generator dataset, which rely on information from Ventyx as of April 2017. Some of these retirements have been adjusted as the result of a review of planning documents published by PJM, NYISO, and ISO-NE, along with press releases. Unit additions listed in PROMOD's generator dataset have not been adjusted.

Renewables

RPS MWh targets by state are sourced from Lawrence Berkeley National Labs (LBNL) for PJM and NYISO and from the updated ISO-NE RPS Workbook for ISO-NE. In NYISO and ISO-NE, beginning in 2018, we add renewable capacity sufficient to meet 50 percent of the renewable target in each region and assume that the other 50 percent of each state's RPS target is met through alternative compliance payments rather than new renewable energy. In PJM, this assumption would result in growth far above the historic levels observed. Thus, in PJM we assume that growth in RPS eligible resources continues at the recent historic rate of development and that any target not met with RPS eligible generation is met with an alternative compliance payment. In NYISO and ISO-NE, the composition of incremental renewable capacity is based on the proportional distribution of renewable technology types in the current interconnection queues of each region while in PJM the composition of incremental renewable capacity is based on the proportion of additions in recent years. To determine the incremental capacity required to meet this energy demand, average historical

[2] In all cases where NYMEX data is grown at an AEO growth rate, the method is as follows:

- The growth rate used is the rate of change between two specific AEO annual data points, rather than the overall AEO growth rate for a particular fuel.
- The growth rate is applied to the data point for the same month in the prior year, rather than the immediately preceding month.

capacity factors by technology type and by region were obtained from the SNL Financial power plant database.

Generic Capacity Additions to Meet Resource Adequacy

After the incremental addition of renewable capacity and retirement of units as discussed above, we analyzed the extent to which each region's capacity satisfied forecasted resource adequacy requirements in each year, based on each region's capacity planning process. This review determined that additional resources were required in NYISO during each scenario, so new capacity was added based on generic natural gas combined cycle and gas turbine plants. The operating characteristics of these new plants are assumed to be the same as recently built natural gas generating units. The units were placed on the high-voltage transmission network in each region to maximize deliverability. Combined cycle and gas turbine plants were both added to the system.

Emissions costs

RGGI-Related CO_2 Allowance Prices

Prices for CO_2 allowances were modeled for each month in Compliance Period 3 using the most-recent quarter's actual CO_2 allowance price as revealed by auction clearing prices for auctions 27 through 38. No CO_2 price was assumed after December 2017, in light of the assumption that all needed CO_2 allowances had been purchased as of the 38th auction to cover CO_2 emissions during the second three-year compliance period.

NO_x and SO_2 Allowance Prices

NO_x and SO_2 allowance prices are based on Ventyx price forecasts.

Load Forecasts

RTO-level load forecasts are provided by Ventyx, and based on RTO planning documents. ISO-NE data is based on adjusted (*e.g.*, for EE, PDR, and PV) load from the 2017 CELT Report. NYISO data is based on adjusted load from the 2017 Gold Book. PJM data is based on adjusted load from the 2017 PJM Load Forecast Report.

Load Profiles

To account for the impact of energy efficiency savings on hourly load in the "without RGGI" case (*i.e.*, when load is increased to account for the removal of RGGI-funded EE programs), data on energy efficiency spending from each RGGI state were aggregated by program type. Total energy savings from each program type were divided proportionally to load, based on a typical hourly profile of energy savings resulting from each program type. From here, hourly state savings for each year were determined and modeled in each RGGI zone. Similarly, state spending on renewables was assumed to be for distributed solar PV, and converted to state load savings using LBNL average solar costs and SNL capacity factors. Total state load

savings were proportionally assigned to constituent service areas based on native load in each area.

General Adjustments

Outages

Random generator outages are calculated once using PROMOD's algorithm, and fixed between the "with RGGI" and "without RGGI" cases.

Generator Maintenance

Scheduled generator maintenance is fixed between the "with RGGI" and "without RGGI" cases to fulfill unit maintenance requirements.

MODELING OF MACROECONOMIC IMPACTS:

IMPLAN

Macroeconomic Model Overview: IMPLAN

Our analysis of macroeconomic impacts of RGGI uses the "IMPLAN" model. IMPLAN (which stands for "IMpact analysis for PLANning") is a social accounting/input-output ("I/O") model that attempts to replicate the structure and functioning of a specific economy.[3] IMPLAN is widely used for economic impact assessments in the public and private sectors.

Input/output models are based on long-standing, well-established and broadly accepted methodologies designed to estimate the impacts on a regional economy of a change in economic activity. Such models are based on a methodology established decades ago by economists for tracking the effects on changes in the inputs or outputs of an industry (or some other segments of an economy) as they ripple through the economy.

The broad conventional approach to examining these economic flows is to rely on national economic input-output account survey data. These data are based on census information collected from businesses that track the flows of dollars into and out of enterprises. The data make up the basis for the input/output tables that reflect the movement of dollars within an economy and the multiplier effects that reflect the role of dollars in influencing different multiplier effects in different segments of economies. The Bureau of Economic Analysis within the U.S. Department of Commerce collects information related to these relationships among different segments of regional economies. Over the years, these economic accounts are verified and serve as the basis for a wide variety of macroeconomic metrics (such as Gross Domestic Product, Gross State Product, and countless other economic variables). The IMPLAN databases used for the RGGI region (and the nine RGGI states individually) are rooted in these national economic account information sources.

The IMPLAN model allows one to investigate various interactions in a defined economy (in this case, the RGGI region and the individual states within it), and to calculate various economic impacts in that economy when a new activity affects money flows around the economy (such as investments in energy efficiency, assistance in helping customers pay their energy bills, lost revenues for owners of power plants, etc.).

IMPLAN relies on a detailed system of accounting for relationships among different parts of the economy, and relies on national economic data for the specified region. The model tracks dollars spent in a region, including dollars that circulate within it (*e.g.*, transfers of dollars from consumers to producers), dollars that flow into it (purchases of goods and services from outside the local economy), and dollars that flow outside of it (*e.g.*, payments to the federal government). The model thus examines inflows, outflows, and interactions within the economy under study.

Specifically, the model captures various effects, including:

[3] Information provided on IMPLAN's website, available at http://www.implan.com/. IMPLAN (now known as IMPLAN Pro) is a proprietary tool with accompanying data files for different regions which provides the ability to create complete, extremely detailed Social Accounting Matrices and Multiplier Models of local economies.

- *Employment effects* (the total number of job-years created or lost);
- *Income effects* (the total change in income to employees that results from the economic activity); and
- *"Value-added" effects* (the total economic value added to the economy, which reflects the gross economic output of the area less the cost of the inputs).

In our analysis, we focused on added value, since this is the overall measure of change in macroeconomic activity.

There are various ways in which the new activity creates impacts, each of which is separately tracked by the model:

- *Direct effects:* the initial set of inputs that are being introduced into the economy. In our study, this included the direct effects of RGGI on owners of power plants ("producers") as a whole, on energy "consumers" (consumers of electricity, natural gas and heating oil), and use of RGGI proceeds to buy goods and services in the economy (*e.g.*, investment in energy efficiency, work training programs, bill-payment assistance for low income consumers, etc.).
- *Indirect effects:* the new demand for local goods, services and jobs as a result of the new activity, such as the purchase of labor to retrofit buildings with energy efficient measures, or to train workers in these skills. Some RGGI auction proceeds may lead to payments for things outside the local region (*e.g.*, the purchase of efficient lighting equipment or solar panels manufactured outside of the RGGI region), and thus represents a way that such funds do not stay within the local economy after having been generated by power plant owners' purchases of CO_2 allowances.
- *Induced effects:* the increased spending of workers resulting from income earned from direct and indirect economic activity.

Direct effects are determined by an "Event" as defined by the user (*i.e.*, a $10 million dollar purchase of worker training is a $10 million dollar direct effect; a $10 million dollar contribution to clean energy R&D is a different $10 million dollar direct event).[4] The indirect effects are determined by the amount of the direct effect spent within the study region on supplies, services, labor and taxes. Finally, the induced effect measures the money that is re-spent in the study area as a result of spending from the indirect effect. Each of these steps recognizes an important leakage from the economic study region spent on purchases outside of the defined area. Eventually these leakages will stop the cycle.

[4] Note that analyzing the economic value added means that a dollar of direct spending does not translate into a direct effect of one dollar of value added. For example, if a dollar is spent in region on light bulbs, the direct value added is only the net revenue and income of the retail store where the light bulb was purchased, thus excluding the manufacturing costs of the light bulb itself.

More specifically, the effects are:

- *Direct effects* - The set of expenditures applied to the predictive model (*i.e.*, I/O multipliers) for impact analysis. It is a series of (or single) production changes or expenditures made by producers/consumers as a result of an activity or policy. These initial changes are determined to be a result of this activity or policy. Applying these initial changes to the multipliers in an IMPLAN model will then display how the region will respond, economically, to these initial changes.
- *Indirect effects* - The impact of local industries buying goods and services from other local industries. The cycle of spending works its way backward through the supply chain until all money leaks from the local economy, either through imports or by payments to value added.
- *Induced effects* - The response by an economy to an initial change (direct effect) that occurs through re-spending of income received by a component of value added. IMPLAN's default multiplier recognizes that labor income (employee compensation and proprietor income components of value added) is not a leakage out of the regional economy. This money is recirculated through the household spending patterns causing further local economic activity.

State Economic Database

Our IMPLAN analysis of the RGGI states was based on the most recent state data files (2016) for each of the nine states, as available from IMPLAN. These state-level data files include information for a set of highly disaggregated industries, sorted generally by their 4 and 5 digit NAICS codes.[5]

IMPLAN data files are compiled from a wide variety of sources including the U.S. Bureau of Economic Analysis, the U.S. Bureau of Labor, and the U.S. Census.[6] They include information about regional employment, income, value-added, household and government consumption. Examples include: employee compensation; proprietary income; federal, state and local taxes affecting income, sales, real estate, and so forth; personal consumption expenditures at nine income levels; federal government purchases (military and non-military) and investments; purchases by local and state governments (including educational institutions); inventory purchases; capital formation; foreign exports; and inter-institutional transfers. They also include unique national input-output structural matrices and unique annual trade flow models.

[5] NAICS codes are tied to the North American Industry Classification System, which is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy.

[6] The IMPLAN data files use federal government data sources including the following federal programs: Bureau of Economic Analysis Benchmark I/O Accounts of the US and Output Estimates; Bureau of Labor Statistics Covered Employment and Wages (ES202) Program and Consumer Expenditure Survey; Census Bureau County Business Patterns, Decennial Census and Population Surveys, Censuses and Surveys; Department of Agriculture Crop and Livestock Statistics; and US Geological Survey.

Expenditure Categories Used in IMPLAN Modeling

In our IMPLAN analysis, we assigned RGGI expenditures into a variety of IMPLAN sector categories, based on assumptions about the character of the economic activity tied to each particular category of RGGI programs.

For example, expenditures on energy efficiency were modeled mainly as either residential (construction of new single- or multi-family structures, or maintenance and repair of residential structures) or commercial/industrial (construction of new commercial structures or maintenance and repair of non-residential structures). Other non-energy efficiency examples include RGGI-related expenditures on: education and outreach programs (modeled as other educational services); electric consumer bill changes and direct bill assistance (modeled based on IMPLAN defined demand for electricity in a particular state); revenue changes to power plant owners (modeled as electric power generation); administration (modeled as other administrative services); and renewable generation development (modeled as construction of new power and communication structures).

DISCOUNT RATE

Discount Rate Overview

Our analysis involves the assessment of costs (*e.g.*, expenditures and investments, decreases in revenues) and benefits (*e.g.*, lower electricity bills for consumers, added value in the economy) that occur in different periods of time. We examine the flow of dollars associated with the purchase of CO_2 emissions allowances in the RGGI auctions that took place in 2015 through 2017, the impact of these allowances in electricity prices during this time period, and the impact of RGGI-funded programs on electric system outcomes and the macro-economy from 2015-2027. Thus the study period, in one way or another, spans from 2015 to 2027.

To compare these benefits and costs properly, we discount all dollar flows into net present values as of 2018. We calculate the net present value by applying an appropriate discount rate to dollar flows in different years, and then subtracting the sum total of discounted costs from the sum total of discounted benefits.

The discount rate is the tool that accounts for the time value of money – the concept that a dollar today is typically worth more than the same amount of money in the future because of the opportunity cost of money. A dollar today could be put into an investment or an interest-bearing activity that will typically cause it to grow in value, so that dollar today is worth more to its holder than a dollar received in the future. Further, inflation diminishes the purchasing power of dollars over time. And uncertainty about future economic outcomes, combined with a preference for nearer-term gratification, typically causes a dollar in hand today to be worth more than one tomorrow. The higher the discount rate, the lower is the present value of future cash flows.

Our analysis required choosing an appropriate discount rate. Our analysis reflects dollars in the hands of producers, who are largely private enterprises, and consumers, made up of households, businesses, government energy users, and others. RGGI-funded activities add value to the macro-economy of a wide range of actors in the nine RGGI states in the Northeastern and Mid-Atlantic region. The choice of an appropriate discount rate needs to properly reflect the opportunity costs of these various private and public entities in society.

There is a deep literature on the proper discount rate to use in analyzing certain public policies or activities involving society rather than particular producers or consumers.

- **A private discount rate** is used when analyzing the investment options of private enterprises. The appropriate private discount rate varies, depending upon whether the economic analysis focuses on a single company (where that company's weighted average cost of capital would be appropriate) versus a group of companies (where the appropriate discount rate would reflect their collective opportunity costs).

- **A different discount rate** may be appropriate for use by government agencies when they analyze investments, when consumers look at their economic options, or when evaluating the rate at which society as a whole is willing to trade off present for future benefits.

- **Government discount rate**: For example, in 1992, the federal government's Office of Management and Budget issued OMB Circular No. A-94, "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs." This document established guidance for discount rates used in benefit-cost and other types of economic analysis by federal agencies, with updates on certain discount rates to use when the interest rate and inflation assumptions in the budget are changed. Because "public investments and regulations displace both private investment and consumption," OMB's recommended discount rate for public investments was a real discount rate of 7 percent, which "approximates the marginal pretax rate of return on an average investment in the private sector in recent years."[7] Various analyses that involve "internal government investments" with effects on increased government revenues or decreased government costs (like "an investment in an energy-efficient building system that reduces Federal operating costs") should use a discount rate reflecting a Treasury bond with a comparable maturity to the investment. But where a government activity provides "a mix of both Federal cost savings and external social benefits," where possible the "Federal cost savings and their associated investment costs may be discounted at the Treasury rate, while the external social benefits and their associated investment costs should be discounted at the 7 percent real rate." At the time the circular was written in 1992, a 10-year Treasury was 7 percent nominal and 3.6 percent real. Over the last decade, these Treasury rates on average were 2.9 percent nominal and 1.0 percent real.[8]

- **Consumption discount rate:** Real-world conditions create differences between opportunity costs of consumers relative to private actors and governments: "Among other things, private sector returns are taxed (often at multiple levels), capital markets are not perfect, and capital investments often involve risks reflected in market interest rates. These factors drive a wedge between the *social rate* at which consumption can be traded through time (the pre-tax rate of return to private investments) and the rate at which *individuals* can trade consumption over time (the post-tax consumption rate of interest). …[For example:] …Suppose the market rate of interest, net of inflation, is 5%, and that taxes on capital income amount to 40 percent of the net return. In this case, private investments will yield 5%, of which 2% is paid in taxes to the government, with individuals receiving the remaining 3%. From a social perspective, consumption can be traded from the present to the future at a rate of 5%. But individuals effectively trade consumption through time at a rate of 3% because they owe taxes on investment earnings. As a result, the

[7] OMB Circular No. A-94 (1992), "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs." See http://www.whitehouse.gov/omb/circulars_a094/.

[8] OMB Budget Assumptions – Nominal and Real Treasury Interest Rates for Different Maturities (from the annual budget assumptions for the first year of the budget forecast), November 27, 2017. See https://www.whitehouse.gov/wp-content/uploads/2017/11/DISCHIST-2018-1.pdf.

consumption rate of interest is 3%, which is substantially less than the 5% social rate of return on private sector investments (also known as the social opportunity cost of private capital)."[9]

- **Social discount rate**: "Social discounting… is discounting from the broad society-as-a-whole point of view that is embodied in benefit-cost analysis (BCA). *Private discounting*, on the other hand, is discounting from the specific, limited perspective of private individuals or firms. Implementing this distinction can be complex… using a given private discount rate instead of a social discount rate can bias results as part of a BCA."[10]

Recent guidance provided by the U.S. Environmental Protection Agency makes the following recommendations for discount rates to use in analyzing programs that involve flows to various entities in society over different periods of time, especially when "there is a significant difference in the timing of costs and benefits, such as with policies that require large initial outlays or that have long delays before benefits are realized."[11]

> "Calculate the NPV using the consumption rate of interest. This is appropriate for situations where all costs and benefits occur as changes in consumption flows rather than changes in capital stocks, *i.e.*, capital displacement effects are negligible. As of the date of this publication, current estimates of the consumption rate of interest, based on recent returns to Government-backed securities, are close to 3%. Also calculate the NPV using the rate of return to private capital. This is appropriate for situations where all costs and benefits occur as changes in capital stocks rather than consumption flows. The Office of Management and Budget estimates a rate of 7% for the opportunity cost of private capital."[12]

For these various reasons, we used a 3 percent ("public" or "social") discount rate in our analysis.

[9] US Environmental Protection Agency (National Center for Environmental Economics, Office of Policy), "Guidelines for Preparing Economic Analyses," EPA 240-R-10-001, December 17, 2010 (updated May 2014)" ("EPA Guidelines"), page 6-6.

[10] EPA Guidelines, page 6-1.

[11] EPA Guidelines, page 6-4.

[12] EPA Guidelines, page 6-19.

Attachment 41

State Air Pollution Control Board

Report to the Board

Travis A. Voyles
Acting Secretary of Natural and Historic Resources
August 31, 2022

RGGI is a Bad Deal for Virginia

RGGI Is Not Working—Whether you agree with the principals of a cap and trade regime, the way RGGI is set up for VA does not work.

Burden—Costs passed on to the consumer without any change in behavior by the electricity providers due to VA's regulatory structure.

Abandoned Responsibility—Forfeited our important decision-making rights to Northeastern states who have more say over our energy policy than any VA consumer.

Funding—Virginians don't need a regressive energy tax through RGGI to fund important programs. These are not the goals that RGGI was meant to achieve.

***Action*—Complete repeal by end of 2023, ending VA's participation in RGGI.**

Current Regulatory Framework

Virginia Clean Economy Act

- requires shift in generation mix to 100% renewable by 2050

Clean Energy and Community Flood Preparedness Act

- established mechanisms to join RGGI
- specified DCR/DHCD programs to receive funding

Regional Greenhouse Gas Initiative (RGGI)

Youngkin Administration

January 2022 Governor's Executive Order 9 – *Protecting Ratepayers from the Rising Cost of Living due to the Regional Greenhouse Gas Initiative*

- Directive to re-evaluate cost/benefits, repeal the trading rule, and remove VA from RGGI

March 2022 DEQ Report – *VA Carbon Trading Rule and RGGI Participation: Costs and Benefits*

March 2022 DEQ Report

Key Takeaways:

- RGGI operates as a direct tax because all fees paid are passed through to the ratepayers per Virginia Legislation.
- By design, utilities are not penalized for failure to meet RGGI CO_2 emissions since they can pass on the costs to the ratepayers, and consumers are unable to avoid these costs since they do not have the opportunity to switch electric providers.
- Other states designed their systems to provide rebates to their ratepayers, and while Virginia consumers were originally told the program would return the proceeds to the ratepayers, instead the General Assembly chose to disburse the funds through grant programs.
- The costs of compliance with the trading rule and participation in RGGI are materializing in higher electricity rates for all ratepayers, and future rate increases due to RGGI are expected and will be tied to the allowance prices which are difficult to predict.

The Path Forward—*Process*

Regulatory Action

- Repeal the trading rule and end VA's participation in RGGI
- Full Administrative Process Act (APA) process
- Notice of Intended Regulatory Action (NOIRA)

Timing—Complete repeal by the end of 2023

- 3-year compliance/control period of RGGI
- Contractual agreement with RGGI Inc.

Provides For Stable Withdrawal for Regulatory Certainty

- Smooth and orderly exit
- Avoid market disruptions

The Path Forward—*Rationale*

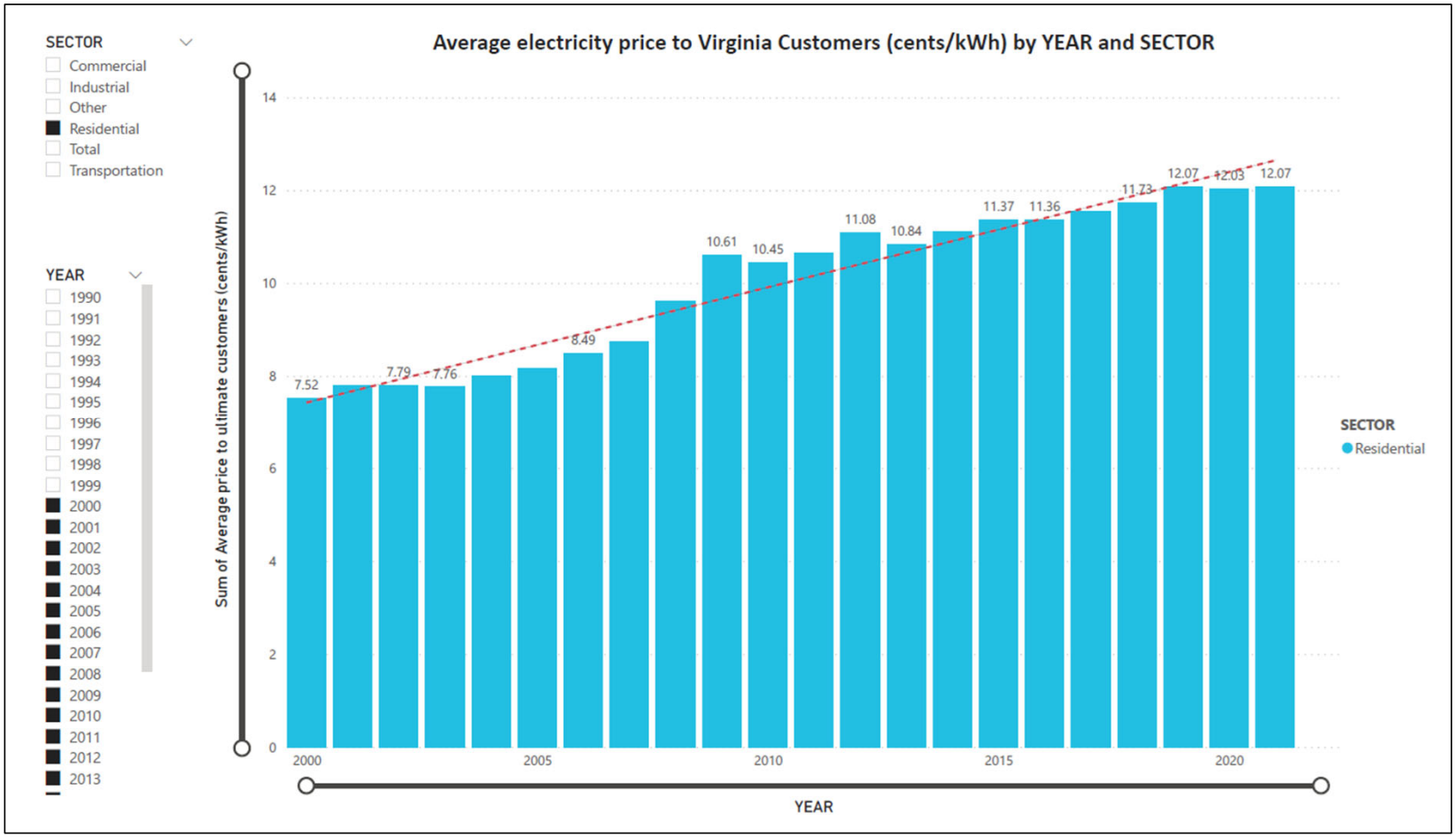
- Increasing Energy Costs
- Virginia's Energy Independence
  - No Control of RGGI Costs
- RGGI Effectiveness and Burden
  - Direct Consumer Tax
  - Duplicative Transition Cost of RGGI
  - Emissions Reductions without RGGI

Increasing Energy Costs

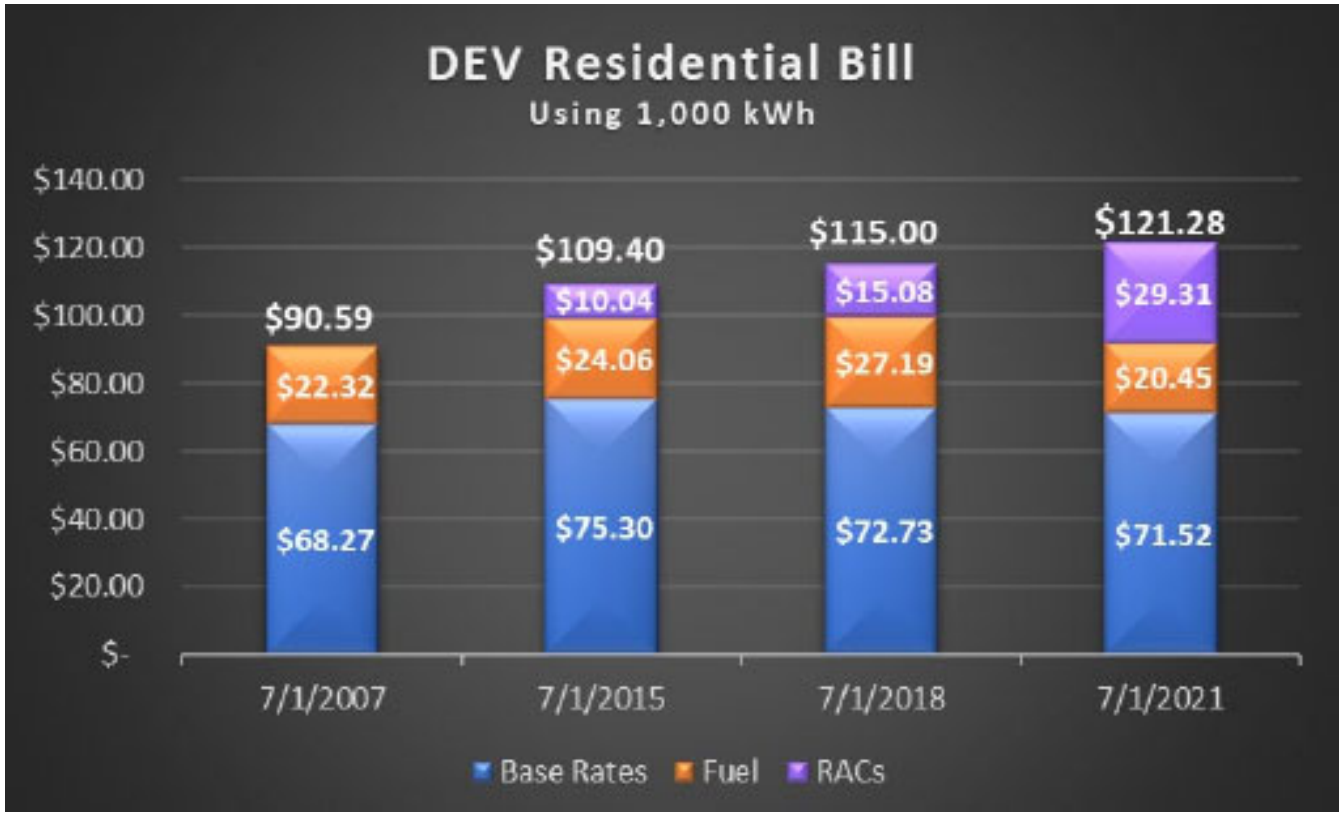
- Over the past 15 years, an average monthly residential bill for a Dominion customer has increased by over $30 – roughly 34%
  - $90.59 (2007) → $121.28 (late 2021)

- Consumer energy prices up 41.6% in the last year
  - June 2022 alone +9%
  - Natural gas price index is sharply higher (+38%)
    - NG is the predominant fuel in VA
  - Resulting in rate adjustments amounting to +18%

Increasing Energy Costs



Increasing Energy Costs

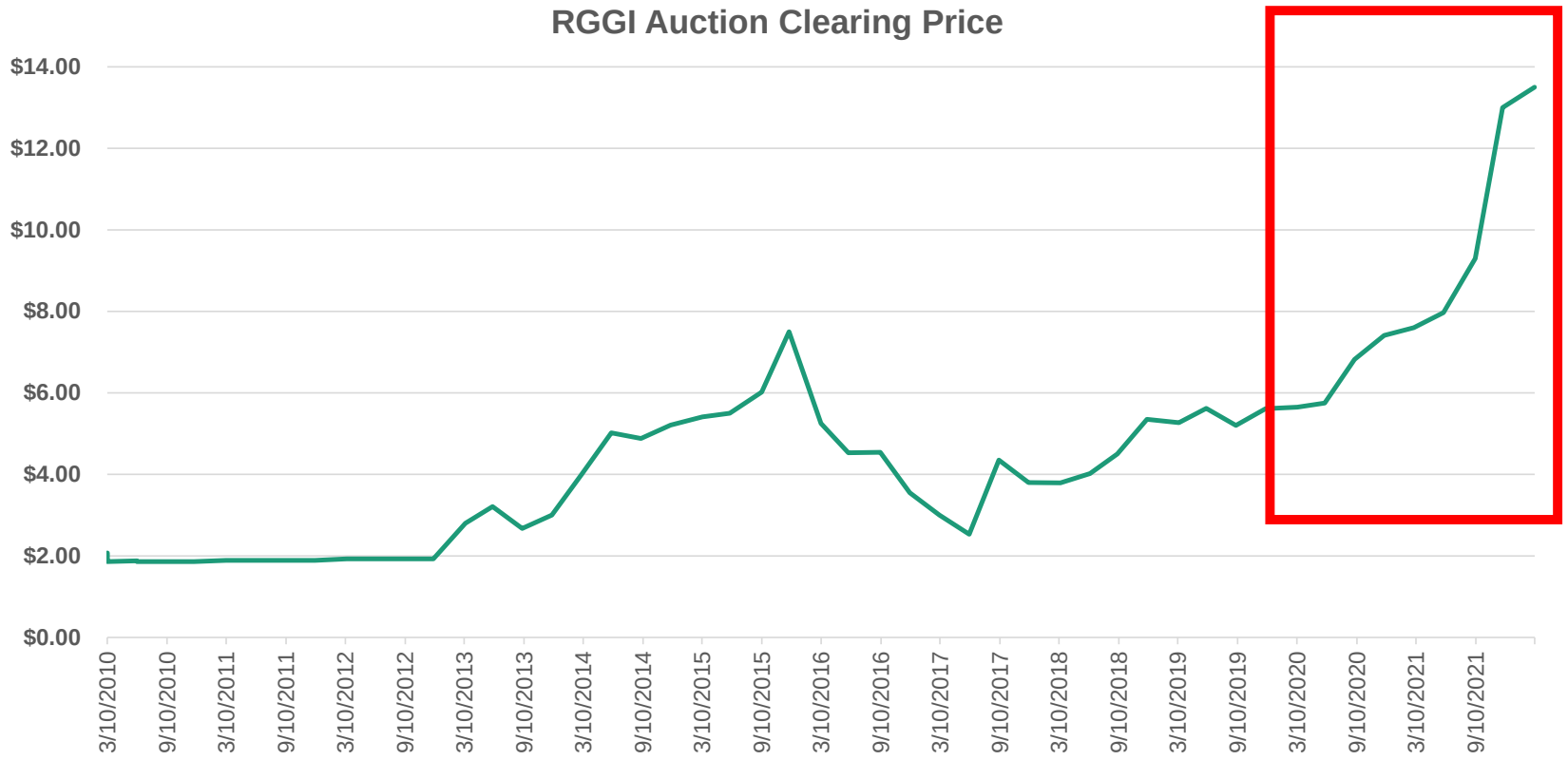


Increasing Energy Costs

DEV Electric Utility Residential Bills
As of July 1, 2021

Recovery Mechanism	Description	Current Residential Bill	Proposed Increase if Pending	Proposed Bill	Requested Eff. Date
Base Rates	Base	$ 71.52	$ (0.30)	$ 71.22	1/1/2022
Fuel Factor	Fuel	$ 20.45		$ 20.45	-
Rider T1	Transmission	$ 10.59	$ (3.69)	$ 6.90	9/1/21
Rider B	Biomass	$ 0.45	$ (0.15)	$ 0.30	4/1/22
Rider BW	Brunswick Gas CC	$ 1.95	$ 0.15	$ 2.10	9/1/21
Riders C1A/C2A/etc.	Energy Efficiency	$ 1.47	$ (0.10)	$ 1.37	9/1/21
Rider CCR	Coal Ash	$ -	$ 2.94	$ 2.94	12/1/21
Rider CE	Solar	$ 0.19	$ -	$ 0.19	-
Rider E	Environmental	$ 1.67	$ (0.42)	$ 1.25	11/1/21
Rider GV	Greensville Gas CC	$ 2.85	$ (0.10)	$ 2.75	4/1/22
Rider R	Bear Garden Gas CC	$ 1.07	$ 0.07	$ 1.14	4/1/22
Rider RBB	Rural Broadband	$ -	$ 0.03	$ 0.03	8/1/21
Rider RGGI	RGGI	$ -	$ 2.39	$ 2.39	8/1/21
Rider RPS	RECs	$ -	$ 0.18	$ 0.18	8/1/21
Rider S	VCHEC	$ 3.61	$ 0.09	$ 3.70	4/1/22
Rider U	Strategic Undergrounding	$ 2.14	$ 0.39	$ 2.53	4/1/22
Rider US-2	Solar	$ 0.19	$ (0.01)	$ 0.18	9/1/21
Rider US-3	Solar	$ 0.71	$ -	$ 0.71	-
Rider US-4	Solar	$ 0.19	$ -	$ 0.19	-
Rider W	Warren Gas CC	$ 2.23	$ 0.11	$ 2.34	4/1/22
Total		**$ 121.28**	**$ 1.58**	**$ 122.86**	

Energy Independence—*No Control of RGGI Costs*



RGGI Burden & Effectiveness – *Direct Consumer Tax*

- Unlike other RGGI states, VA's electric utilities are noncompetitive monopolies.
- VA regulated rate structure provides no incentive for utilities to reduce emissions or compliance costs.

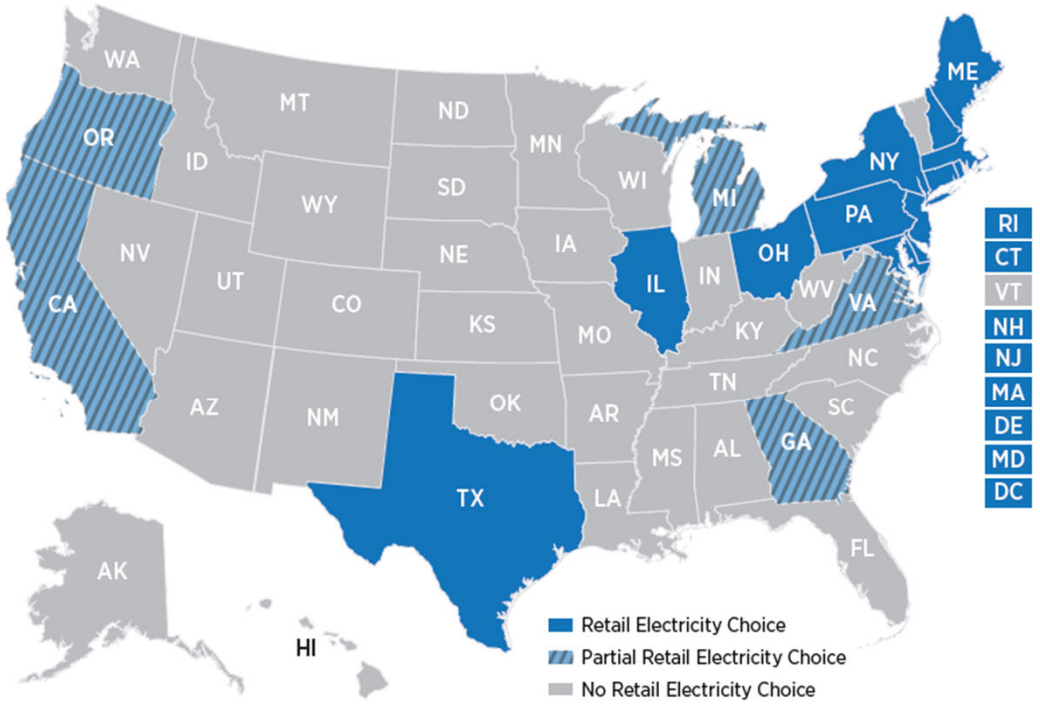


Figure 1. States with retail electricity choice

Source: State public utility commissions (2017)*

RGGI Burden & Effectiveness – *Duplicative Transition & Direct Tax*

DEV Electric Utility Residential Bills
As of July 1, 2021

Recovery Mechanism	Description	Current Residential Bill	Proposed Increase if Pending	Proposed Bill	Requested Eff. Date
Base Rates	Base	$ 71.52	$ (0.30)	$ 71.22	1/1/2022
Fuel Factor	Fuel	$ 20.45		$ 20.45	-
Rider T1	Transmission	$ 10.59	$ (3.69)	$ 6.90	9/1/21
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Rider R	Bear Garden Gas CC	$ 1.07	$ 0.07	$ 1.14	4/1/22
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Rider RGGI	RGGI	$ -	$ 2.39	$ 2.39	8/1/21
Rider RPS	RECs	$ -	$ 0.18	$ 0.18	8/1/21
Rider S	VCHEC	$ 3.61	$ 0.09	$ 3.70	4/1/22
Rider U	Strategic Undergrounding	$ 2.14	$ 0.39	$ 2.53	4/1/22
Rider US-2	Solar	$ 0.19	$ (0.01)	$ 0.18	9/1/21
Rider US-3	Solar	$ 0.71	$ -	$ 0.71	-
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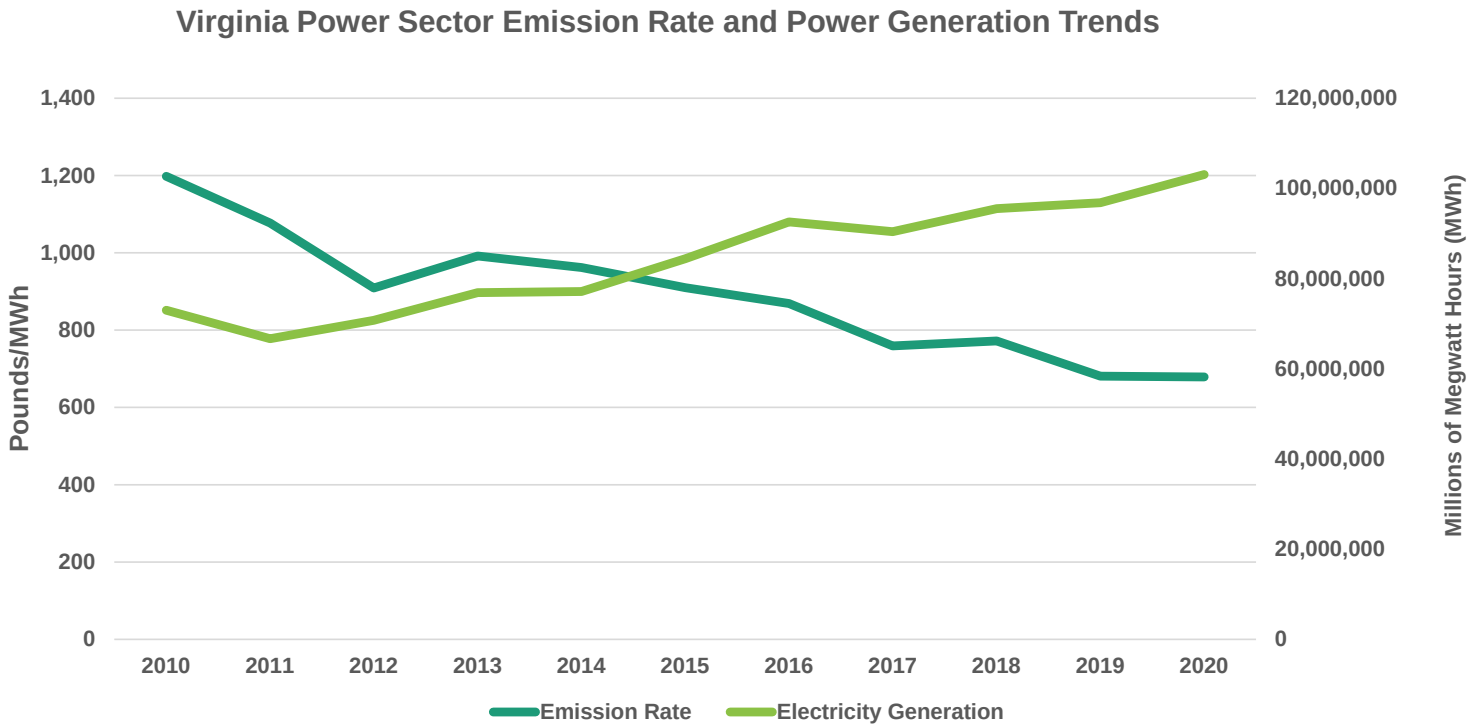
Rider W	Warren Gas CC	$ 2.23	$ 0.11	$ 2.34	4/1/22
Total		**$ 121.28**	**$ 1.58**	**$ 122.86**	

RGGI Burden & Effectiveness – *Emissions Reduction Without RGGI*

- Power sector is already getting cleaner for many other reasons
- Power sector average CO_2 emission rate with a 43% reduction from 2010 to 2020
- Emission rate decrease while in-state electricity generation has increased by 41% from 2010 to 2020



RGGI is a Bad Deal for Virginia

RGGI Is Not Working—Whether you agree with the principals of a cap and trade regime, the way RGGI is set up for VA does not work.

Burden—Costs passed on to the consumer without any change in behavior by the electricity providers due to VA's regulatory structure.

Abandoned Responsibility—Forfeited our important decision-making rights to Northeastern states who have more say over our energy policy than any VA consumer.

Funding—Virginians don't need a regressive energy tax through RGGI to fund important programs. These are not the goals that RGGI was meant to achieve.

***Action*—Complete repeal by end of 2023, ending VA's participation in RGGI.**

Attachment 42

An official website of the United States government Here's how you know

EPA

Menu

CAMPD Clean Air Markets Program Data
A program of the U.S. EPA

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Data Preview
(Viewing the first 3 records of 3)

Bookmark

State	Year	Gross Load (MWh)	Steam Load (1000 lb)	SO2 Mass (short tons)	CO2 Mass (short tons)
VA	2020	65,931,048.77	25,363,195.49	1,525.061	32,756,022.322
VA	2021	55,180,481.6	28,656,693.55	1,320.841	28,623,529.826
VA	2022	51,288,748.01	31,633,767.86	1,320.212	27,251,719.101

Attachment 43

An official website of the United States government Here's how you know

EPA

Menu

CAMPD Clean Air Markets Program Data
A program of the U.S. EPA

Bookmark

Custom Data Download

Preview Data

Data Type | Filters (2)

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Data Preview
(Viewing the first 18 records of 18)

Bookmark

State	Year	Gross Load (MWh)	Steam Load (1000 lb)	SO2 Mass (short tons)	CO2 Mass (short tons)
VA	2005	43,887,590.35	39,335,607.06	207,748.036	38,423,850.155
VA	2006	38,716,826.33	36,589,485.17	171,942.849	34,221,022.367
VA	2007	44,826,997.76	39,662,919.73	172,685.215	37,999,633.229
VA	2008	39,260,466.52	54,541,116.05	125,985.155	34,217,740.052
VA	2009	37,626,173.84	36,199,211.65	95,414.715	30,348,018.33
VA	2010	41,884,828.79	47,450,449.09	93,388.573	35,702,895.538
VA	2011	38,201,014.8	36,172,523.44	68,070.753	29,137,017.766
VA	2012	38,337,943.24	35,008,976.55	31,487.625	25,682,697.832

Bookmark

State	Year	Gross Load (MWh)	Steam Load (1000 lb)	SO2 Mass (short tons)	CO2 Mass (short tons)
VA	2012	38,337,943.24	35,008,976.55	31,487.625	25,682,697.832
VA	2013	40,539,143.84	55,436,883.63	38,778.159	32,053,976.154
VA	2014	39,145,245.56	58,481,354.84	33,087.612	32,086,789.807
VA	2015	48,723,421.16	49,061,033.83	15,618.333	33,575,564.552
VA	2016	55,115,536.82	49,481,626.83	10,315.893	36,176,792.474
VA	2017	52,718,115.27	47,518,905.34	5,790.729	32,376,190.346
VA	2018	57,217,428.96	45,409,589.92	8,875.318	34,399,464.849
VA	2019	60,573,674.52	30,747,889.53	2,342.786	31,030,890.35

Bookmark

State	Year	Gross Load (MWh)	Steam Load (1000 lb)	SO2 Mass (short tons)	CO2 Mass (short tons)
VA	2015	48,723,421.16	49,061,033.83	15,618.333	33,575,564.552
VA	2016	55,115,536.82	49,481,626.83	10,315.893	36,176,792.474
VA	2017	52,718,115.27	47,518,905.34	5,790.729	32,376,190.346
VA	2018	57,217,428.96	45,409,589.92	8,875.318	34,399,464.849
VA	2019	60,573,674.52	30,747,889.53	2,342.786	31,030,890.35
VA	2020	65,931,048.77	25,363,195.49	1,525.061	32,756,022.322
VA	2021	55,180,481.6	28,656,693.55	1,320.841	28,623,529.826
VA	2022	51,288,748.01	31,633,767.86	1,320.212	27,251,719.101

Attachment 44

February 21, 2022

Voters would cut grocery tax; require vaccines for first responders, teachers, medical pros but not for students; keep teaching impact of racism on society, not ban CRT

Summary of Key Findings

1. A majority of Virginia voters prefer spending the state budget surplus on underfunded government services, such as education, public safety and social services (59%), rather than providing tax cuts or tax rebates (38%).
2. Voters overwhelmingly support cutting the 2.5% grocery tax, either by a total repeal (47%) or by giving low-income Virginians a tax credit (25%).
3. Voters support teaching how racism continues to impact American society (63% to 33%) and oppose a ban on the teaching of Critical Race Theory in public schools (57% to 35%).
4. Virginia voters support vaccine mandates for first responders (58%), teachers (57%) and medical providers (61%), while opposing mandates for elementary students (55%) and middle school students (51%). On masks in schools, voters say health data should be used to determine mask requirements (56%) versus leaving the decision to parents (41%).
5. Voters strongly support stationing a police officer in every school (70%).
6. On abortion, a plurality oppose a 24-hour waiting period (49% to 44%), while a majority oppose requiring an ultrasound (57% to 36%) and a ban on abortions at 6 weeks (58% to 33%).
7. Voters support the state's membership in the Regional Greenhouse Gas Initiative carbon cap-and-trade program (67% to 26%) and the Virginia Clean Economy Act (67% to 28%), a law requiring the state to generate 100% of its electricity from renewable energy by 2050.

Analysis

As the General Assembly passes crossover and moves into the second half of its 2022 session, Virginia registered voters are split on the direction of the state, their views of Governor Glenn Youngkin, and key agenda items before legislators. While Virginia voters

show support for some of Governor Youngkin's proposals, including a repeal of the grocery tax and placing a police or resource officer in public schools, a majority of registered voters do not support the governor's environmental policy proposals or a ban on the teaching of Critical Race Theory.

State of things: When asked about the direction of the Commonwealth, 45% say Virginia is headed in the right direction, while 41% say the wrong direction. Views about the right/wrong direction of the Commonwealth have remained relatively consistent over the last four years. After his first few weeks in office, Governor Youngkin's job approval is mixed, with 41% saying they approve of the job the governor is doing and 43% indicating disapproval; 16% say they don't know.

Differences are largely along partisan lines, with 80% of Republican voters saying Virginia is heading in the right direction, compared to 22% of Democrats and 45% of Independents. On Governor Youngkin's job performance, 85% of Republicans approve, while 81% of Democrats disapprove, and Independents are fairly split (42% approve, 36% disapprove, 22% don't know).

"In this highly polarized environment, we see partisans running to their corners on how they view the direction of the Commonwealth and the job of the governor," said Quentin Kidd, Academic Director of the Wason Center. "Youngkin's approval numbers are certainly lower than those of recent governors in Wason Center polling early in their term."

Direction of the country and presidential approval: Virginia voters are pessimistic about the direction of the country amid an ongoing pandemic and economic uncertainty. Only 22% of Virginia registered voters say the United States is headed in the right direction, compared to 67% percent who say the wrong direction. That is decidedly more pessimistic than over the past four years. President Biden's job approval numbers reflect this overall discontent, with 40% saying they approve of his job performance, compared to 53% who disapprove; 7% say they don't know. A year ago, Biden's approval among Virginia voters stood at 57%.

"Virginian's views have soured markedly on the direction of the country compared to a year ago when they are more optimistic after President Biden's election," said Kidd. "That pessimism is also reflected in Biden's dramatic drop in approval."

Taxes and the budget: Governor Youngkin has proposed to repeal the state's 2.5% grocery tax. In this survey, 47% of Virginia voters support a full repeal; 25% support granting a tax credit for low-income residents to offset the grocery tax; 24% say the grocery tax should remain as is.

With the state budget showing a significant surplus, a majority of Virginia voters would prioritize spending the surplus on underfunded government services, such as education, public safety and social services (59%), while 38% say the surplus should go back to Virginia citizens in the form of tax cuts or tax rebates.

Climate change: On environmental issues associated with renewable energy and climate change, Virginia voters show concern and support for government policy to address those concerns.

Most voters said potential climate change effects are having an impact on Virginia. On sea level rise, 44% of voters see major impact, 30% see minor impact, 20% see no impact and 7% say they don't know. On harm to wildlife and ecological systems, 46% see major impact, 31% see minor impact, 17% see no impact and 7% don't know. On hurricanes, floods and other extreme weather, 41% see major impact, 35% see minor impact, 23% see no impact and 2% don't know. As to long periods of hot weather, 41% see major impact, 34% see minor impact, 24% see no impact and 2% don't know.

A majority of Virginia voters say climate change should be either a top priority (34%) or a medium priority (32%) for the governor and General Assembly, while 33% indicate the issue should be a low priority (22%) or not a priority at all (11%). "It's not surprising to see

many Virginia voters say climate change should be a priority for their state government," said Rebecca Bromley-Trujillo, Research Director of the Wason Center. "Sea level rise, harm to ecosystems and extreme weather largely accord with scientists' expectations of climate effects here."

Governor Youngkin proposes to repeal the Virginia Clean Economy Act, a law passed in the Democratic-controlled legislature in 2020 and signed by Governor Ralph Northam that would require electric utilities in the state to produce 100% of their energy from renewable resources by 2050. Two-thirds (67%) of Virginia voters surveyed support this law, while just over a quarter (28%) oppose it. By a similar margin (67% to 26%), voters support another environmental policy targeted by the Youngkin administration, the Regional Greenhouse Gas Initiative, under which Virginia participates in a carbon cap-and-trade program with other states to reduce carbon pollution.

Teaching about race; stationing police in public schools: Virginia voters largely support teaching how racism continues to impact American society today (63% support/strongly support to 33% oppose/strongly oppose). In addition, a majority oppose a government ban on the teaching of Critical Race Theory in Virginia public schools (57% oppose/strongly oppose to 35% support/strongly support). While Critical Race Theory is currently not specifically taught in K-12 public schools in the state, the topic gained political traction during the 2021 gubernatorial campaign and Governor Youngkin signed an executive order banning its teaching on his first day in office. Demonstrating how politically charged the specialized term has become, differences in this survey emerge primarily along partisan lines, with Democrats heavily opposing a ban (82% oppose/strongly oppose) and Republicans supporting a ban (63% support/strongly support). While a majority of both white and Black voters oppose a ban, significant gaps are apparent (73% of Black voters and 53% of white voters oppose a ban; 19% of Black voters and 42% of white voters support a ban).

A large majority of Virginia voters support Governor Youngkin's proposal to require the placement of a police or resource officer in every Virginia public school (70% support/strongly support to 25% oppose/strongly oppose).

Abortion: Some Virginia Republican lawmakers proposed to reinstate restrictive abortion laws that were repealed under Democratic control in 2020, including a law mandating a 24-hour waiting period before a woman could have an abortion and a law requiring a woman to undergo an ultrasound before having an abortion. A plurality of Virginia voters oppose the 24-hour waiting period requirement (49% oppose/strongly oppose to 44% support/strongly support) and a solid majority oppose an ultrasound requirement (57% oppose/strongly oppose to 36% support/strongly support). A comparably large majority also oppose a ban on abortions once a fetal heartbeat is detected around the 6th week of pregnancy (58% oppose/strongly oppose to 33% support/strongly support).

COVID-19 vaccination and mask requirements: A majority of Virginia voters support vaccine requirements for people in jail or prison (57%), first responders (58%), members of the U.S. military (58%), teachers (57%), medical providers (61%), and members of Congress (56%). Virginia voters are split on vaccine requirements for college students (50% yes to 48% no), federal government employees (50% yes to 48% no), organizations/businesses with federal government contracts (48% yes to 50% no), state government employees (50% yes to 48% no), and high school students (49% yes to 49% no). A slight majority oppose a vaccine requirement for middle school students (47% yes to 51% no) and a larger majority oppose a vaccine requirement for elementary school students (42% yes to 55% no).

On masking in public schools, a majority of Virginia voters indicate that school mask requirements should be determined by health data and information from health experts (56%) versus a decision left to parents (41%). This result runs counter to a law just passed by the 2022 General Assembly and signed by Governor Youngkin allowing parents to opt their children out of mask mandates rather than leave the decision to local school boards.

Medical Aid and Dying: A majority of Virginia voters support allowing a mentally capable adult with a terminal disease the right to request and obtain medication to end their life (64% agree/strongly agree). Virginia voters are even more supportive of this allowance for a mentally capable adult with a terminal disease who has less than six months to live (66% agree/strongly agree).

Survey Questions

Q1: Overall, would you say things in the COMMONWEALTH OF VIRGINIA are heading more in th

	All	Rep
Right	45	80
Mixed	10	5
Wrong	41	13
Don't Know/ref (vol)	4	2
Trends:	Feb. 2021	Nov. 2020
Right	47	48
Mixed	8	7
Wrong	42	47
Dk/ref (vol)	5	2

Survey Demographics : Survey Demographics n=701

EDUC: Could you tell me the highest level of school or college you had the opportunity to complete:	
High school or less	55
College or more	45
HISPANIC: Do you consider yourself to be Hispanic or Latino?	
Yes	5
No	94
RACE: Do you consider yourself to be:	
White	70
Black or African American	19
Other	11
RELIG: What is your religious preference, are you Protestant, Roman Catholic, Jewish, Muslim, another religion, or no religion?	
Protestant	27
Christian (non-specific)	21
Catholic	13
Jewish	2
Muslim	1
Other	11
None	22
IDEOL: When it comes to your ideology, would you consider yourself to be a…	
Very conservative	4
Conservative	20
Moderate	34

How the survey was conducted:

The results of this poll are based on 701 interviews of registered Virginia voters, conducted January 26 – February 15, 2022. Percentages may not equal 100 due to rounding. The margin of error for the whole survey is +/-4.2% at the 95% level of confidence. This means that if 50% of respondents indicate a topline view on an issue, we can be 95% confident that the population's view on that issue is somewhere between 54.2% and 45.8%. The margin of error for subgroups may be higher. All error margins have been adjusted to account for the survey's design effect, which is 1.3 in this survey. The design effect is a factor representing the survey's deviation from a simple random sample and takes into account decreases in precision due to sample design and weighting procedures. In addition to sampling error, the other potential sources of error include non-response, question wording, and interviewer error.

The data reported here are weighted using an iterative weighting process on region, age, race, sex, and education to reflect as closely as possible the demographic composition of registered voters in Virginia. Parameters for the weights used in this survey come from the 2020 Census, 2017 and 2019 American Community Survey, and the Census Bureau's Population Estimates Program (PEP).

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REPORT A PROBLEM

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Attachment 45

JANUARY 27, 2023

State of the Commonwealth 2023

Virginians Give Governor Solid Marks, Think Commonwealth Doing Alright; Give President Low Marks, Think Country Heading in Wrong Direction; Prefer Governor Stay Right Here in the Commonwealth

Same Dynamic on Education: 41% of Virginians Give Their Local Public Schools an “A” or “B” Grade; Only 13% Grade National Public Schools that High

Virginians Support: Recreational Marijuana Sales; Staying in the Regional Greenhouse Gas Initiative; Parental Approval For Changes in Student Gender ID; And Narrowly Back Income Tax Cut; But Oppose Corporate Tax Cut Proposal

Summary of Key Findings

1. A plurality of Virginians think the Commonwealth is headed in the right direction (45% to 37%), while 50% approve of the job Governor Youngkin is doing. Still, Virginians prefer that the Governor not run for president (59% to 29%).
2. Virginians are pessimistic about the direction of the country (19% right direction to 73% wrong direction); dissatisfaction is reflected in Biden’s approval rating (38% approve to 57% disapprove).
3. Virginia voters support recreational marijuana sales (60%) and allowing any interested localities to host casinos should their residents approve one in a referendum (55%).
4. Virginia voters strongly support staying in the Regional Greenhouse Gas Initiative (66%) and support the Virginia Clean Economy Act (62% to 33%).
5. 41% of Virginians Give Their Local Public Schools an “A” or “B” Grade; Only 13% Grade National Public Schools that High.
6. Virginia voters also show support for requiring parental approval for K- 12 students to be referred to by a different pronoun from their birth certificate (59% to 36%).
7. Virginians would prefer to keep state abortion laws as is (43%) compared to 29% who would prefer less restrictive laws and 23% who want more restrictive laws on abortion.
8. A plurality of Virginia voters support lowering Virginias individual income tax rate (48% to 43%), but oppose a cut to Virginia’s corporate income tax rate (57% to 37%).

Analysis

As the General Assembly enters its third week of the 2023 session, Virginia registered voters are relatively split on a number of key agenda items before state legislators. Virginia voters show support for some of Governor Youngkin's policies, including narrow support for a reduction in the state income tax and requiring parental approval for students to be referred to by a different pronoun from their birth certificate in K-12 public schools. On the other hand, a majority of registered voters do not support the governor's environmental policy proposals, abortion restrictions, or his corporate tax cut proposal. Still, half of Virginia voters approve of the job Governor Youngkin is doing and are more optimistic about the direction of the Commonwealth than the state of the nation.

State of things: When asked about the direction of the Commonwealth, 45% say Virginia is headed in the right direction, while 37% say the wrong direction, with 11% are mixed. Views about the right/wrong direction of the Commonwealth have remained relatively consistent over the last four years. Governor Youngkin's job approval remains steady from nearly a year ago at 50%, while 36% indicate they disapprove and 14% say they don't know.

Differences are largely along partisan lines, with 67% of Republican voters saying Virginia is heading in the right direction, compared to 23% of Democrats and 47% of Independents. On Governor Youngkin's job performance, 83% of Republicans approve, while 74% of Democrats disapprove; 54% of Independents signal their approval.

Still, Virginians prefer that the Governor not run for president in 2024. 59% say Governor Youngkin should not run for president in 2024 while 29% say he should. Another 8% are unsure while 5% say they don't know. A plurality of Republicans (46%) support a presidential run, while 38% of Republicans do not like the prospect. Independents are opposed to a run with 58% saying don't do it. Democrats, as would be expected, are do not want to see the Governor run, with 82% opposed.

Direction of the country and presidential approval: Virginia voters continue to be pessimistic about the direction of the country. Only 19% of Virginia registered voters say the United States is headed in the right direction, compared to 73% percent who say the wrong direction; 6% are mixed and 2% say they don't know. President Biden's job approval numbers reflect this overall discontent, with 38% saying they approve of his job performance, compared to 57% who disapprove; 5% say they don't know. A year ago, Biden's approval among Virginia voters stood at 40%.

K-12 education: When it comes to grading Virginia K-12 public schools, Virginians view their local schools more positively than the nation's. 41% give Virginia schools an A or B grade, while 28% give a C, followed by 13% D and 9% F. When asked about the nation's public schools only 13% give an A or B grade with most giving public schools outside of Virginia a C (39%), D (20%), or F (15%).

Tax policy: Governor Youngkin's tax proposals receive mixed reviews. Virginians narrowly support his proposal to lower Virginia's top individual income tax rate from 5.75% to 5.5% (48% support, 43% oppose; 9% don't know). A majority oppose a cut to Virginia's corporate income tax rate from 6% to 5% (57% oppose to 37% support; 6% don't know).

Environmental Policy: Virginians continue to support remaining in the Regional Greenhouse Gas Initiative (RGGI) (66% to 24%; 10% don't know), a regional carbon cap and trade program joined by 11 states aimed at reducing greenhouse gas emissions.

While there are partisan differences on RGGI, a plurality of Republicans still support staying in the program (42% to 40%), while Democrats show considerable support (92% to 4 %); Independents also show support (62% to 29%). Younger Virginia voters show higher support than those 45+ (71% to 62%).

Virginians also continue to support the Virginia Clean Economy Act (62% support to 33% oppose; 6% don't know), a law passed in the Democratic-controlled legislature in 2020 and signed by Governor Ralph Northam that requires electric utilities in the state to produce 100% of their energy from renewable resources by 2050. This program has also been targeted for repeal by the Governor and Republican Virginia lawmakers.

Abortion: When asked about abortion policy in the Commonwealth, most Virginia voters believe abortion laws should remain as is (43%), followed by support for less restrictive laws (29%), and some support for more restrictive abortion laws (23%). Several bills that would require more restrictions on abortions have been proposed in the 2023 General Assembly session, and Governor Youngkin has called for a ban on abortions at 15 weeks with exceptions for life of the mother, rape and incest.

A similar number of partisans on both sides of the political aisle support keeping abortion law as is (45% of Democrats compared to 39% of Republicans and 46% of Independents). Still, partisan differences emerge with 44% of Republicans supporting more restrictive abortion laws compared to only 1% of Democrats and 26% of Independents. There is also a modest gender gap on this issue with 75% of women indicating they either want abortion laws to remain as is (45%), or laws to be less restrictive (30%). 68% of men support leaving laws as is (41%) or less restrictive (27%).

Marijuana and Casinos: Virginians support allowing the retail sale of recreational marijuana in Virginia (60% to 34%; 6% don't know). While Democrats show strong support (73% to 21%), Republicans are heavily split (44% support to 47% oppose). In addition, there is a clear age gap on this issue with those aged 18-44 showing higher support than 45+ (72% to 50%).

"Marijuana has proved to be a major topic of discussion in the current General Assembly session given the unusual nature of current Virginia law," said Rebecca Bromley-Trujillo, Research Director of the Wason Center. "As it stands, it is legal to possess and cultivate small amounts of marijuana, but retail sale is still not allowed. The Governor has largely shied away from answering questions about his stance, while both Democrats and Republicans have proposed a range of bills on the subject. It remains to be seen whether lawmakers can actually come to an agreement, however."

Currently, five Virginia localities have been given the opportunity to hold a referendum to allow for hosting a casino in their locality, and Virginia's first temporary casino opened in Bristol last year, with the first permanent casino opening in Portsmouth this year. Virginians now indicate they support allowing any interested localities to host casinos as well if their voters were to approve of one in a referendum (55% support to 38% oppose). Support is largely bipartisan with Independents indicating the highest levels of support at 59%, followed by 58% of Democrats and 50% of Republicans.

Survey Questions

Q1: Overall, would you say things in the COMMONWEALTH OF VIRGINIA are heading more in th

	All	Rep	
Right	45	67	
Mixed (vol)	11	7	
Wrong	37	22	
Don't know (vol)	8	4	

Q1 Q2 Q3 Q4 Q5 Q6 Q7 Q8 Q9 Q10 Q11 Q12 Q13 Q14 Q15

Survey Demographics : Survey Demographics n=1038

EDUC: Could you tell me the highest level of school or college you had the opportunity to complete:	
High school or less	55
College or more	45
Dk/ref (vol)	
HISPANIC: Do you consider yourself to be Hispanic or Latino?	
Yes	5
No	93
Dk/ref (vol)	2
RACE: Do you consider yourself to be:	
White	70
Black or African American	19
Other	11
RELIG: What is your religious preference, are you Protestant, Roman Catholic, Jewish, Muslim, another religion, or no religion?	
Protestant	33
Christian (non-specific)	17
Catholic	13
Jewish	1
Muslim	0
Other	9
None	22
Dk/ref (vol)	5
IDEOL: When it comes to your ideology, would you consider yourself to be a…	

Survey Demographics n=1038

How the survey was conducted:

The results of this poll are based on 1038 interviews of Virginia registered voters, including 231 on landline and 807 on cell phone, conducted January 13- January 23, 2023. Percentages may not equal 100 due to rounding. The margin of error for the whole survey is +/- 3.8% at the 95% level of confidence. This means that if 50% of respondents indicate a topline view on an issue, we can be 95% confident that the population's view on that issue is somewhere between 53.8% and 46.2%. The margin of error for subgroups may be higher. All error margins have been adjusted to account for the survey's design effect, which is 1.6 in this survey. The design effect is a factor representing the survey's deviation from a simple random sample and takes into account decreases in precision due to sample design and weighting procedures. Sub-samples have a higher margin of error. In addition to sampling error, the other potential sources of error include non-response, question wording, and interviewer error. The response rate (AAPOR RRI Standard Definition) for the survey was 11%. Five callbacks were employed in the fielding process. Live calling was conducted by trained interviewers at Christopher Newport University and Dynata. The data reported here are weighted using an iterative weighting process on region, age, race, sex, and education

to reflect as closely as possible the population of Virginia's registered voters. Parameters for the weights come from the 2020 Census and the 2021 American Community Survey 1-year Estimates.

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REPORT A PROBLEM

Attachment 46

DEQ
VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

State Air Pollution Control Board

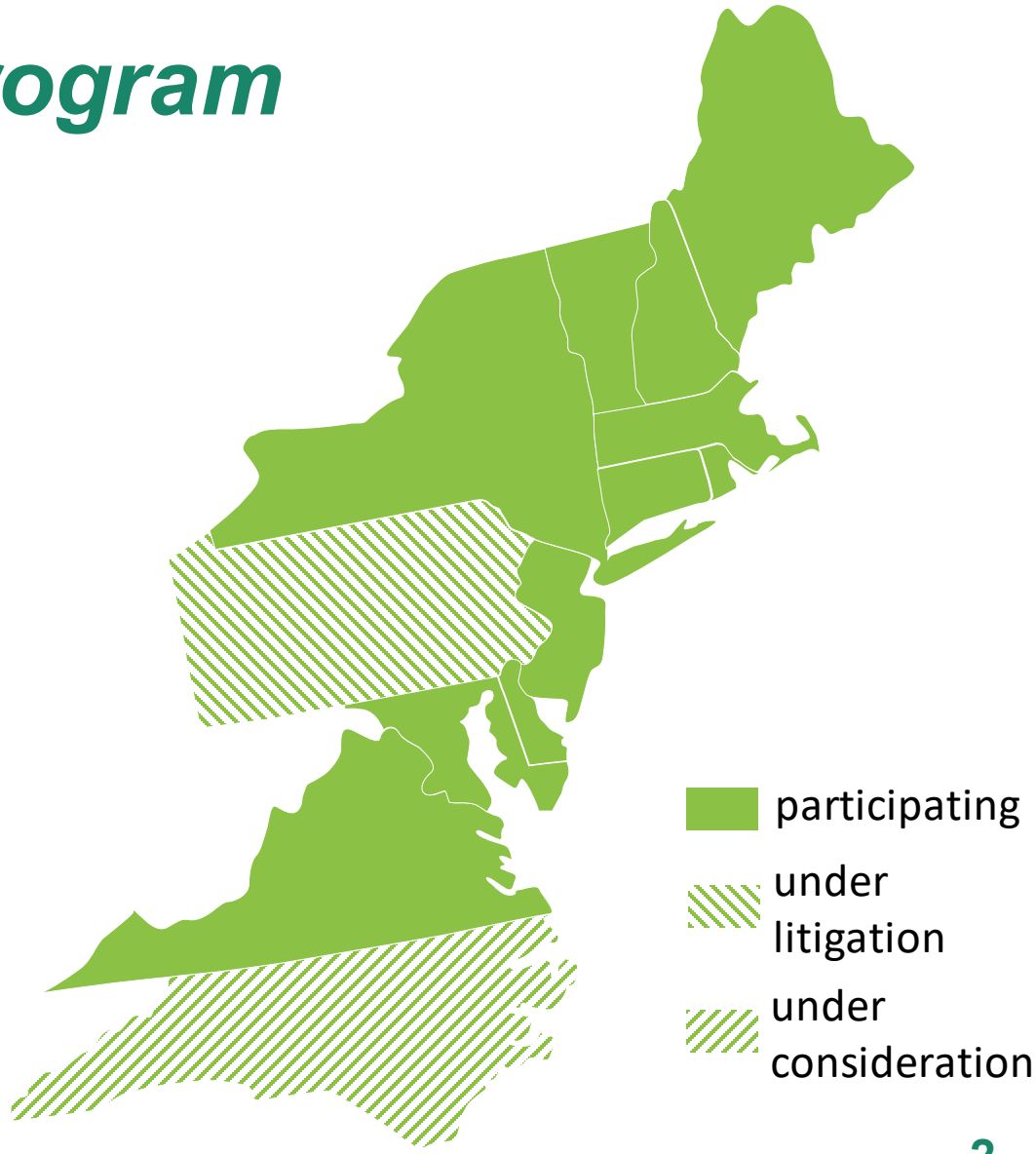
Proposed Regulation: Repeal CO_2 Budget Trading Program, 9VAC5 Chapter 140 (Rev. A22)

Travis A. Voyles
Acting Secretary of Natural and Historic Resources
December 7, 2022

Background—*The RGGI Program*

The Regional Greenhouse Gas Initiative (RGGI) is a carbon cap-and-trade program covering fossil fuel-fired electric generating units in 11 northeast and mid-Atlantic states

- CT, DE, MA, MD, ME, NH, NY, PA, RI, VA, VT
- NC (*considering*)
- PA (*on hold*)



Background—*The RGGI Program*

- All participating RGGI states regulate:
  - ***Fossil-fuel (carbon-based) emissions*** from ***electric generating units*** 25MW or greater
- Each CO_2 "Budget Source" must hold a CO_2 allowance for every ton of CO_2 emitted during a 3-year "control period"
  - Compliance determined by comparing number of tons of CO_2 emitted with number of allowances contained in facility's compliance account over 3-year control period
- CO_2 allowances are purchased in quarterly auctions run by RGGI, Inc.
  - Proceeds returned to states to be used for consumer benefit *or* strategic energy purpose
- RGGI in VA:
  - Existing industrial and biomass units exempted
  - Rule became effective July 10, 2020—First auction March, 5, 2021
  - 7 auctions to date with >40 million allowances sold and $452M returned to the state

Current Regulatory Framework

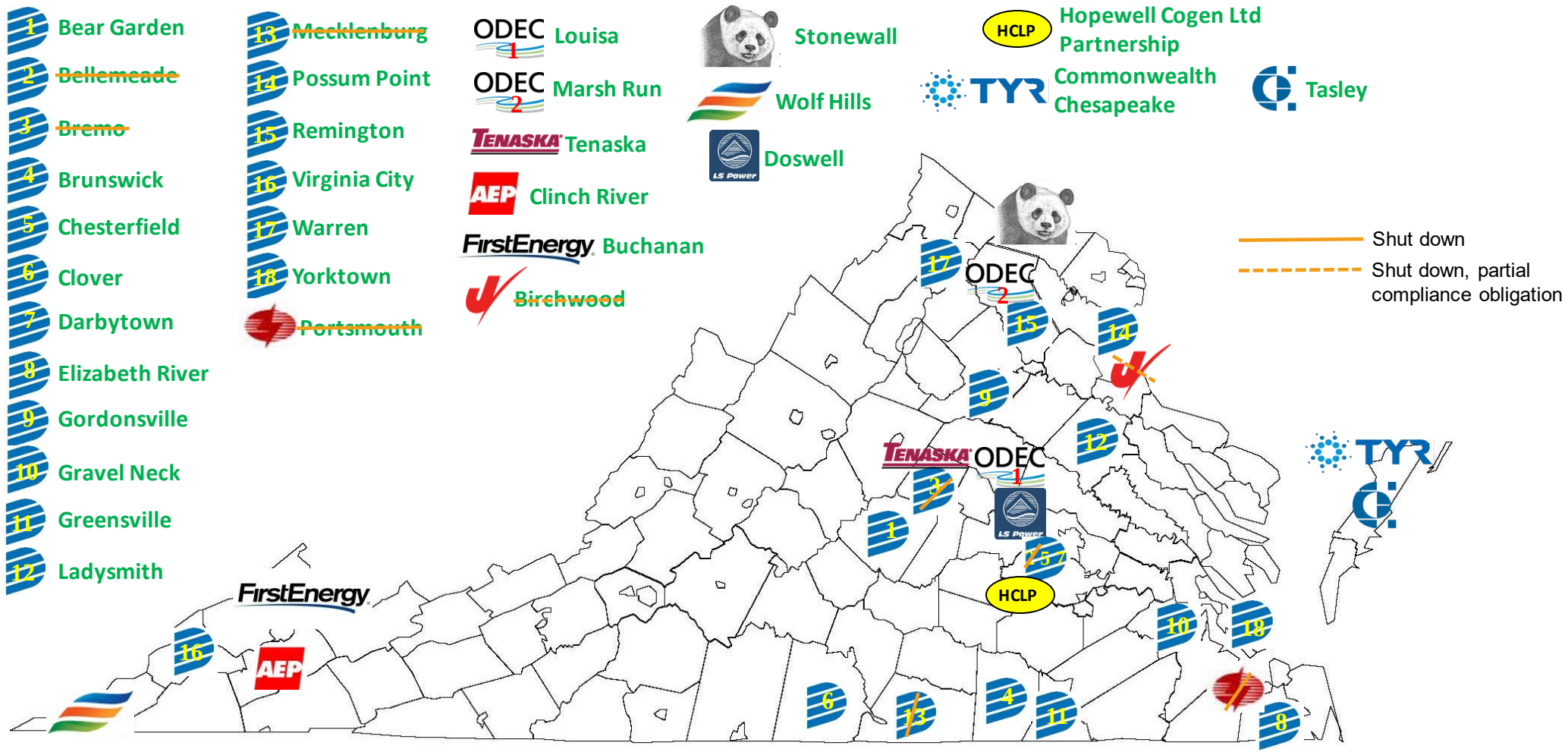
Virginia Clean Economy Act

- requires shift in generation mix to 100% renewable by 2050

Clean Energy and Community Flood Preparedness Act

- established mechanisms to join RGGI
- specified DCR/DHCD programs to receive funding

Regional Greenhouse Gas Initiative (RGGI)



Fossil fuel-fired electric generating units with ≥ 25 MW capacity

Youngkin Administration

January 2022 Governor's Executive Order 9 – *Protecting Ratepayers from the Rising Cost of Living due to the Regional Greenhouse Gas Initiative*

Directive—that SNHR and DEQ:

- Provide a full report re-evaluating the costs and benefits of participation in RGGI in view of all available data.
- Take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment.
- Notify RGGI of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

March 2022 DEQ Report – *VA Carbon Trading Rule and RGGI Participation: Costs and Benefits*

March 2022 DEQ Report—*Key Findings*

- RGGI operates as a direct tax because all fees paid are passed through to ratepayers.
- Utilities are not penalized for failure to meet RGGI CO_2 emissions since they can pass on the costs to the ratepayers, and consumers are unable to avoid these costs since they do not have the opportunity to switch electric providers.
- Other states designed their systems to provide rebates to their ratepayers. Virginia consumers were originally told the program would return proceeds to the ratepayers but the General Assembly chose to disburse the funds through grant programs.
- The costs of compliance with the trading rule and participation in RGGI are materializing in higher electricity rates for all ratepayers, and future rate increases due to RGGI are expected and will be tied to the allowance prices which are difficult to predict.

The Path Forward—*Process*

Regulatory Action

- Repeal the trading rule and end VA's participation in RGGI
- Full Administrative Process Act (APA) process
- Notice of Intended Regulatory Action (NOIRA)—Proposed—Final
  - Transition section added at the end of rule

Timing—Complete repeal by the end of 2023

- 3-year compliance/control period of RGGI
- Contractual agreement with RGGI Inc.

Provides For Stable Withdrawal for Regulatory Certainty

- Smooth and orderly exit
- Avoid market disruptions

The Path Forward—*Rationale*

Increasing Energy Costs

Virginia's Energy Future

- No Control of RGGI Costs

RGGI Effectiveness and Burden

- Direct Consumer Tax
- Duplicative Transition Cost of RGGI
- Emissions Reductions without RGGI

Standard (*Full*) Regulatory Development—*NOIRA Stage*

- Agency submitted NOIRA for executive branch review
- Agency authorized by Governor to submit NOIRA for publication.
- NOIRA is published in the *Virginia Register*
- 30-day public comment period (Town Hall and email)
  - Began September 26, 2022
  - Ended October 26, 2022
  - Summary and response to comments found in Agency Background Document

NOIRA Process—*Comments*

- 838 Town Hall Comments
  - General—51 supportive, 730 against
  - Against—
    - 11 substantive (CBF, Ceres, Virginia Clinicians, Nature Conservancy, Climate Action Alliance of the Valley VaLCV, C2ES, VCN, CCA)
    - 6 local governments (Cities of Arlington, Alexandria, Hampton, Fairfax, Charlottesville; Town of Colonial Beach)
- Emails—225 against the proposal sponsored by VaLCV with about 16 general comments against
- Written substantive comments from:

pro	con
Dominion	ACEEE
VMA	ALA
	EDF
	Hampton Roads Planning District Commission
	International Emissions Trading Association
	James River Association
	New Virginia Majority
	Northern Virginia Regional Commission
	SELC
	Virginia Energy Efficiency Council

Standard (*Full*) Regulatory Development—*Proposed Stage*

- Agency considers public comment and drafts proposed regulation
- Board adopts proposed regulation
- Agency submits proposed regulation for executive branch review
- Agency is authorized by Governor to submit proposed regulation for publication
- Proposed regulation is published in the *Virginia Register*
- 60-day public comment period

Standard (*Full*) Regulatory Development—*Final Stage*

- Agency considers public comment and drafts final regulation
- Board adopts final regulation
- Agency submits proposed regulation for executive branch review
- Agency is authorized by Governor to submit final regulation for publication
- Final regulation is published in the *Virginia Register*
- Regulation becomes effective

Regulatory Process—*What's Next*

- **December 7, 2022—Proposed regulation presented to the Board**
  - If approved, proceed to:
- Executive Review—
  - Department of Planning and Budget
  - Secretary of Natural and Historic Resources
  - Office of Regulatory Management
  - Governor
- Publication in *Virginia Register*
  - Commences a 60-day public comment period
- Final Stage—Board meeting in 2023
- Regulation effective 30 days after publication in the *Virginia Register*

Adoption Process

- The regulation is subject to the state administrative procedures for full process regulations under the Administrative Process Act (*NOIRA—Proposed—Final*)

- *Today's Action*—Approve request to propose for public comment the repeal of Part VII of 9VAC5-140, CO_2 Budget Trading Program to be issued for public comment in accordance with the APA

RGGI is a Bad Deal for Virginia

RGGI Is Not Working—Whether you agree with the principals of a cap and trade regime, the way RGGI is set up for VA does not work.

Burden—Costs passed on to the consumer without any change in behavior by the electricity providers due to VA's regulatory structure.

Abandoned Responsibility—Forfeited our important decision-making rights to Northeastern states who have more say over our energy policy than any VA consumer.

Funding—Virginians don't need a regressive energy tax through RGGI to fund important programs. These are not the goals that RGGI was meant to achieve.

***Action*—Complete repeal by end of 2023, ending VA's participation in RGGI.**

Department Recommendation

- That the board authorize the department to issue the proposal for public comment in accordance with the APA.

Attachment 47

28 Oct, 2022

Virginians rally for RGGI carbon market as Pennsylvania cools to idea

Author **Karin Rives**

Theme **Energy**

Workers at a Consol Energy mine in Pennsylvania. The coal producer was one of several companies to seek a court injunction barring the state from participating in Regional Greenhouse Gas Initiative carbon auctions.
Source: S&P Global Commodity Insights

Over the past month, 838 people and organizations in Virginia weighed in on Gov. Glenn Youngkin's initial proposal to pull the state from the Regional Greenhouse Gas Initiative. More than 95% said the Commonwealth should remain part of the 12-state carbon market.

The level of support for the program reflects the popularity of flood mitigation and coastal resilience projects that are paid for with the proceeds from the RGGI allowance auctions, said Cale Jaffe, a University of Virginia law professor.

"These are bread-and-butter infrastructure projects with money going directly to local governments," Jaffe said in an interview. "If Virginia were to withdraw from RGGI, how do you fill this budgetary hole and fund programs local governments have come to depend upon?"

Another factor likely driving public engagement is that half of the $452.2 million raised by the RGGI auctions for Virginia since March 2021 was earmarked for energy-efficiency upgrades for low-income residents, Jaffe said.

By the time the one-month comment period closed Oct. 26, the vast majority of respondents to the Youngkin administration's notice of intended regulatory action had turned thumbs down on the move, a tally by S&P Global Commodity Insights showed. Youngkin, a Republican, is expected to push forward with the rulemaking to take the state out of RGGI once the public comments have been reviewed.

The public support for the RGGI in Virginia stands in contrast to the heated debate in Pennsylvania, one of the nation's largest producers of natural gas and coal. Legal challenges from legislators, coal companies, plant owners and trade unions halted implementation of the RGGI program, the signature climate initiative of outgoing Pennsylvania Gov. Tom Wolf, a Democrat.

Data accessed Oct. 25, 2022.
Map credit: Arleigh Andes.
Source: RGGI Inc.
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In both states, whether utility carbon emissions will be capped under the RGGI, and for how long, is uncertain. On-again, off-again state energy policies make planning for the future difficult for power companies, said William Shobe, a professor of public policy and economics with the University of Virginia who helped to design RGGI's carbon allowance auctions ahead of the market's 2008 launch.

"There is risk in any market — what we don't need is the additional risk of big policy changes," Shobe said in an interview. "We would have to replace the [carbon] market with something that is less flexible, and it's going to cost firms to change their capital outlays over the next several years should policies change."

RGGI faces uphill battle in Pennsylvania

Under RGGI, power companies that own fossil fuel plants with a capacity of at least 25 MW are required to buy greenhouse gas emission allowances, or credits, for each short ton of carbon their plants emit. The companies purchase the allowances at quarterly auctions or from a secondary market to comply with their state's emissions cap, which is tightened over time.

The RGGI held its first auction in 2008. Greenhouse gas emissions in participating states have dropped by more than 50%, twice as fast as in the nation as a whole, since the program's inception, according to an RGGI fact sheet published in September 2021.

The RGGI market mechanism financially rewards power producers with cleaner plants while placing a growing economic burden on those that do not transition away from fossil fuels, pushing down emissions. That message has not gone over so well in Pennsylvania, which is the nation's second-largest producer of natural gas and third-largest producer of coal, according to the U.S. Energy Information Administration.

Neither candidate in Pennsylvania's high-profile race for governor has embraced membership in RGGI, now in limbo. Josh Shapiro, the state's attorney general, is running as a Democrat. Shapiro has suggested that his

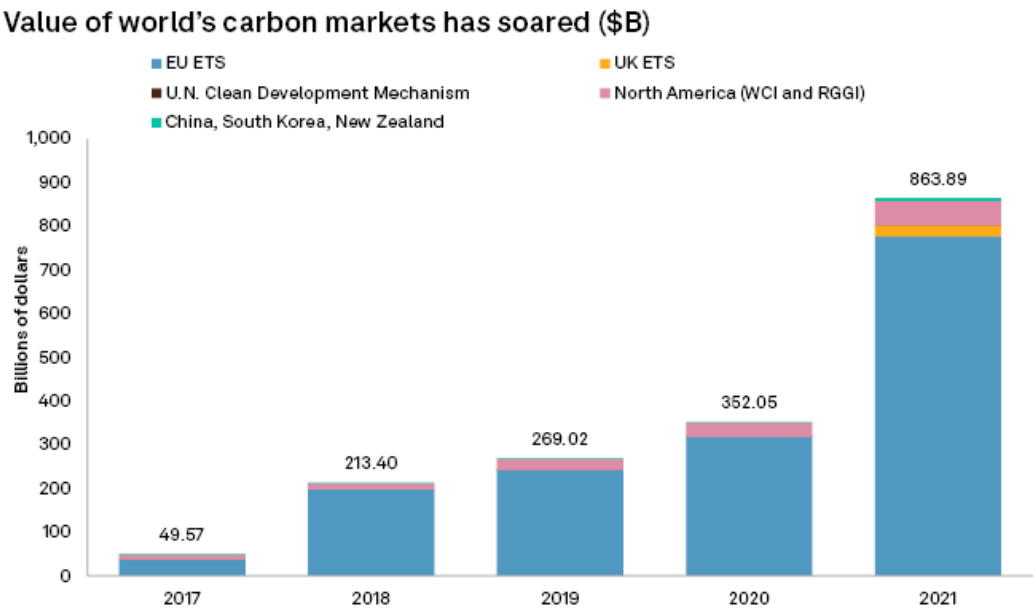
energy plan might not have room for RGGI, should he be elected.

Polling this summer by Muhlenberg College found that while Pennsylvanians expressed concern over climate change, 86% of state residents think that drilling for natural gas is either very or somewhat important to the state's economy.

The state officially entered the carbon market in July but had to withdraw from its first auction after a state court issued an injunction stalling the plan. The Pennsylvania Supreme Court in August declined to overrule that decision until the lower-court trial scheduled for mid-November has concluded.

That means Pennsylvania will probably also miss its second auction in December, along with millions in revenue, said Rob Altenburg, energy center director with environmental advocacy group PennFuture.

"Assuming the [state Department of Environmental Protection] prevails in the legal challenges, we expect continued legislative attempts to derail the program in the new session," Altenburg wrote in an email. "So a lot will depend on the political landscape after the election."



Data as of May 17, 2022.
Value of compliance cap-and-trade markets. Voluntary carbon offset market not included here.
WCI stands for Western Climate Initiative, RGGI for Regional Greenhouse Gas Initiative and ETS for Emission Trading System.
Values originally reported in euros were converted to U.S. dollars as of the last trading day of each year.
Source: Refinitiv

Virginia gearing up for a fight

In addition to private citizens, a number of Virginia cities, faith leaders and environmental groups such as the Southern Environmental Law Center, the National Parks Conservation Association, and the Sierra Club weighed in with comments to defend the RGGI cap-and-trade program.

"Communities across Virginia need to plan for, mitigate, and build resilience to the climate change impacts being felt today," wrote Justin Wilson, mayor of Alexandria, Va. "The dedicated source of funding for the Community Flood Preparedness Fund provided by Virginia's participation in the Regional Greenhouse Gas Initiative is critical to our ability to do the work of flood mitigation and resilience planning in our communities."

Supporters of the governor's plan said RGGI amounts to a tax on consumers when utilities pass on compliance costs to ratepayers, an argument Youngkin has also used. Others called it "government overreach" or questioned the RGGI's impact.

"Having power companies buy credits to meet greenhouse initiatives misses the point of reducing emissions," one commenter wrote. "I'd love to see the number of [kilowatt-hours] used each month by all these people who support keeping this initiative. These are probably the same people driving big SUVs while protesting for clean air."

Ultimately, it is not the share of comments filed against the governor's plan but the quality of comments that the state takes into consideration, said Mike Dowd, director of air and renewable energy for the Virginia Department of Environmental Quality.

"We take comments very seriously, especially if they bring up issues we may not have thought about," Dowd said in an interview. "We look for substance, not for a percentage."

The agency expected a large number of comments knowing that RGGI has public support, said the state's air quality chief, who has been with the agency since 2008. "A lot of people feel passionate about this, obviously," Dowd said.

Should the rulemaking make it through another comment period and be finalized in late 2023, as the Youngkin administration hopes, a court battle will likely ensue in Virginia, Jaffe predicted. Legal experts have argued that Youngkin cannot use executive orders or rulemakings to undo state law.

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Attachment 48

Analysis of the Public Health Impacts of the Regional Greenhouse Gas Initiative, 2009–2014

Prepared by:
Abt Associates
55 Wheeler Street
Cambridge, MA 02138

January 2017

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Acronyms and Abbreviations

BenMAP	Benefits Mapping and Analysis Program
CAA	Clean Air Act Amendments of 1990
CAMD	Clean Air Markets Division
CO_2	Carbon dioxide
COBRA	Co-Benefits Risk Assessment
EE	Energy efficiency
eGRID	Emissions and Generation Resources Integrated Database
EGU	Electric generating unit
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
ER	Emergency room
GHG	Greenhouse gas
Hg	Mercury
IPCC	Intergovernmental Panel on Climate Change
MAPS	Multi-Area Production Simulation
MW	Megawatt
MWh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NARSTO	North American Research Strategy for Tropospheric Ozone
NEI	National Emissions Inventory
NESCAUM	Northeast States for Coordinated Air Use Management
NO_x	Nitrogen oxides
PM	Particulate matter
$PM_{2.5}$	Fine particulate matter
RE	Renewable energy
RFF	Resources for the Future
RGGI	Regional Greenhouse Gas Initiative
S-R	Source-Receptor
SO_2	Sulfur dioxide
TAG	Technical Advisory Group
WTP	Willingness-to-pay
ZEV	Zero emission vehicle

Acknowledgements

This report is an independent, retrospective study of the public health impacts of the Regional Greenhouse Gas Initiative (RGGI) over its first six years of implementation (2009-2014). Abt Associates relied on modeling results from two Analysis Group reports, *The Economic Impacts of the Regional Greenhouse Gas Initiative on Northeast and Mid-Atlantic States*, covering the 2009-2011 and 2012-2014 periods. Abt is grateful to Analysis Group for providing access to results of their dispatch modeling, which served as a foundation of our analysis of the impacts of RGGI on air emissions, air quality, and public health.

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- **George (Tad) Aburn,** Air Director, Maryland Department of the Environment
- **Paul Hibbard,** Principal, Analysis Group
- **Dr. Patrick Kinney,** Professor of Environmental Health, Boston University
- **Dr. Paul Miller,** Deputy Director, Northeast States for Coordinated Air Use Management (NESCAUM)
- Additional anonymous contributors also provided informal input and review.

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The findings of this independent study are based solely on the analysis and judgment of Abt Associates and do not necessarily reflect the views of the TAG members, Laurie Burt, or our funders.

About Abt Associates

Abt Associates is a mission-driven, global leader in research, evaluation, and program implementation in the fields of health, social and environmental policy, and international development. Known for its rigorous approach to solving complex challenges, Abt is regularly ranked as one of the top 20 global research firms and one of the top 40 international development innovators. The company has multiple offices in the United States and program offices in more than 40 countries.

Abt's experts in climate change, clean energy, and public health include economists, public health experts, epidemiologists, natural scientists, data scientists, attorneys, and others. In addition, Abt economists and public health experts support the U.S. Environmental Protection Agency's (EPA's) efforts to develop, maintain, and update the Benefits Mapping and Analysis Program (BenMAP) and the Co-Benefits Risk Assessment (COBRA) tools, both of which are utilized in this analysis.

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Executive Summary

Purpose of this Study

This independent study provides an analysis of the public health impacts of the Regional Greenhouse Gas Initiative (RGGI) over its first six years of implementation (2009 to 2014). RGGI is the nation's first regional regulatory program designed to reduce greenhouse gas (GHG) emissions from large electric power plants, and builds from a long and successful tradition in the Northeast states of using market-based programs to cost-effectively reduce air pollution. Since RGGI started in 2009, the program has raised nearly $3 billion to support the RGGI states' investments in energy efficiency, renewable generation, and other public benefit programs, and these states are on track to achieve reductions of GHG emissions of 45 percent below 2005 levels by 2020.

Because "criteria" air pollutants[1] are co-produced along with GHG emissions from fossil-fuel power plants, RGGI is also expected to drive reductions in these air pollutants and their adverse effects on human health. The objective of this independent study is to provide a *retrospective* analysis of the impacts of an existing GHG reduction program—RGGI—on air quality and public health.

Using publicly available, peer-reviewed air quality and public health models and historical data characterizing RGGI's actual performance during the program's first two compliance periods (covering 2009 to 2014), we addressed the following questions in this analysis:

- Did RGGI result in measurable changes in emissions of criteria air pollutants and air quality?
- If so, how did changes in air quality resulting from RGGI affect public health and to what degree?
- What were the spatial and temporal patterns to changes in air quality and public health due to RGGI implementation?
- Will health benefits from RGGI's first two compliance periods be replicated in the future?

Key Results and Findings

The RGGI program improved air quality throughout the Northeast states and created major benefits to public health and productivity, including avoiding hundreds of premature deaths and tens of thousands of lost work days. RGGI's impact on electricity markets resulted in significant reductions in key air pollutants with adverse effects on human health. Over the first six years of the program, RGGI avoided hundreds of cases of premature deaths, heart attacks, hospitalizations, and emergency room (ER) visits; tens of thousands of lost work days, and hundreds of thousands of cases of restricted activity days due to poor air quality. Table 1 summarizes cumulative avoided health and productivity effects associated with RGGI's first two compliance periods.

[1] "Criteria air pollutants" refer to the six most common air pollutants in the United States: carbon monoxide (CO), lead, ground-level ozone (O_3), nitrogen oxides (NOx), particulate matter (PM), and sulfur dioxide (SO_2). The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS), which are maximum allowable concentrations for these pollutants that are protective of public health.

Table 1. Summary of Cumulative RGGI Health Benefits, 2009 to 2014

Avoided Health Effects	**Avoided Mortality**		
	• 300–830 premature adult deaths		
	Avoided Morbidity		
	• 35–390 non-fatal heart attacks		
	• 420–510 cases of acute bronchitis		
	• 8,200–9,900 asthma exacerbations		
	• 13,000–16,000 respiratory symptoms		
	Other		
	• 180–220 hospital admissions		
	• 200–230 asthma ER visits		
	• 39,000–47,000 lost work days		
	• 240,000–280,000 days of minor restricted activity		
Value of Avoided Health Effects	**Low**	**Central**	**High**
	$3.0 billion	$5.7 billion	$8.3 billion

Source: Abt Associates analysis (2017).

Notes: The total value of avoided health effects is the sum of health benefits in states participating in RGGI and in neighboring northeastern states, based on a 3 percent rate of discount. Values are in 2015 dollars.

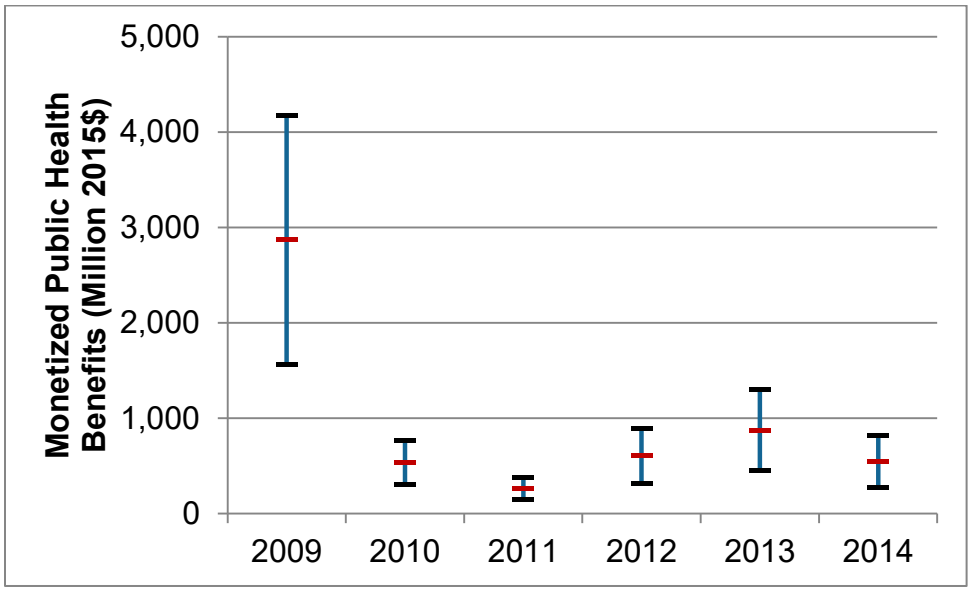
The economic value of RGGI's health and productivity benefits is estimated at a cumulative $5.7 billion ($3.0 billion low-end, $8.3 billion high-end). Avoided cases of premature deaths due to reduced levels of fine particulate matter $PM_{2.5}$ account for the majority of RGGI's monetized health benefits. However, other important benefits to the region's economic productivity and quality-of-life include more than 39,000 avoided lost work days and at least 240,000 avoided days with restricted activities (e.g., exercising outdoors) due to poor air quality.

Estimated benefits to health are positive in every state in the Northeast region (including RGGI and certain neighboring states)), and in almost every year of the study period. States with the highest total monetized health benefits over RGGI's first six years include: Delaware, Maryland, New Jersey, New York, and Pennsylvania. Sizeable benefits also occur in Massachusetts, Connecticut, and New Hampshire. Benefits in Rhode Island, Vermont, and Maine are smaller in magnitude compared to those in states with larger populations, but are relatively consistent over the study period. Overall, health benefits estimated for the first compliance period are higher than for the second period.

The largest annual improvements in air quality and health benefits from RGGI are in 2009 and 2013. The largest single-year benefits in health due to RGGI occur in 2009 (shown in Figure 1). This result is consistent with RGGI's two observed effects on wholesale power markets: 1) changes in power prices to absorb CO_2 allowance costs, which results in shifting electricity dispatch from higher- to lower-carbon sources, and 2) investments in energy efficiency that reduce electricity demand, fossil fuel-based generation, and emissions. There is also some evidence that power plant owners, anticipating the requirements of the program, may have taken early action to reduce CO_2 emissions immediately before and after the start of the program in 2009. Energy efficiency investments were comparatively high in this year as well. The combination of higher prices and energy efficiency investments, together with early action, likely account for the largest single-year emission reductions and health benefits across the six year period. Similarly, higher benefits in 2013 most likely correspond to higher relative investments in

energy efficiency and renewable energy in that year, and also reflect energy savings accruing from efficiency investments made in prior years.

Figure 1. Annual Health Benefits due to RGGI, 2009 to 2014

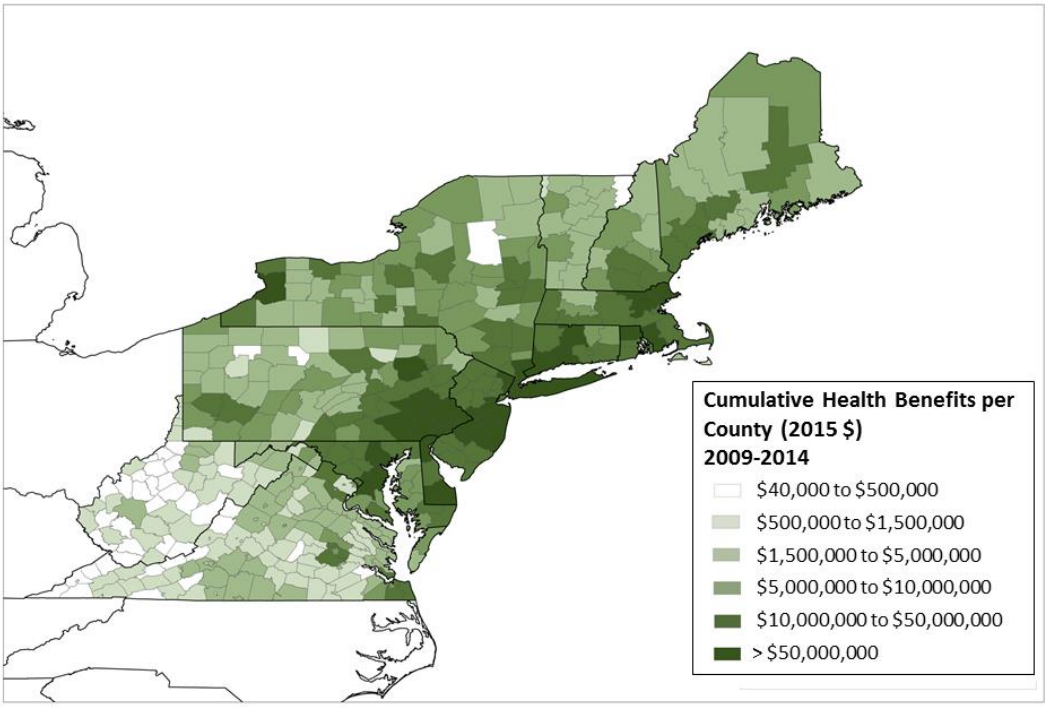


Source: Abt Associates analysis (2017).

Note: Value of annual health benefits is the sum of health benefits to RGGI states and neighboring northeastern states, based on a 3 percent rate of discount.

Multiple states in the mid-Atlantic and New England regions experienced significant health benefits from RGGI-induced changes to air quality which originate in the RGGI states. Due to regional transport of air pollutants, our modeling shows that states with densely populated areas located directly downwind of key coal-fired power plants experienced substantial health benefits, regardless of whether they participate in RGGI. As shown in Figure 2, Pennsylvania experienced the most significant benefits overall from RGGI due to reductions in emissions from Maryland's (and to a lesser extent Delaware's) large coal plants. The District of Columbia, Virginia and West Virginia also experienced modest health benefits from emissions reductions occurring in RGGI states. Similarly, emissions reductions due to RGGI from coal plants in western New York, Massachusetts, and New Hampshire create health benefits not only in those states, but also in Rhode Island, Vermont, and Maine.

Figure 2. Cumulative Health Effects of RGGI, 2009 to 2014



Source: Abt Associates analysis (2017).

A small number of legacy coal plants, particularly in the mid-Atlantic RGGI states, account for the majority of RGGI's health benefits. Coal-fired power plants have the highest emission rates of SO_2, which is the primary contributor to ambient $PM_{2.5}$ levels and risks to health. So, reductions in SO_2 emissions by coal plants account for the majority of health benefits. Of the RGGI states, Maryland has the most significant footprint of older coal-fired power plants and the largest inventory of SO_2 emissions. RGGI-induced changes in generation and emissions from five of Maryland's coal plants alone account for roughly 62 percent of SO_2 reductions in 2009, and 55 percent of cumulative SO_2 reductions from RGGI's first two compliance periods (2009 to 2014).

If coal plants in RGGI states retire as planned in the near future, reductions of air pollutants and annual health benefits resulting from the RGGI program will likely level off. However, additional health benefits will occur as energy demand from other sectors—transportation and buildings—shifts onto a cleaner grid in RGGI and neighboring states. As noted above, RGGI-induced changes at a relatively small number of coal plants drive a high proportion of RGGI's total reductions in key air pollutants and health benefits. However, a number of older coal-fired power plants in RGGI states driving many of the health benefits presented in this analysis are scheduled to retire within the next five years (e.g., Chalk Point in Maryland, Brayton Point in Massachusetts). As such, the fleet of power plants in RGGI states will on average be cleaner in the near future than the current fleet, so that future RGGI-induced reductions in generation are likely to result in less average annual health benefits going forward. However, states will be able to move energy use from other sectors, such as transportation and heating, to this cleaner grid. This process, known as "electrification," can further reduce air pollutants resulting in significant health benefits. For example, transitioning the light-duty vehicle fleet to about 65 percent zero-emission vehicles (ZEVs) by 2050 in eight northeastern states could result in emission reductions that generate nearly $12 billion in health benefits (American Lung Association of California 2016).

RGGI-funded investments in energy efficiency strategically targeted to address daily air quality goals during high-electricity demand periods can generate additional health benefits. The scope of this analysis addressed only annual changes in average $PM_{2.5}$ concentrations. However, air quality in a given location can be highly variable over the course of a year, and a single short-term exposure to high $PM_{2.5}$ concentrations can lead to more severe health outcomes than multiple exposures to low $PM_{2.5}$ concentrations. To the extent that RGGI states' future investments in energy efficiency programs can effectively target peak load on days with high electricity demand, RGGI can further reduce the number of low air quality days and thereby generate additional health benefits in the future.

Estimates of RGGI's health benefits presented in this study are likely conservative, and also do not include the value of other co-benefits associated with reductions in air pollution, such as improved ecosystem services. Health benefits resulting from energy savings associated with RGGI states' efficiency investments that persist beyond 2014 and from reductions in ozone were beyond the scope of this study, but could be significant. In addition, additional benefits to terrestrial and aquatic ecosystems resulting from reductions in sulfur and nitrogen deposition are not included in this analysis.

Approach

The analytic approach used in this study for estimating RGGI's impact on emissions, air quality, and public health consisted of three sequential steps described below:

1. **Estimate annual changes in electric generation and emissions of air pollutants at power plants as a result of RGGI implementation from 2009 to 2014.**

   The RGGI program created changes to annual electricity generation, the mix of power plants (and fuels) dispatched to meet electric demand, and associated changes in emission profiles through its two direct effects on the electricity market: 1) Owners of large fossil-fuel power plants purchase CO_2 allowances to meet RGGI's emissions cap, and then build the costs of these purchases into wholesale power prices. In this way, purchases of CO_2 allowances result in shifts in power production from higher- to lower-carbon generation sources; and 2) Participating RGGI states' investments of proceeds from allowance auctions into energy efficiency measures and renewable generation result in reductions in overall electricity demand and increase the capacity for low- or zero-carbon electricity, respectively.

   We used results from electricity dispatch modeling to determine annual changes in generation (in megawatt-hours (MWh), at the plant level) due to the RGGI program and also for a counterfactual scenario representing the world without RGGI. Using EPA historical data on actual power plant-level emissions (and emissions rates), we then used the incremental difference in plant-level output due to RGGI, calculated associated changes in SO_2 and NOx emissions, and aggregated these emission changes at the county level. These results became the inputs to the air quality modeling conducted in the second step of this analysis.

2. **Estimate annual changes in air quality at the county level associated with changes in sulfur dioxide (SO_2) and NO_x emissions from power plants, by year.**

   To estimate the air quality impacts of RGGI using annual county-level emission changes calculated under the first analytic step, we used EPA's Co-Benefits Risk Assessment (COBRA) model. COBRA is a free, screening-level tool that assists government agencies and others in assessing the benefits of clean energy and climate mitigation policies by estimating the effects of changes in air pollutant

emissions on ambient air concentrations of fine particulate matter ($PM_{2.5}$). Using the estimated incremental change in county-level emissions of NO_x and SO_2 due to RGGI that we calculated under Step 1, we performed a COBRA modeling run for each individual year from 2009 to 2014. Outputs from the COBRA modeling step consist of annual changes in ambient $PM_{2.5}$ levels in each county in RGGI and adjacent non-RGGI states, and become the inputs to the modeling of associated health impacts under Step 3.

3. **Assess public health impacts associated with changes in air quality due to RGGI implementation from 2009 to 2014.**

   To quantify and value the public health impacts associated with RGGI's first six years, we used EPA's BenMAP. The BenMAP model uses data describing population, background levels of health outcomes in populations, and economic values for health effects from literature to estimate the number and economic value of health impacts resulting from changes in air quality. We used the county-level changes in ambient $PM_{2.5}$ levels generated by COBRA as inputs to BenMAP. BenMAP then calculated annual health benefits from RGGI's relative effect on ambient $PM_{2.5}$ for 2009 to 2014.

In addition, we conducted sensitivity analysis to address uncertainties surrounding data, assumptions, and key modeling relationships. Specifically, we applied a sensitivity factor of 50 percent to discount estimates of health benefits for states not participating in the RGGI program, to account for a gap in information about changes in air emissions that may have occurred in these states as a result of RGGI. In addition, outputs from the BenMAP model also reflect uncertainties in the assumed relationship between reductions in exposures of human populations to key air pollutants and health outcomes, especially premature mortality. Finally, we did not quantify other benefits outside the scope of this analysis, such as health benefits associated with reductions in ozone and RGGI-induced energy savings occurring after 2014, or improved ecosystem health. As such, the benefits presented here can be considered a conservative representation of the co-benefits of the RGGI program to human health and ecosystems.

Overview of Analysis

The northeastern U.S. states have a long track record of implementing market-based environmental programs to improve air and water quality. The first of these programs—the Acid Rain Program[2]—was established under Title IV of the 1990 Clean Air Act Amendments (CAA) and required power plants to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), the primary contributors to acid rain formation. The Acid Rain Program also established a trading system that enabled regulated firms to exchange allowances or permits to meet emissions goals at the lowest possible total cost. The Acid Rain Program was an environmental success story: SO_2 emissions from electric power plants declined by more than one-third—from 15.9 million to 10.2 million tons—between 1990 and 2004 (U.S. EPA, 2016c), despite a 25 percent increase in electricity generation from coal-fired power plants over the same period (Schmalensee and Stavins, 2013). The program's cap of nearly 9 million tons of SO_2 emissions from the power sector was achieved by 2007, and declined further to 5 million tons by 2010.

Another important hallmark of the Acid Rain Program was that its environmental goals were achieved with low costs of implementation relative to net benefits. Electric utilities regulated under this program achieved the goals for emissions reductions at a significantly lower cost than was projected at the outset of the program. Costs projected before implementation of the Acid Rain Program were over $2.7 to $6.2 billion (U.S. EPA, 2011b). However, retrospective studies found that actual annual costs ranged from $0.5 billion to $2 billion, and total annual benefits ranged from $59 billion to $116 billion (Schmalensee and Stavins, 2013).

The Northeast region's second experience with implementing market-based trading to address air pollution from large power plants was the NO_x Budget Program, which was initiated by 12 states in order to attain compliance with National Ambient Air Quality Standards (NAAQS) for ozone. The NO_x Budget Program incorporated key "lessons learned" by regulators in state environmental agencies and utilities from implementing the Acid Rain Program and similar environmental trading programs. In particular, this program was the first time that a group of states worked together to establish their own multi-state program, in lieu of the U.S. Environmental Protection Agency (EPA) promulgating regulations to address summertime ozone exceedances in the region (Pew Center, 2003).[3] Another key feature of the NO_x Budget Program was that the states developed a "model rule," a set of core requirements that each state needed to adopt to ensure a well-functioning program.[4]

The Regional Greenhouse Gas Initiative (RGGI) built from and further leveraged the northeastern states' hands-on experience with implementing multi-state, market-based programs. RGGI is the nation's first regional market-based regulatory program designed to reduce greenhouse gas (GHG) emissions from the electric sector. Beginning in 2003, Governor Pataki of New York invited environmental and public utility

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2 40 CFR Parts 72 through 78.

3 The first example of a local regulator establishing a cap-and-trade program for meeting air quality goals was the RECLAIM program established by South Coast Air Quality Management District to reduce emissions of criteria air pollutants in the Los Angeles County basin.

4 The "model rule" was created by a task force that included representatives from all states in the Ozone Transport Commission and EPA.

staff from 10 northeastern states[5] to begin working together on the scope and design of a regional system to reduce carbon dioxide (CO_2) emissions from power plants. The program's scope includes new and existing fossil-fuel electric generating units (EGUs) with capacity of 25 megawatts (MW) or more.[6] In late 2008, the 10 RGGI states held the first allowance auctions in preparation for RGGI's January 2009 start date. As of this writing, the RGGI program has an eight-year track record (i.e., January 2009–December 2016) and the following achievements:

- Raised nearly $3 billion in auction proceeds for participating state investments in energy efficiency (EE), renewable energy (RE), and other public benefit programs;
- Is on track for reducing GHG emissions 45 percent below 2005 levels by 2020;[7]
- Generated net savings in consumers' electricity and energy bills through substantial investments in demand-side efficiency;
- Performed over 30 quarterly allowance auctions in a well-functioning marketplace.

For these reasons, RGGI has been held up as a blueprint for other programs and certainly helped to inform the EPA's proposal for the Clean Power Plan, a national-level GHG program for the electric power sector. However, the direct results of the RGGI program are only a part of the story—its influence in the northeastern United States extends beyond reductions in GHG emissions.

1.1 Objectives of Analysis

While the RGGI states' objectives for the program were primarily focused on reducing GHG emissions, increasing the role of renewable energy, and reducing imports of fossil fuels, RGGI and similar clean energy programs also have other, less direct effects on the economy, the environment, and public health. A broader evaluation of the full suite of RGGI's impacts will provide policymakers and the public with a more complete picture of the program's effectiveness.

Analysis Group conducted the first set of studies that analyzed other impacts of RGGI beyond its primary goal of reducing GHG emissions from large power plants. In 2011 and 2015, after RGGI's first three-year compliance periods ended, Analysis Group performed retrospective analysis of RGGI's impact on electricity markets, costs to power producers, impacts on electricity bills of consumers and businesses, and impacts on economic output of the RGGI states. Both of these studies demonstrated that RGGI implementation created positive and substantial benefits to the regional economy over the six years since its inception. This positive economic story resulted in part because the RGGI states opted to invest nearly all of the proceeds received from RGGI allowance auctions back into the economy. The RGGI states did

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5 At the outset of the program, Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont all participated in RGGI. New Jersey left the RGGI program in 2011; nine states currently participate in the RGGI program.

6 Owners of new and existing power plants regulated under RGGI must acquire a tradeable allowance for each short ton of CO_2 emitted. Owners of EGUs retire their allowances at the end of a three-year "control period" (also "compliance period").

7 New Jersey left the RGGI program in late 2011, and the emissions cap and goals were readjusted accordingly.

this through expansion of energy efficiency programs, new renewable power projects, assistance to low-income consumers of energy bills, and other programs designed to reduce GHG emissions.

Because Analysis Group's studies of RGGI economic impacts were retrospective, they used historical, real-world data on actual program performance and market outcomes to generate insights into net economic benefits of the program. Retrospective studies like these can provide especially useful inputs to RGGI's regular three-year program review process, during which policymakers in the RGGI states consider adjustments to fine-tune the program's effectiveness and net benefits.

The relationship between programs that improve air quality and public health is well-established: in numerous studies of the costs and benefits of CAA, EPA estimated that improved air quality results in public health benefits that exceed the costs of achieving air quality targets by a 30:1 ratio (U.S. EPA 2011c). Most of the economic value of CAA benefits (about 85 percent) are attributable to health benefits; specifically, reductions in premature deaths associated with reductions in ambient particulate matter (U.S. EPA 2011c). In 2020 alone, EPA estimates that the CAA will prevent over 230,000 early deaths.

Because air pollutants with adverse effects on human health are often co-produced with CO_2 when electric power is generated from fossil-fuel power plants, RGGI and similar GHG programs for the power sector are expected to drive some reductions in levels of these air pollutants. Numerous studies have explored the impact of *future* policies and programs aimed at reducing GHG emissions on air pollution and public health. To date, however, few studies have investigated public health impacts of *existing* GHG reduction programs such as RGGI.

To better understand the impacts of RGGI on public health, Abt Associates conducted an independent study of the program's effect on emissions and air quality during the first two compliance periods—2009 to 2014. The objective of our study is to apply credible, widely accepted tools, methods, and publicly available data to answer the following questions:

- Did the first six years of RGGI's implementation result in measurable changes in emissions of criteria air pollutants and air quality?
- If so, how did changes in air quality resulting from RGGI's implementation affect public health and to what degree?
- What spatial and temporal patterns are evident in changes in air quality and health outcomes resulting from RGGI?
- Will health benefits from RGGI's first two compliance periods be replicated in the future?

1.2 Scope of Analysis

Retrospective analysis. Many policy analyses are *prospective*, that is, they project incremental impacts that are anticipated to occur in the future as a result of policy, relative to a baseline or counterfactual case representing the world without the policy. However, our analysis is *retrospective*, i.e., it looks backward at incremental outcomes and impacts that occurred from 2009 to 2014 as a result of RGGI. Our analysis benefits from having actual historical data for many variables used in the analysis. Specifically, we used EPA datasets to describe actual annual NO_x and SO_2 emissions, annual generation levels, and emission rates at the individual plant level for all power plants located in the RGGI states. In addition, we rely upon

results from electricity market dispatch modeling runs conducted by Analysis Group in 2011 and 2015; these modeling runs also incorporated actual historical data for fuel prices, costs of emissions allowances, power plant retirements and additions, and other electricity market factors (e.g., transmission constraints).[8]

Scope. Below we provide additional detail on the scope of this analysis and how the analytic scope may influence results.

Timeframe: The timeframe addressed by this analysis encompasses the entirety of RGGI's first two compliance periods, i.e., 2009 to 2011, and 2012 to 2014, respectively. This is a somewhat limited picture of the incremental impacts of RGGI in one respect: proceeds invested by the states into energy efficiency programs during the 2009 to 2014 timeframe will continue to generate energy savings *after* 2014, because the incremental energy savings from high-efficiency devices funded through these programs typically persist for 10 to 15 years after installation. Our omission of these additional energy savings in this analysis was due to data and modeling limitations.[9] As such, our estimates likely *underestimate* reduced emissions associated with avoided electricity generation due to RGGI, and thus underestimate health benefits.

Air quality modeling: To estimate changes in air quality associated with RGGI implementation, we use EPA's Co–Benefits Risk Assessment model (COBRA) (U.S. EPA, 2015c). COBRA includes a reduced-form air quality model that estimates the effect of emission changes on formation of fine particulate matter (referred to as $PM_{2.5}$).[10] COBRA does not estimate changes in ozone, another air pollutant with adverse health effects. Thus, this analysis does not estimate benefits associated with ozone reductions, although they are expected to occur. Changes in levels of ambient particulate matter, however, are typically the largest factor driving human health benefits.[11] Therefore, we expect COBRA to capture a large share of RGGI's impacts on health in the region, although our estimates will be conservative.

Geographic scope: The geographic scope of this analysis includes changes in electricity market outcomes and associated emissions changes occurring in states participating in the RGGI program. Because changes in emissions that take place within RGGI states will affect air quality and public health in "downwind" states, we also report results for states within the region affected by the program but not currently participating in RGGI.

Other benefit categories: There are additional benefits associated with reducing emissions of CO_2 and other air pollutants that are outside of the scope of this study. First, this study does not cover the potential health benefits of mitigating climate change, such as fewer heat-related illnesses or cases of vector-borne disease.

The scope of this study also excludes reductions in regional haze, largely caused by $PM_{2.5}$ pollutants scattering the sunlight, which impairs visibility and also contributes to harmful respiratory impacts. EPA

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8 Descriptions of these dispatch models and results from Analysis Group's use of them in their analyses of RGGI's regional economic impacts can be found in Analysis Group (2011, 2015).

9 Additional detail on tools and methods used for air quality modeling is provided in Section 2.

10 Fine particulate matter is less than 2.5 micrometers in diameter.

11 Anenberg et al. (2010) estimated that in North America annual mortalities due to anthropogenic $PM_{2.5}$ are approximately three to four times greater than annual mortalities due to anthropogenic ozone.

requires reductions in haze through the Regional Haze Rule to improve visibility in federally protected national parks and wilderness areas (U.S. EPA, 1999).

Benefits to ecosystems and natural resources represent a final category of benefits not captured in this analysis. RGGI-related reductions in the deposition of sulfur and nitrogen compounds in the environment, which have adverse effects on terrestrial and aquatic ecosystems, would improve the health of these ecosystems (Miller, 2011). These environmental impacts can also affect human livelihoods and public health.

This remainder of this report is organized as follows:

- **Section 2:** This section provides additional context for changes in air quality and public health as co-benefits of climate mitigation and clean energy policies.
- **Section 3:** This section describes the analytic approach, data, and methods used to estimate changes in emissions, air quality, and public health associated with RGGI implementation from 2009 to 2014.
- **Section 4:** This section provides results of the analysis and discussion of key findings, policy implications, and uncertainties.
- **Appendices:** The appendices include additional background and technical detail describing the air quality and public health modeling tools used in this analysis. Detailed state-level results are available in Appendix E, which is available for download as a separate document. .

2. Co-Benefits of Climate Mitigation and Clean Energy Programs

In addition to reducing GHG emissions, climate mitigation and clean energy programs such as RGGI can create an array of other public benefits—often referred to as "co-benefits"—in the energy system, the environment, and the economy.[12] These co-benefits can figure importantly in the analysis of total benefits and overall policy effectiveness. For example, the Intergovernmental Panel on Climate Change (IPCC) finds that the near-term public health co-benefits from climate mitigation may offset a significant portion of total mitigation costs (IPCC, 2013).

Table 2 lists key categories of co-benefits resulting from climate and clean energy policies, which are described below:

- **Energy system co-benefits** result from investments that improve the overall performance and efficiency of electricity grid operations. Energy system co-benefits include reduction in electricity losses over transmission lines (typically up to 10 percent), and alleviating load at times of peak demand. In addition, a more efficient system featuring a higher level of distributed generation resources (in contrast to large centralized power plants connected by long-distance transmission lines) can increase the resilience of the grid to severe storms while also enhancing reliability.
- **Economic co-benefits** associated with a more efficient and decentralized electricity grid include: direct savings on energy bills by consumers and businesses; reductions in high costs of serving peak load; and reducing imports of fossil fuels and thereby retaining more capital in the region. Regional employment and economic development can benefit directly from the growth of clean energy industries. In 2016, the 9 RGGI states plus New Jersey ranked in the top 20 states in the United States for total capital investments in energy efficiency, renewables, clean technology ventures, and policies supporting energy efficiency and clean technology (Clean Edge 2016). In Massachusetts for example, clean energy employment grew more than eight times faster than the overall growth rate across all Massachusetts industries from 2011 to 2013 (Massachusetts Clean Energy Center, 2013).
- **Public health co-benefits** result from improvements to environmental endpoints—airsheds and watersheds—as pollutant loadings to air and water are reduced via lower energy demand and shifting of energy generation to cleaner sources. Emissions of fine particulate matter, which can be emitted directly from sources or formed secondarily through atmospheric chemical processes, can cause premature death, heart attacks, and strokes, as well as harmful effects on the respiratory system, including asthma attacks. This category of co-benefit is the primary focus of this report; however, as noted below, reductions in emissions of mercury (Hg) and ozone-forming NO_x can also result from policies targeting GHGs and are also beneficial to human health.
- **Environmental co-benefits** of climate and clean energy programs arise from reducing total energy demand and shifting generation to cleaner, more efficient sources of generation. Key environmental benefits from clean energy include reductions in emissions of air pollutants and their precursors (e.g.,

[12] These positive outcomes are often referred to as "co-benefits" because they are additional to the direct program objective of reducing carbon emissions and increasing efficiency and renewable energy. While this list of co-benefits associated with climate mitigation and clean energy programs is fairly comprehensive, more in-depth information can be found in the following sources: U.S. EPA (2011a) and Regulatory Assistance Project (2014).

particulate matter (PM), NO_x, SO_2, ozone, air toxics, and Hg), which results in reduced formation and deposition of these pollutants.

Ozone is formed by emissions of nitrogen oxides reacting in the presence of sunlight with volatile organic compounds in the air. Ozone's effects on human health include increased frequency of asthma attacks, shortness of breath, aggravated lung disease, damage to lungs through long-term exposure, additional hospitalizations and emergency room (ER) visits, and premature deaths. Coal-fired power plants and other stationary sources (e.g., incinerators) can also release mercury into the air. Airborne mercury emissions then settle into terrestrial and aquatic ecosystems and can be converted to methylmercury, a harmful neurotoxin. Methylmercury enters into the food chain, where it builds up ("bio-accumulates") in fish through their diet. As a result, the most common source of human exposure to methylmercury occurs through fish consumption.

Table 2. Benefits of Climate Mitigation and Clean Energy Policies

	Energy System	Economic	Public Health	Environmental
Direct benefits	Reduced electricity load and peak demand Increase in distributed generation Reductions in imports of fossil fuels	Energy savings from energy efficiency investments Increased economic activity for energy efficiency and renewable energy sectors	**Improved air quality from co-reductions in emissions of criteria air pollutants**	Reductions in CO_2 emissions and impacts of climate change Reductions of nitrogen, sulfur, mercury, and other air toxics in air and watersheds
Indirect benefits	Fuel diversification Increased energy security Improved grid resilience and reliability	Job creation in clean energy and energy efficiency sectors	Fewer incidences of respiratory and cardiovascular diseases and premature deaths from improved air quality Improved water quality	Improved terrestrial and aquatic ecosystem health Improved visibility Potential reductions in water intake by power plants

Sources: IPCC (2014); U.S. EPA (2011a); Union of Concerned Scientists (2013).

2.1 Regional Economic Impacts of RGGI

The RGGI program had a net positive impact on the regional economy of the Northeast over the initial six years of program implementation. This outcome reflects key policy decisions made regarding the sale of nearly $2 billion of CO_2 allowances to owners of fossil-fuel power plants. The decision by RGGI states to auction nearly all emission allowances, rather than distributing allowances directly to regulated entities for free, is a unique and defining feature of the RGGI program.[13] As a result of this key design feature, the states were able to use proceeds collected from allowance auctions during the 2009 to 2014 period for

[13] Emission allowances were allocated freely to regulated utilities under both the Acid Rain and NO_x Budget Programs.

public benefit purposes. Each state determined how to deploy its share of RGGI proceeds based on its own legislative and public policy priorities.[14] During the first two compliance periods of RGGI, states participating in the program invested a substantial portion of auction proceeds into energy efficiency programs, renewable energy generation, and other GHG reduction programs. By investing proceeds into programs that themselves generate additional reductions in GHG emissions and energy demand, the RGGI states essentially leveraged revenues from proceeds to amplify the magnitude of GHG emissions reductions achieved, beyond those that would have been achieved solely from placing a cost on the right to emit CO_2.

Analysis Group's empirical review of the RGGI states' strategic investments of proceeds from RGGI auctions into efficiency and clean energy programs showed that these programs generated economic benefits to consumers and business, and an increase in output and employment in the region. Using six years of actual data gathered from RGGI's first two compliance periods, Analysis Group conducted consecutive analyses (in 2011 and 2015, respectively) that tracked individual RGGI states' investments of proceeds on an annual basis, and then estimated direct and indirect impacts of the program on the regional economy. In its calculations, Analysis Group accounted for the effects of the RGGI program on power system dispatch, net energy costs to consumers, revenues to electric generators, and overall state economic performance (Analysis Group, 2011, 2015).

Both the 2011 and 2015 Analysis Group studies arrived at similar conclusions: RGGI states' investments of auction proceeds into energy efficiency, renewable energy, climate mitigation activities, and direct rebates resulted in positive impacts on the region's economic value-added and employment. Analysis Group found that in the period 2009–2011, economic value-added in the RGGI states totaled $1.6 billion, and found similarly that economic value added in the period 2012–2014 was $1.3 billion. These benefits were found to be due in part to the states' combined investments in energy efficiency and clean energy in both compliance periods (Analysis Group, 2011, 2015). Additional economic value-added translated to an average of $31 per capita in the region for the 2012 to 2014 compliance period alone (Analysis Group, 2015). In addition, employment in the RGGI states increased by more than 16,000 job-years in the period 2009–2011, and 14,000 job-years from 2012 to 2014. Table 3 summarizes these key findings from Analysis Group's studies.

Table 3. Summary of RGGI Economic Benefits, 2009 to 2014

Type of Economic Impact	First Compliance Period (2009-2011)[1]	Second Compliance Period (2012-2014)[2]
Total value-added to RGGI states	$1.6 billion	$1.3 billion
Net job creation[3]	16,000 job-years	14,200 job-years

Source: Analysis Group (2011, 2015).

1. Reported in 2011 dollars, on a net present value basis using a discount rate of 3 percent.

[14] The 2005 Memorandum of Understanding and the 2008 revised Model Rule designate a minimum of 25 percent of each state's allowance proceeds to go to a "consumer benefit or strategic energy purpose." In practice, states are vastly exceeding the required minimums for public benefit or energy purposes. Allowances are apportioned through state allowance budgets, which are largely based on historical power plant emissions in each state and an agreed-upon formula. The allotment of allowances then determines the magnitude of each state's proceeds from the allowance auction.

2. Reported in 2015 dollars, on a net present value basis using a discount rate of 3 percent and reflects adjustments for inflation.
3. A job-year is defined as providing full-time job for one year.

Analysis Group's studies confirm that investments in energy efficiency acted as an important economic multiplier. Adopting energy efficiency measures reduces the total demand for electricity generation, and reduces wholesale electricity prices through impacts on system dispatch. Consumers who reduce their electricity use by becoming more efficient save on monthly energy bills. On a macroeconomic scale, reduced demand through energy efficiency and expansion of renewables lowers the total amount paid to fossil-fuel generators located outside of the RGGI region. Overall, higher per-kilowatt costs passed on to electricity consumers to cover the costs of CO_2 allowance purchases in the short term are offset by energy bill savings resulting from RGGI proceeds investments within the region (Analysis Group, 2015).

In the next section, we provide additional context for this evaluation of RGGI's impact on air quality and public health.

2.2 Impacts of Climate and Clean Energy Programs on Air Quality and Public Health

Policies and programs that reduce GHG emissions from electric power plants and other fossil-fuel stationary sources (e.g., industrial boilers) can also achieve important public health benefits. Fossil-fuel power plants emit not only CO_2 but also other air pollutants with proven adverse effects on human health, including fine particulate matter ($PM_{2.5}$), NO_x, SO_2, Hg, and air toxics.

Power plant emissions of NO_x, SO_2, and other pollutants impact air quality at the local level to varying degrees, depending on characteristics of the source,[15] spatial distribution of emissions, and local meteorological conditions that dictate the formation of pollutants with adverse health effects. The burning of fossil fuels releases SO_2, which contributes to the formation of acid rain and $PM_{2.5}$ and can cause impact human respiratory and cardiovascular systems. NO_x emissions also form $PM_{2.5}$ and ground-level ozone, thereby exacerbating negative impacts of this air pollutant. Fine particulate matter composed of airborne solid particles and liquid droplets carries a mixture of soot, smoke, toxic metals, and many other harmful chemical pollutants; inhaling the fine particulate matter can lead to severe health effects. By entering the lungs and even the bloodstream, these air pollutants can cause or aggravate respiratory conditions and cardiovascular diseases and can lead to premature death.

Below we describe results of recent prospective analyses of the impacts of national- and regional-level climate mitigation and clean energy policies on air quality and public health.

Findings from Recent Studies

A number of recent studies have demonstrated the link between policies aimed at reducing GHG emissions, associated changes in levels of air pollutants, and resulting impacts on human health. Generally, these studies rely upon a multi-step analytic approach that is similar to the process employed

[15] For example, the height of the emissions stack affects dispersion and formation of air pollutants, particularly through wind patterns that contribute to interstate transport of air pollutants. While tall stacks may be designed to limit negative air quality impacts on the local community, the overall pollution does not diminish, it is only transported downwind.

in this analysis (described in Section 3). The first step is to estimate the impact of a proposed policy on emissions of criteria air pollutants. Then, air quality models are applied to estimate how changes in emissions of air pollutants resulting from the policy modify levels of air pollution in specific geographic locations. Finally, a public health model is used to estimate changes in public health outcomes associated with air quality changes to specific geographic locations and populations, and the associated economic value of health impacts.

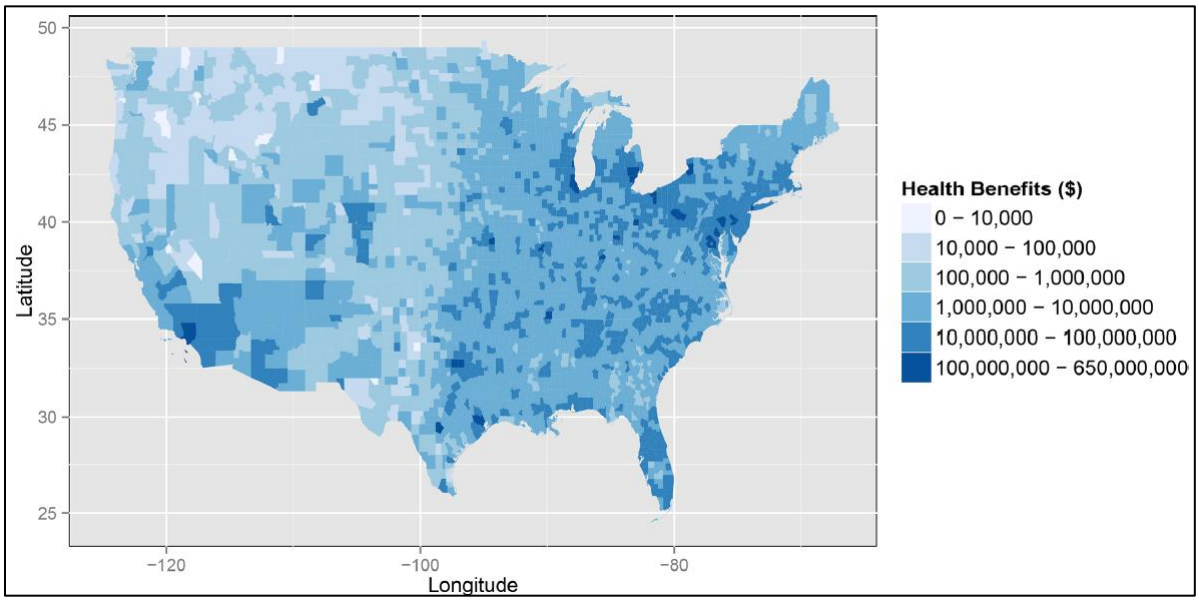
Based on an analysis of three national-level climate mitigation policies (for the electric sector, transportation sector, and an economy-wide trading system, respectively), a 2014 study by concluded that the health benefits associated with reduced $PM_{2.5}$ and ozone could offset some or all of the near-term costs of these policies (Thompson et al. 2014). Estimated public health benefits offset costs of mitigation by a range of 26 to 1,000 percent, with the economy-wide trading system offering the greatest flexibility and the largest potential net-benefits to health. Emission reductions occurring through a clean energy standard generated a median of nearly $40 billion in net benefits, accounting for nearly 120 percent of costs.

A 2015 study compared three national-level climate policies to determine which policy achieved the largest public health co-benefits, based on estimated changes in $PM_{2.5}$ and ozone (Driscoll et al., 2015). The authors found that limiting carbon emissions from power plants, while providing flexible compliance mechanisms and emphasizing energy efficiency investments, resulted in greater health co-benefits than a carbon tax of requiring heat-rate improvements at coal-fired plants. The energy efficiency investment scenario resulted in an estimated 3,500 premature deaths avoided nationally (with a range of 780 to 6,100) through changes in $PM_{2.5}$ and ozone. The study found that air quality improvements are maximized by shifting electric generation from coal plants to lower-carbon emitting sources and investing in demand-side efficiency measures.

A more recent study of a moderately stringent, highly flexible national policy scenario modeled after the final Clean Power Plan (EPA's proposed rule for power plants' GHG emissions nationally) estimates that public health benefits will exceed implementation costs by $12 billion per year in 2020 (Buonocore et al. 2016). The value of health benefits in RGGI states ranged from $10,000 to $100 million per county (see Figure 3). Under this scenario, the study estimates a total of $880 million in public health benefits in the New England states. Among New Jersey, Delaware, Maryland, and Virginia (a non-RGGI state[16]), the study estimates a total of $3 billion in public health benefits. For New York alone, the study estimates a total of $1.6 billion in health benefits.

[16] Throughout this report, we use the term "non-RGGI" to refer to states in the Northeast U.S. that are not participating in the RGGI program.

Figure 3. Total Annual Health Benefits in 2020 by County for Moderately Stringent, Highly Flexible Carbon Standards



Source: Buonocore et al. (2016).

Notably, the authors modeled investments in energy efficiency measures beginning in 2013 and increasing until 2025. Associated benefits from energy efficiency accrue years after initial investments are made; therefore, a comparison of costs in 2020 to benefits in 2020 does not take into account total benefits expected when the modeled regulation reaches its full effect in 2030. The authors conclude that not only are health benefits realized in the near term, they are also expected to extend past 2020 (Buonocore et al. 2016).

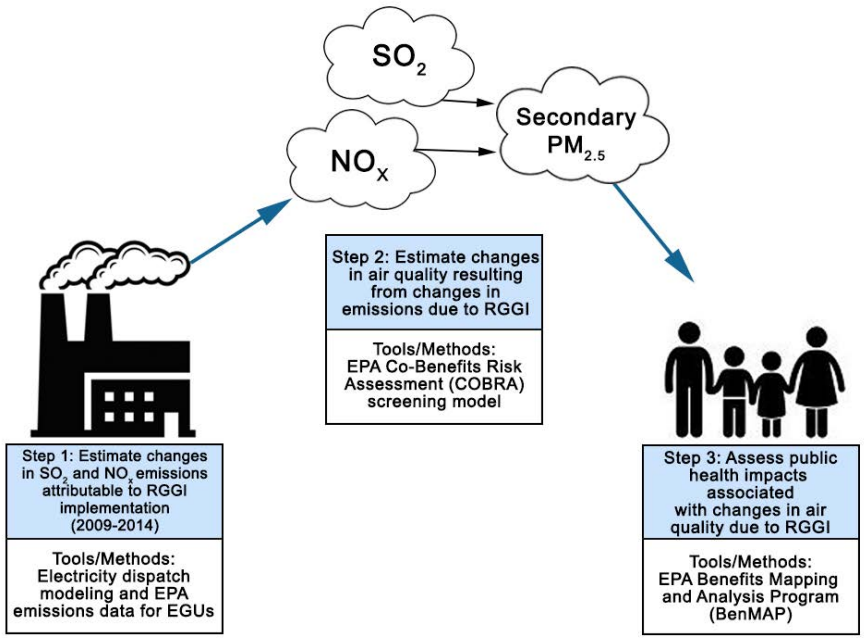
Despite the diversity and complexity of climate and energy scenarios modeled in these studies, they point to a consistent conclusion: there is potential for public health benefits to meet or exceed costs of mitigating GHG emissions by a significant degree. As Thompson et al. (2014) and Buonocore et al. (2016) both observe, estimates of overall net benefits are more sensitive to estimates of mitigation costs than to public health and other benefits.

3. Analytic Approach

We used a three-step analytic process to estimate the impacts on air quality and public health resulting from implementation of the RGGI program from 2009 to 2014. As shown in Figure 4, each of these steps relies upon a specific modeling tool (or tools) and datasets to estimate the incremental impacts of RGGI on the following variables: generation (in megawatt-hours (MWh)) by power plants, air pollution emissions, air quality, and public health.

This analysis was highly sequential—results from each analytic step were inputs to the next modeling tool in this process. At each stage of the analysis, we reviewed draft results at a highly disaggregated level and performed quality control before using results as an input to the next analytic step. In many cases, draft results were benchmarked to results from similar analyses and studies as another cross-check.

Figure 4. Overview of Analytic Steps and Tools



Source: Abt Associates analysis (2017).

Step 1: Estimate annual changes in electric generation and emissions of air pollutants at power plants as a result of RGGI implementation from 2009 to 2014.

To determine annual changes in emissions of air pollutants from electric power plants associated with RGGI implementation, we first estimated changes in electricity generation in participating RGGI states. For this step, we relied upon results from electricity dispatch modeling performed by Analysis Group in support of their studies of RGGI's regional economic impacts. These dispatch modeling runs were used to calculate incremental differences in electricity market outcomes between an "RGGI" scenario, and a counterfactual "No RGGI" scenario. Specifically, the difference in results of these two scenarios is the

incremental change in annual generation levels (in MWh) for power plants located in the RGGI states (including plants not regulated under RGGI).[17]

We then used actual, annual plant-level emissions and pollution control data from EPA to calculate changes in NO_x and SO_2 emissions associated with changes in generation at the power plant level due to RGGI.[18] Changes in plant-level NO_x and SO_2 emissions were aggregated at the county level for each year from 2009 to 2014, and then became the key inputs to the air quality modeling conducted in Step 2.

Step 2: Estimate annual changes in air quality at the county level associated with changes in SO_2 and NO_x emissions from power plants, by year.

For this step in the analysis, we used the COBRA model, developed by EPA to conduct screening-level analyses of the effect of changes in emissions on air quality. We ran COBRA using inputs of annual changes in SO_2 and NO_x emissions aggregated for each county in all RGGI participating states derived under Step 1 of the analysis.

COBRA's air quality model simulates chemical reactions in the atmosphere that transform NO_x and SO_2 into components of particulate matter. In the northeastern United States, these components constitute the majority of $PM_{2.5}$ resultant from power plant emissions and make up more than half of all ambient $PM_{2.5}$ (NARSTO, 2004). As noted earlier, as a simplified air quality model, COBRA does not model formation of ozone, although this is a major pollutant in the Northeast.

COBRA's outputs are changes in annual ambient $PM_{2.5}$ at the county level, which are the inputs to public health modeling conducted under Step 3.

Step 3: Assess public health impacts associated with changes in air quality due to RGGI implementation from 2009 to 2014.

We used the Benefits Mapping and Analysis Program (BenMAP) to translate county-level changes in annual ambient $PM_{2.5}$ from Step 2 into county-level changes in the frequency of various adverse health events among a population, referred to as incidences. BenMAP uses inputs of air quality changes, population, and baseline health incidences (i.e., the background frequency of a health impact in a population) to estimate the public health changes resulting from changes in air quality. BenMAP then estimates the economic value of health incidences avoided based on a synthesis of multiple economic valuation studies.

3.1 Estimating Changes in Emissions due to RGGI

Estimating changes in emissions due to RGGI requires isolating RGGI's incremental effect on the electricity market from that of the many other factors affecting the complex electric power system. Variations in weather and economic growth can influence electricity demand. And before RGGI's

[17] The scope of results from the dispatch modeling runs used in this analysis reflected changes in generation by power plants located in RGGI states, but did not include changes in other states and provinces adjacent to or with interconnection to RGGI. Results from dispatch modeling were also available for Pennsylvania but were not validated for plant additions, retirements, and other changes that occurred during the timeframe of this analysis.

[18] While power plants also emit other pollutants that affect air quality and health (such as mercury and air toxics), these pollutants' effects on air quality are not captured in the air quality modeling tool applied in this analysis.

inception in January 2009, major transformations in the market for natural gas, which is a key fuel used in electricity production, were underway. Advancements in shale gas extraction methods significantly increased the supply of domestic natural gas and resulted in substantial decreases in natural gas prices beginning in 2008.[19] Also in this timeframe, effects of the 2009 recession dampened demand for electricity.

In 2010, RGGI Inc. commissioned a study[20] to examine the role of factors that contributed to a 33 percent decrease in CO_2 emissions from the electric power sector across RGGI states, from 2005 to 2009 (RGGI Inc., 2010).[21] As shown in Figure 5, the study found that fuel-switching from oil and coal to lower-cost natural gas accounted for nearly one-third of the decline in CO_2 emissions from 2005 to 2009. An additional 25 percent of emissions reductions were due to weather, whereas the economic recession was responsible for a small fraction (about 4 percent) of emission reductions. Changes in available generation capacity (i.e., reduced coal capacity and increased nuclear, wind, and hydropower capacity) together accounted for nearly 21 percent of the reduction in emissions.

Finally, energy efficiency and customer-sited renewable generation accounted for approximately 12 percent of emissions reductions over this timeframe. While the study was not an analysis of the effect of the RGGI program, it showed that fuel-switching to natural gas and weather variations were more significant factors in the rapid decline of CO_2 emissions over the 2005 to 2009 timeframe than economic conditions or changes in the mix of available generation capacity.

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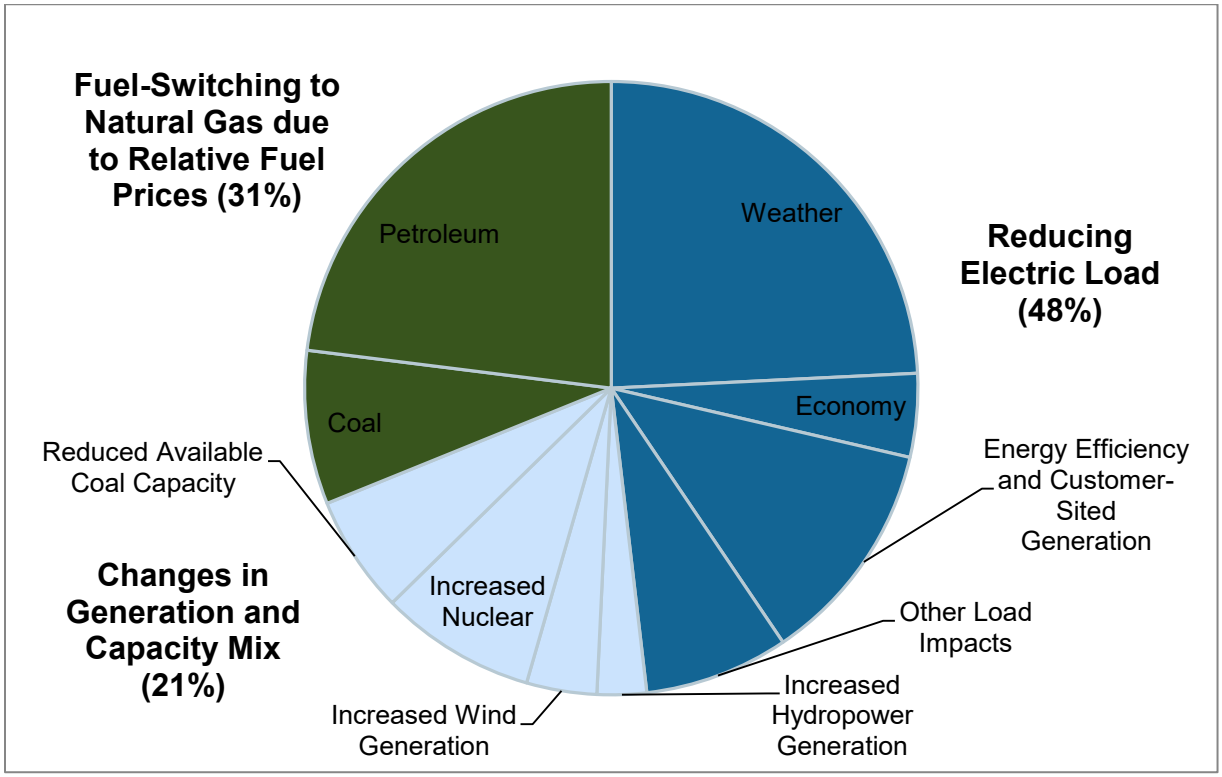
[19] The Henry Hub price for natural gas fell by nearly 70 percent between 2008 and 2015 (EIA, 2016).

[20] This study was conducted for RGGI Inc. in 2010 by the New York State Energy Research and Development Authority.

[21] Note that the timeframe of the RGGI Inc. study preceded RGGI program implementation and was focused on changes in emissions that pre-dated RGGI.

Figure 5. Factors Influencing CO_2 Emission Reductions in RGGI States, 2005-2009



Source: RGGI Inc. (2010).

Note: Connecticut, Delaware, Maryland, Massachusetts, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont are included in this analysis.

A more recent study focused specifically on RGGI's role in reducing regional CO_2 emissions during the first compliance period (2009 to 2011) (Murray and Maniloff 2015). Using econometric modeling, the study isolated the incremental effect of RGGI on emissions from that of other factors, including lower natural gas prices, the 2009 economic recession, and other environmental and energy programs, including states' minimum requirements for renewable energy generation (known as Renewable Portfolio Standards). Accounting for these factors, the study found that CO_2 emissions would have been 24 percent higher in the region over the first compliance period if the RGGI program did not exist (Murray and Maniloff 2015).[22]

[22] The study compared changes in CO_2 emissions from the electric sector from 1990-2008 to the 2009-2012 period and found that without low natural gas prices, the RGGI program, the recession, or state renewable goals, CO_2 emissions would have been 52 percent higher across the region. The same counterfactual scenario applied nationally found total CO_2 emissions would have only been 11 percent higher from 2009 to 2012. As such, the study concluded that nearly half of the actual CO_2 emissions reductions in RGGI states during this time period can be attributed to RGGI program implementation. The Murray and Maniloff study did not distinguish between the impact of RGGI's CO_2 allowance price from the effects of RGGI states' investments in energy efficiency and renewable energy on emissions, but noted that both are key aspects of RGGI's effect on generation and emissions.

For this analysis, we relied upon results from dispatch modeling of RGGI's first two compliance periods conducted by Analysis Group. These modeling runs estimated RGGI's incremental effect on overall electricity demand, the mix of generation sources and dispatch from power plants in the RGGI states, independent of changes in other variables over the 2009 to 2014 timeframe. These modeling runs provide an estimate of RGGI's incremental effect on the electricity market by simulating a "RGGI" scenario and a "No RGGI" counterfactual scenario. Modeling of the RGGI scenario depicted the two primary direct effects of the program on the wholesale power market, as described below:

- **Costs of CO_2 allowance purchases:** Owners of large fossil-fuel power plants purchase CO_2 allowances to meet RGGI's cap on emissions, and then build the costs of these purchases into the price at which they are willing to supply power to the wholesale market.[23] In this way, the cost of CO_2 allowances affects prices for power in many hours, which in turn can alter marginal generation (i.e., the last generator dispatched to meet hourly demand) from higher- to lower-carbon generation sources.
- **Investments of RGGI proceeds into energy efficiency (EE) and additional renewable generation (RE):** States' investments of RGGI proceeds into energy efficiency measures result in reductions in overall electricity demand and changes in the shape of annual electricity demand profiles.[24] Although much smaller than states' investments in energy efficiency, investments of RGGI proceeds in customer-sited renewables increase the capacity for low- or zero-carbon electricity. Demand-side efficiency investments and an increase in renewable capacity together shift demand for fossil-based electricity downward, resulting in changes to the mix of generation sources dispatched and associated emissions.

The No RGGI scenario is a counterfactual case of power market outcomes absent these two effects of RGGI. In this counterfactual scenario, all other variables affecting power markets except for RGGI (i.e., fuel prices, transmission constraints, NO_x and SO_2 allowance prices, state renewable energy requirements, plant retirements and additions) were held constant to the RGGI scenario. The difference between these two scenarios (i.e., RGGI and No RGGI) represents RGGI's incremental effect on the power system; specifically, changes in hourly generation by power plants located in RGGI states.

Because this analysis is retrospective, we had access to actual historical data depicting annual generation and emissions at individual power plants under RGGI. However, our retrospective approach also presented some analytical challenges in cases where results for the modeled RGGI scenario differ from

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[23] New England and many mid-Atlantic states have competitive markets for electric power, which means that prices bid into the market by power plant owners should be close to the marginal costs of producing the last unit needed to meet hourly electricity demand.

[24] Different energy efficiency programs tend to reduce hourly electricity demand in different ways, and thus affect the "shape" of customer demand over the course of the year in addition to reducing the total aggregate demand across the year. For example, energy efficiency programs that focus on replacing older, inefficient air conditioning units with newer, more efficient models generate reductions in electricity demand almost exclusively in summer daytime hours, when electricity demand peaks across the Northeast region. An air conditioning energy efficiency program thus alters the "shape" of electricity demand by generating reductions only in summer daytime hours. This, in turn, disproportionately reduces generation from the most expensive, least efficient, and most polluting generating resources during the highest-load hours of the year.

actual RGGI data. Such differences are typical because dispatch models simulate economically optimized outcomes that do not perfectly align with power producers' actual, real-world decisions.

To calibrate dispatch modeling results to actual, "real-world" outcomes, we based our analysis on the *relative* incremental effect of RGGI simulated by the dispatch modeling. Using actual data for RGGI, we constructed a new No RGGI scenario by applying the *percent difference* between emissions levels from the modeled results for the RGGI and No RGGI scenarios to actual emissions levels under RGGI. The difference between the RGGI emissions inventory and the No RGGI emissions estimate is the incremental change in emissions due to RGGI. These emissions changes then become the inputs to Step 2 of the analysis described below.

Appendix A includes descriptions of specific calculations and datasets used in our analysis of incremental emissions changes due to RGGI.

3.2 Air Quality Modeling

EPA developed the COBRA model to conduct screening-level analyses of the effect of emissions changes on air quality. COBRA models the ambient air quality changes that result from criteria pollutant emissions using a simplified air dispersion model, which quantifies the relationships between emissions from each source and air quality (average annual $PM_{2.5}$) in each county. As described earlier, the choice to apply the COBRA air quality modeling tool for this analysis results in a somewhat more limited picture of actual changes in air quality than could be developed with a more detailed air quality modeling tool.[25] To reiterate, COBRA estimates how changes in emissions of primary $PM_{2.5}$, SO_2, and NO_x result in changes in ambient levels of $PM_{2.5}$, but COBRA does not model changes in ozone formation.

We used the COBRA model in order to estimate changes in air quality due to RGGI implementation. To run the COBRA model, we input estimated annual changes in SO_2 and NO_x emissions derived under Step 1 of the analysis, aggregated at the county level, for all counties in RGGI participating states. We input these into COBRA for each modeling year 2009 through 2014 and then performed a COBRA run for each of these years. Outputs from each of these COBRA runs are changes in annual levels of ambient $PM_{2.5}$ for each county, and are expressed in micrograms per cubic meter ($\mu g/m^3$). Annual county-level changes in ambient $PM_{2.5}$ then became the inputs to Step 3, modeling of public health impacts.

The scope of our analysis of air quality excludes the effect of energy savings associated with RGGI states' investments in energy efficiency made in the 2009 to 2014 timeframe that persist past 2014. To include the effect of these energy savings on air quality and health would require a projection of emissions inventories for all sectors to support additional COBRA modeling runs for each year subsequent to 2014. Because projections for future baseline emissions are currently unavailable for this timeframe, however, the impact of these energy savings was excluded from this analysis.[26]

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[25] For example, the Community Multiscale Air Quality and CAMx models are often used to conduct cost-benefit studies of major proposed regulations—these models are capable of very detailed atmospheric modeling to estimate how emissions form ambient levels of ozone and ambient fine particles at very granular geographic levels.

[26] Specifically, the only annual emissions projection currently available from EPA is for the year 2025.

COBRA and underlying assumptions and data sources used for this step are described in more detail in Appendix B.

3.3 Public Health Modeling

To estimate the public health benefits resulting from RGGI, we used EPA's BenMAP, Version 4.0.67.[27] BenMAP uses data describing population, frequency of baseline health outcomes, and economic values to estimate the number and economic value of health impacts resulting from changes in air quality.

Abt Associates designed and implemented the original BenMAP model for EPA, which was the first publicly available model for valuing the health impacts of changes in air quality. EPA's current version of BenMAP[28] is being deployed around the world by government agencies and others for generating estimates of public health improvements resulting from reductions in air pollutants.

We used the county-level estimates of RGGI's effect on $PM_{2.5}$ relative to observed ambient $PM_{2.5}$, generated by COBRA under Step 2, as inputs to BenMAP. BenMAP used these estimated changes in ambient $PM_{2.5}$ to calculate the health benefits resulting from RGGI for 2009-2014.

BenMAP and underlying assumptions and data sources used for this step are described in more detail in Appendix C.

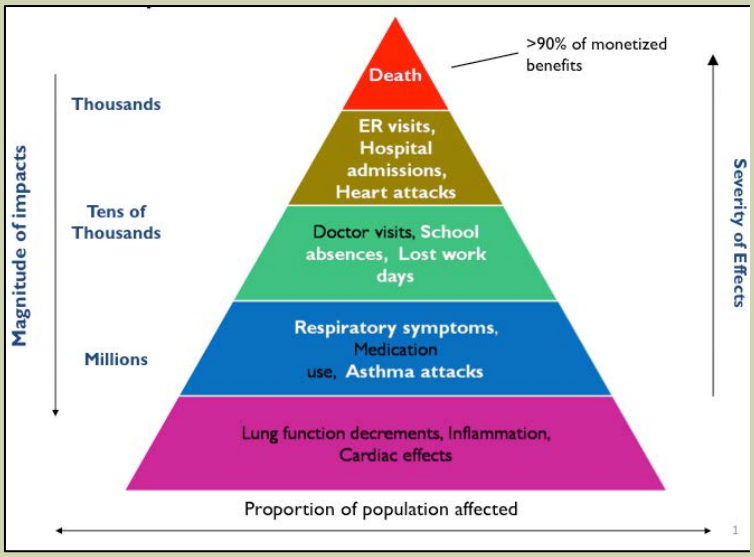
[27] COBRA also has functionality to estimate health benefits, but we selected BenMAP over COBRA for this step of the analysis because BenMAP allows us to capture changes in baseline population, incidence, and valuation over the entire study timeframe. While COBRA is an appropriate tool for estimating ambient air quality, the fact that its datasets are tied to a specific calendar year limits its representation of how air quality affects public health over time.

[28] This version is known as BenMAP-Community Edition.

How Does BenMAP Value Health Benefits?

As a society we value a clean, safe environment and a healthy population. Without an explicit value tied to a public good such as clean air,[1] it is challenging to evaluate the costs, benefits, and overall effectiveness of policies and programs that enhance or protect public goods. To estimate the value of public goods that are not traded in markets, economists rely upon a range of methods. One approach to quantifying the value of programs that benefit human health is to calculate the value of avoiding the "cost of illness," such as medical expenses and lost productivity. Another method is based on the value that individuals are willing to pay to avoid illness or reduce the risk of premature death.

Effects of Air Pollution on Health



Source: U.S. EPA (2016a).

To estimate a value for health benefits resulting from a reduction in air pollution, BenMAP estimates the value of total avoided health costs. BenMAP links air quality changes to public health outcomes by applying empirical relationships derived from epidemiological studies between air pollutants and 12 categories of human health effects (described in detail in U.S. EPA, 2015a). The economic value of improving air quality increases with the number of avoided premature deaths and illnesses, though the value of different avoided health effects can vary widely. For example, the economic, or "monetized" value for an avoided case of adult mortality is over $9 million, compared to the monetized value of an avoided case of respiratory symptoms ($22-$36); see Appendix C for a table of avoided health effects and their economic values.

As the "pyramid of effects" in the accompanying figure illustrates, the majority of monetized health benefits from reductions in air pollutants arise from a small number of avoided premature deaths (U.S. EPA, 2016a). The value of an avoided premature death is an estimate of how much people are willing to pay for small reductions in the risks of premature death (U.S. EPA, 2016b). This concept of avoided risk is commonly expressed as the "value per statistical life" (VSL), and is a commonly used value in economic and regulatory analysis of environmental and public health policies. It is important to note that the VSL concept represents the sum of many small risk reductions that are then aggregated, and does not represent the monetary value of an individual life.

4. Results and Discussion

In this section of the report, we discuss results from each analytic step used to determine RGGI's impact on public health. We then provide an overview of key findings, policy implications, and uncertainties for these results.

4.1 Changes in Generation due to RGGI

We calculated changes in electricity generation due to RGGI first on an absolute basis (in MWh per year), and then expressed them as a percentage relative to generation that would have occurred in the No RGGI scenario. These percentages are based on generation changes in RGGI-participating states only. Table 4 shows that the RGGI program resulted in a net reduction in electricity generation in every year of the first two compliance periods.[29]

Table 4. Annual Change in Generation due to RGGI

	2009	2010	2011	2012	2013	2014
Generation change in RGGI States	-5.8%	-2.9%	-2.0%	-3.4%	-7.0%	-6.9%

Source: Abt Associates analysis (2017).

Reductions in annual generation ranged from a low of 2.0 percent in 2011 to a high of 7.0 percent in 2013. Changes in generation as a result of RGGI were lowest overall in 2010 and 2011. The most significant RGGI-induced changes in generation occurred in 2009, 2013, and 2014.

In competitive electricity markets, changes in any number of variables, including fuel prices, weather, and plant and system operational changes, can cause variations in the level of electricity dispatched by a given power plant (or group of plants) from year to year. In this analysis, however, our modeling results account for all of these factors and thereby isolate the incremental effect of RGGI on electricity markets and dispatch. Thus, we interpret RGGI-induced changes in generation to be a result of the combination of (1) RGGI states' investments in energy efficiency and renewable energy and (2) the effect of CO_2 allowance prices on electricity dispatch. Our analysis does not quantify the individual contributions of these elements of the RGGI program to RGGI's overall net effect.

In addition to allowance prices and states' investments in EE and RE, the "announcement effect" is another factor that may have influenced the market response to RGGI. This effect describes the response by power plants owners to RGGI states' announcements of their intentions to join the RGGI system. If a plant owner believes an announcement to be credible, the prospect of future carbon prices can spur them to invest in lower-carbon generation options before the policy starts.[30] A 2015 study found that the

[29] Note that this analysis reflects modeling results only for those states that participated in RGGI at some point during the first two compliance periods. New Jersey participated in RGGI's first compliance period from 2009 to 2011, but did not participate in RGGI's second compliance period from 2012 to 2014. We modeled generation changes in New Jersey for 2009 to 2011, and assumed no generation changes from 2012 to 2014.

[30] Alternatively, if firm or plant owners do not view a policy announcement as credible, they might wait until a program takes effect to act. Murray and Maniloff (2015) noted literature which finds that the announcement effect was significant for policies addressing other air pollutants.

announcement of the RGGI program likely had a statistically significant effect on CO_2 emissions before and shortly after RGGI's start date (i.e., late 2008 and early 2009)—this suggests that owners of power plants in RGGI states did find states' policy announcements to be credible and took early actions to reduce CO_2 emissions (Murray and Maniloff 2015). The anticipation of pending CO_2 emissions limits may have affected plant owners' demand for CO_2 allowances and generation bids in 2009, the first year of the program.

Note that these results do not reflect changes in generation that may have occurred at power plants located in states or Canadian provinces (e.g., Quebec) adjacent (and with interconnection) to RGGI states, but not participating in RGGI. It is possible that changes in the marginal costs of electricity dispatch associated with pass-through of the cost of CO_2 allowance purchases by plant owners in RGGI states resulted in increases in electricity dispatch in non-RGGI states and provinces outside RGGI to some degree. Modeling by Resources for the Future (RFF) in 2004 projected that under RGGI, generation and CO_2 emissions in non-RGGI states would increase due to RGGI. Specifically, RFF estimated that that for every 100 tons of CO_2 reductions within the RGGI region, non-RGGI states and provinces adjacent to the RGGI region could emit an additional 37 tons of CO_2, a dynamic known as "leakage" (RFF, 2004).

RGGI Inc. (2013) examined patterns in generation in neighboring states over the first three years of RGGI implementation, and did not find conclusive evidence of substantial leakage to generators in non-RGGI states:[31] CO_2 emissions from non-RGGI electricity generators did not appreciably increase during 2009 to 2011 relative to a base period of 2006 to 2008, and total electric generation from all non-RGGI electric generation sources serving load in the RGGI region increased by only 1.2 percent, or 3.3 million MWh, over the same timeframe. A later RGGI Inc. study (2016) found that generation from all generators in non-RGGI states increased by nearly 12 percent in 2012 to 2014 compared to the 2006 to 2008 base period. However, neither RGGI Inc. study estimated RGGI's incremental effect on changes in generation in non-RGGI states and provinces relative to a counterfactual scenario, and thus are inconclusive with respect to the program's incremental impact on CO_2 emissions from these jurisdictions.

To account for the uncertainty in RGGI's effect on generation and emissions from fossil-fuel generators located in neighboring non-RGGI states and provinces, we applied a sensitivity factor that discounts benefits in non-RGGI states by 50 percent to represent a low-end estimate. Our high-end estimate of our range of estimates assumes 100 percent of benefits for non-RGGI states were realized.

4.2 Changes in Criteria Pollutant Emissions due to RGGI

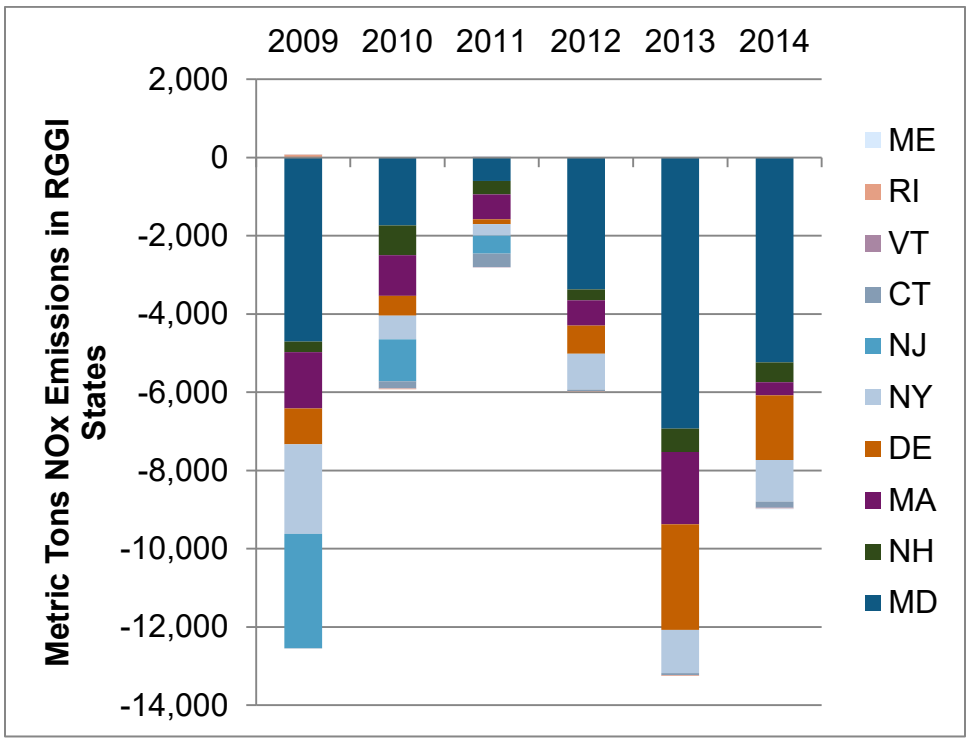
As described earlier, this analysis tracks changes in emissions of SO_2 and NO_x resulting from RGGI implementation. Annual changes in levels of these pollutants are the primary inputs to modeling of RGGI's impacts on air quality and public health.

Results of this analysis show that RGGI resulted in net reductions of both pollutants in each year of RGGI's first two compliance periods. Figure 6 shows that the largest reductions in NO_x emissions due to

[31] Note that RGGI Inc.'s monitoring reports are based only on comparisons of empirical data for generation and CO_2 emissions since RGGI's start in 2009 to similar data before the program began, and do not include modeling of a counterfactual No RGGI scenario. As such, RGGI Inc. notes that it cannot say conclusively what the likely magnitude of changes in generation and CO_2 emissions from neighboring non-RGGI states would have been in the absence of the RGGI program.

RGGI also coincide with years with the most significant declines in generation—2009, 2013, and 2014. In 2009, NO_x reductions from Maryland plants accounted for about one-third of total reductions, with plants in New York and New Jersey also accounting for significant NO_x reductions. In 2013 and 2014, reductions from plants located in Maryland and Delaware accounted for most of the reductions in total NO_x emissions. Decreases in NO_x emissions due to RGGI were at their lowest levels in 2010, 2011, and 2012.

Figure 6. Changes in NO_x Emissions due to RGGI

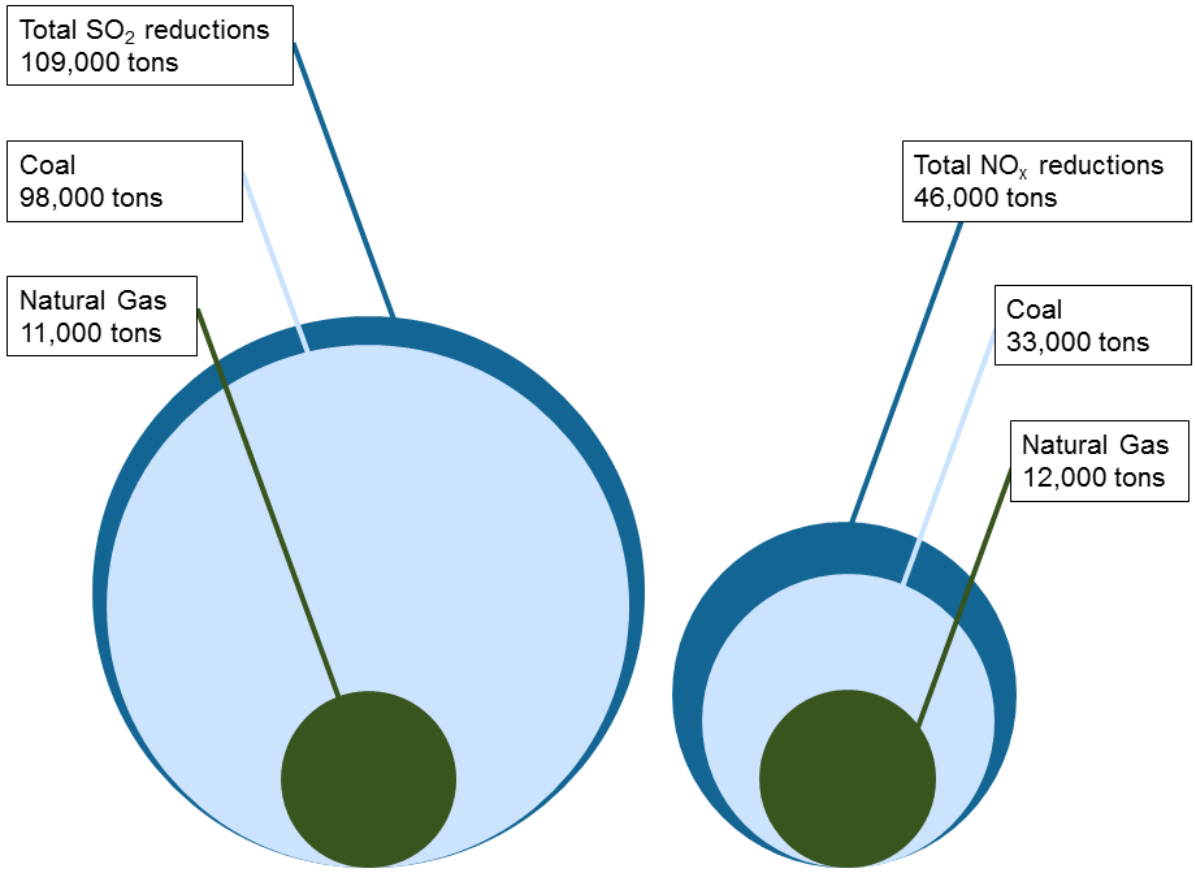


Source: Abt Associates analysis (2017).

Due to the high sulfur content of coal, emission rates of SO_2 are significantly higher for coal-fired power plants than for natural gas plants. Therefore, reductions in generation by coal-fired plants as a result of RGGI dominate total SO_2 reductions. As shown in Figure 7, coal plants account for 90 percent of reductions in SO_2 emissions resulting from RGGI. However, NO_x emission rates for coal- and natural-gas fired generation are much more comparable, especially when coal units are controlled for NO_x.[32] As such, RGGI-induced reductions in NO_x emissions can occur from a decline in generation by either coal-fired or natural gas-fired units. As shown in Figure 7, coal plants account for 73 percent of total RGGI-induced NO_x reductions from 2009 to 2014, while natural gas plants account for 26 percent of total NO_x reductions due to RGGI in the same timeframe.

[32] See Figure 18 in Appendix D for a comparison of NO_x and SO_2 emission rates across generation technologies and fuel types.

Figure 7. Changes in SO_2 and NO_x Emissions due to RGGI from 2009-2014, by Fuel Type

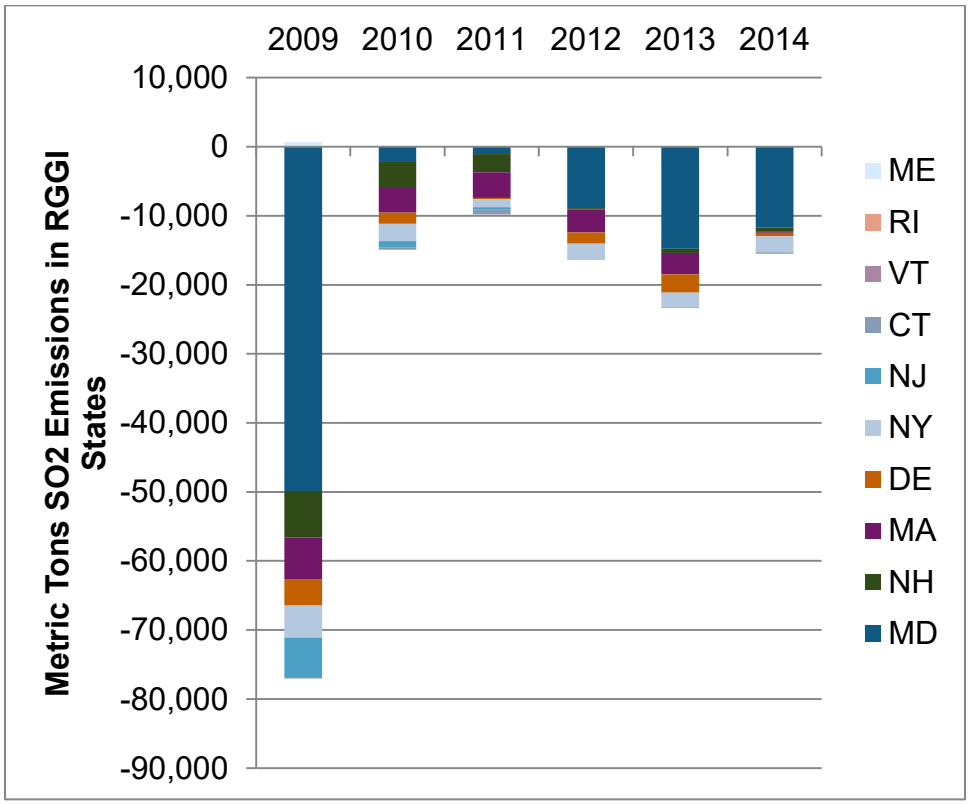


Source: Abt Associates analysis (2017).

Figure 8 shows that RGGI results in a decline in SO_2 emissions relative to the No RGGI baseline in every year of RGGI's first two compliance periods. RGGI had by far the greatest impact on SO_2 emissions in 2009, when SO_2 emissions fell by more than 76,000 metric tons. This single-year decline also accounts for nearly half of total reductions in SO_2 emission reductions over the full 2009 to 2014 timeframe. Moreover, the majority of SO_2 emission reductions in 2009 occurred in Maryland, which has the largest capacity of coal-fired power plants in all RGGI states. In response to Maryland's Healthy Air Act of 2006, SO_2 controls were installed at five of Maryland's coal plants in late 2009.[33] As a result of these controls, the SO_2 emissions rate (tons of SO_2 per MWh) declined by nearly an order of magnitude at some of these plants. This explains why absolute SO_2 reductions in Maryland are much smaller for all years after 2009, even in years such as 2013 and 2014 when RGGI resulted in meaningful decreases in generation from these plants.

[33] Controls for SO_2 were installed in the last two months of 2009 on the following Maryland coal plants (units): Brandon Shores (1 unit); AES Warrior Run (1 unit); Morgantown (2 units); Dickerson (3 units); and Chalk Point (2 units).

Figure 8. Changes in SO_2 Emissions due to RGGI



Source: Abt Associates analysis (2017).

Accounting for State Power Plant Regulations: Maryland's Healthy Air Act

With seven large power plants and more than 4,600 MW of capacity fired by coal, at the time of RGGI's start in 2009, Maryland had the largest inventory of criteria pollutant emissions from power plants of all states in the RGGI region. In 2006, Maryland passed the Healthy Air Act (HAA) in 2006 to achieve Clean Air Act goals for NO_x, SO_2, and Hg emissions from large power plants. Owners of Maryland coal-fired power plants installed a significant number of controls for these pollutants shortly after HAA took effect. Most of these controls, which included flue gas desulfurizers, baghouses, injection systems, and scrubbers, were installed on MD coal units within four years after HAA took effect. These controls were highly effective—between 2009 and 2010, SO_2 emissions fell by more than 80 percent, and NO_x emissions declined by more than 60 percent from 2007 to 2009 (Maryland Department of the Environment, 2015).

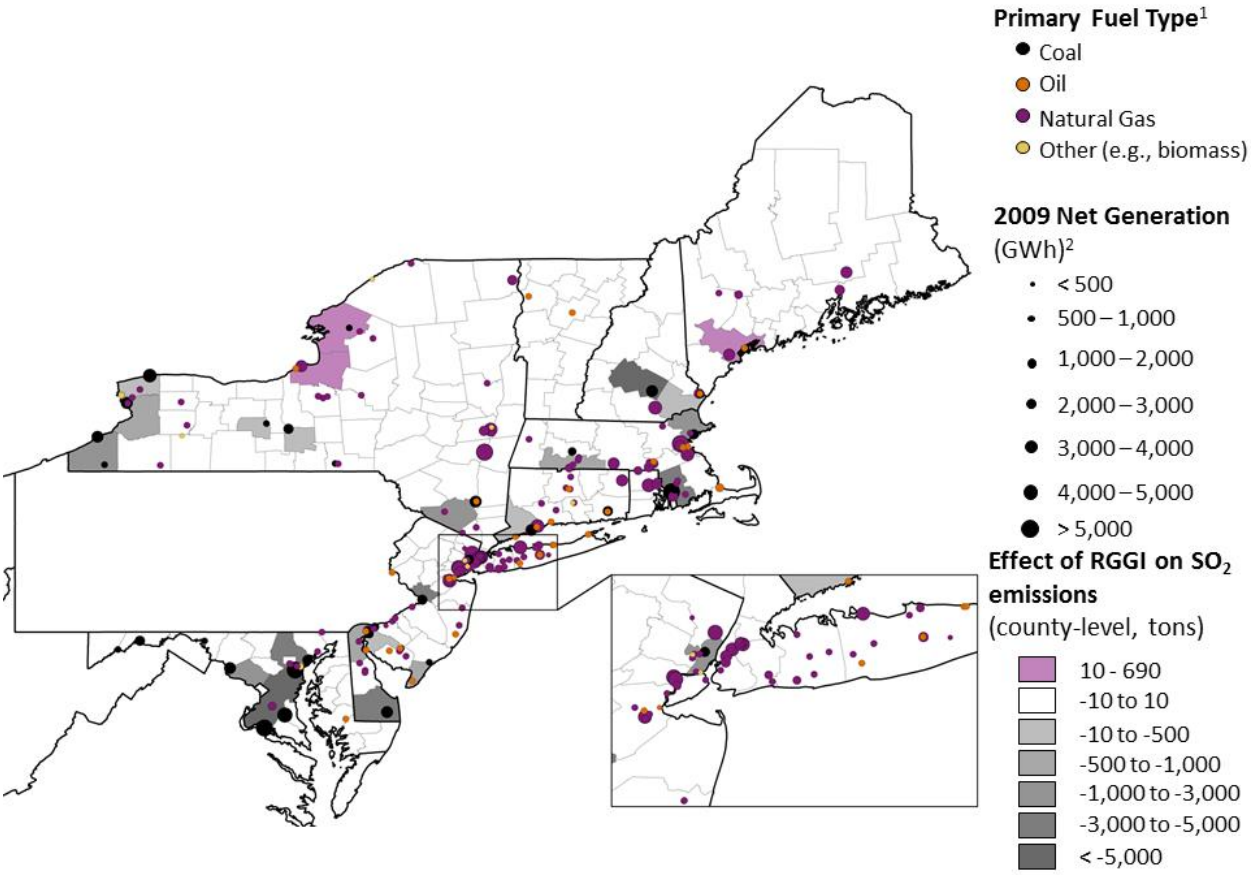
Given the importance of SO_2 emissions from Maryland's coal-fired power plants to this analysis, we sought additional input from Maryland Department of Environment staff to make sure that our emissions inventories for 2009 and 2010 accurately reflected total emissions for Maryland's power plants. We also pulled plant-specific data on control installations from EPA to ensure that our plant-specific emission factors for SO_2 and NO_x reflected changes made in response to the HAA. As a result, we are confident that results from this analysis reflect incremental emissions reductions in Maryland that are attributed to RGGI rather than to Maryland's HAA. We also confirmed that annual emission factors for other coal plants outside Maryland accounted for installations of pollution controls.

In addition to reductions from Maryland, RGGI has also resulted in SO_2 reductions from individual legacy coal plants[34] located in Delaware, New England, and New York, as shown in Figure 9. However, because these coal plants are generally more geographically isolated than Maryland's coal plants,[35] the impacts of SO_2 emissions reductions from these individual plants on air quality in surrounding downwind counties is more easily observable in air quality results. For the most part, the single largest county-level reductions in SO_2 emissions in 2009 occurred in or immediately adjacent to a county with a large coal-fired plant; however, a few oil-fired plants also played a role in changes in SO_2 emissions. In a few counties, SO_2 emissions actually increased to a small degree due to an increase in generation by a local oil- or coal-fired plant. However, each of these counties still experienced net improvements in air quality.

[34] Legacy in this context refers to older coal plants, built in the 1950s to 1970s to serve baseload power needs and whose original capital costs are fully amortized.

[35] Five of Maryland's coal plants are clustered relatively close together in Anne Arundel, Charles, and Prince Georges counties.

Figure 9. RGGI-Regulated Plants and 2009 SO_2 Reductions



Source: Abt Associates analysis (2017).

1. Primary fuel type identified from the Emissions and Generation Resource Integrated Database (eGRID) (U.S. EPA 2009).

2. Net generation data from the EIA Form 923 (U.S. EIA, 2009b). Net generation includes generation from all fuel types, not just the primary fuel type. Excludes generation from nuclear units.

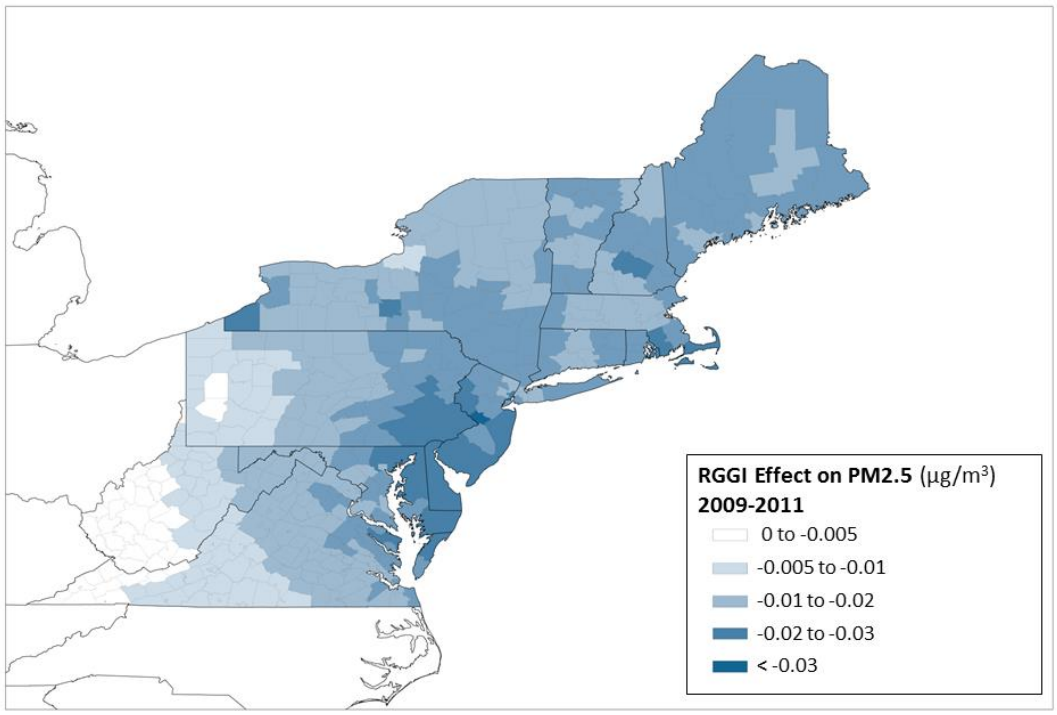
4.3 Impacts on Air Quality due to RGGI

RGGI resulted in incremental improvements to air quality in every year of the program's first six years. However, because air pollutants can be transported long distances from where they are first emitted, the spatial distribution of air quality improvements resulting from RGGI differs from the locations of plants where emission reductions originated.

Figure 10 and Figure 11 illustrate the spatial distribution of county-level changes in air quality due to RGGI for the first and second compliance periods, respectively. Generally, the most significant air quality improvements occurred in states and counties adjacent to or downwind of Maryland's power plants regulated under RGGI, although certain counties in New York (i.e., Chautauqua County and Tompkins County), and New England (Merrimack County, NH and Bristol County, MA) with or downwind of large coal plants also experienced notable air quality improvements due to RGGI. Counties in Delaware

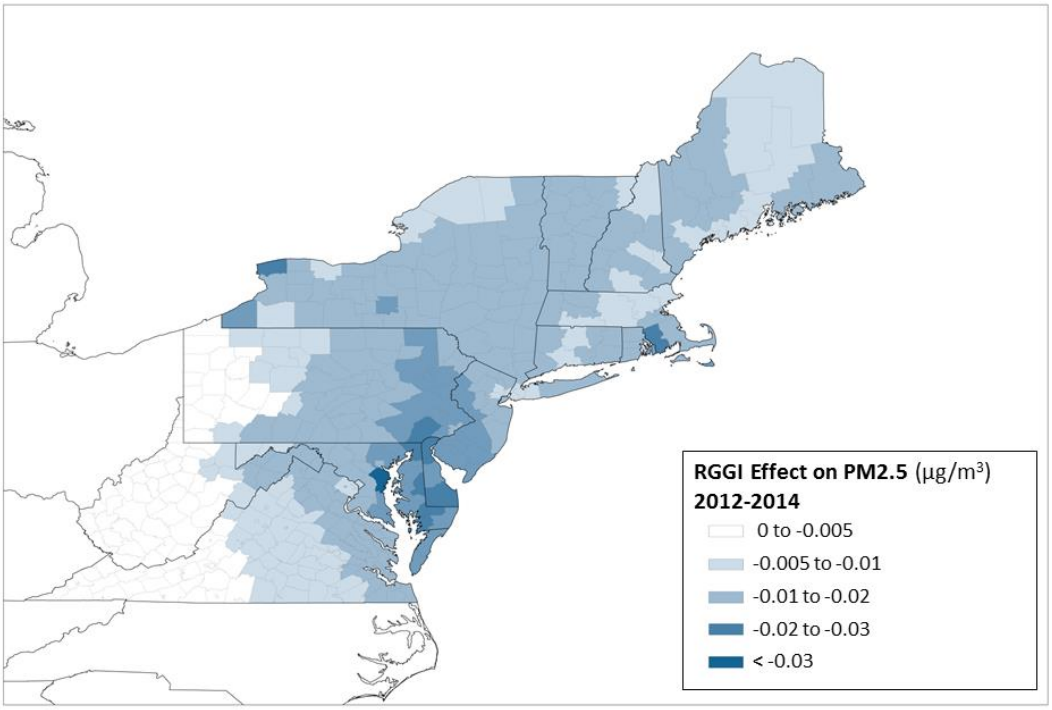
experienced the largest absolute declines in ambient $PM_{2.5}$ under RGGI because of their location immediately downwind of Maryland's coal plants, which account for the largest absolute reductions in SO_2 emissions as a result of RGGI.

Figure 10. RGGI Effect on Annual Average $PM_{2.5}$, 2009 to 2011



Source: Abt Associates analysis (2017).

Figure 11. RGGI Effect on Annual Average $PM_{2.5}$, 2012 to 2014



Source: Abt Associates analysis (2017).

Regional transport of pollution means that changes in emissions from plants located in RGGI states also impact air quality in non-RGGI states. Our modeling results show substantial air quality benefits in the non-RGGI states of Pennsylvania and New Jersey[36] due to emission reductions from plants located in RGGI states. However, as noted earlier, this analysis did not estimate possible shifts in generation and emissions that may have occurred in non-RGGI states in response to RGGI, so these changes cannot be considered net of those changes in emissions and air quality.

All counties in RGGI states met EPA's annual average $PM_{2.5}$ standard during the 2009 to 2014 timeframe and still met this standard when we modeled air quality without RGGI. EPA, however, does not set NAAQS at "zero-risk" levels,[37] which means that incremental benefits to health occur even when air quality improvements exceed EPA standards.

It is important to note that our analysis only addressed changes in annual average $PM_{2.5}$ concentrations, and that $PM_{2.5}$ concentrations are highly variable over the course of a year. A single short-term exposure to high $PM_{2.5}$ concentrations can lead to more severe human health outcomes than multiple exposures to low $PM_{2.5}$ concentrations, which is why EPA sets a 24-hour $PM_{2.5}$ standard as well as an annual average $PM_{2.5}$ standard. To the degree that RGGI states' investments in energy efficiency programs aimed

[36] Note that New Jersey was a participant in the RGGI program in the first compliance program (2009 to 2011) but not in the second (2012 to 2014).

[37] The Clean Air Act does not require EPA to establish air quality standards at a zero-risk level or at background concentrations, but rather at a level that reduces risk sufficiently to be protective of public health "…with an adequate margin of safety." (U.S. EPA, 2010).

specifically at reducing peak load, it is possible that RGGI had an amplified impact on low air quality days. However, the scope of this analysis did not include RGGI's effects on daily air quality changes.

Table 5 and Table 6 show RGGI's effect on air quality, as measured by changes in annual average levels of ambient $PM_{2.5}$, in RGGI states and non-RGGI states, respectively. RGGI's effect on air quality over time was largely consistent with its effect on emissions over time. Changes in air quality due to reductions in average $PM_{2.5}$ levels were the most significant in every state in 2009, and by a fairly significant margin over air quality improvements in other years. The next largest impact on average annual $PM_{2.5}$ occurred in 2012 to 2014, and RGGI's effect on average annual $PM_{2.5}$ was lowest in 2010 and 2011. Overall, air quality improvements in RGGI's first compliance period were larger than those in the second compliance period.

Delaware, Maryland, Pennsylvania, and New Jersey experienced the largest changes in $PM_{2.5}$ in 2009, and Delaware experienced the highest average reduction in annual $PM_{2.5}$ among all RGGI and non-RGGI states over the full time period. Pennsylvania experienced the largest average improvement among non-RGGI states. Improvements in air quality were the lowest in all states in 2011.

Table 5. RGGI Effect on Annual Average $PM_{2.5}$ in RGGI States

State	RGGI Effect on Annual Average $PM_{2.5}$ in RGGI States (Counties weighted by population)						
	2009	2010	2011	2012	2013	2014	Average
DE	-0.12	-0.02	-0.01	-0.03	-0.05	-0.03	-0.04
MD	-0.06	-0.01	0.00	-0.02	-0.03	-0.02	-0.02
RI	-0.05	-0.02	-0.01	-0.02	-0.02	-0.01	-0.02
MA	-0.04	-0.02	-0.01	-0.02	-0.02	-0.01	-0.02
NH	-0.05	-0.02	-0.01	-0.01	-0.01	-0.01	-0.02
VT	-0.04	-0.01	-0.01	-0.01	-0.02	-0.01	-0.02
ME	-0.04	-0.01	-0.01	-0.01	-0.01	-0.01	-0.02
CT	-0.04	-0.01	-0.01	-0.01	-0.01	-0.01	-0.02
NY	-0.04	-0.01	0.00	-0.01	-0.01	-0.01	-0.01
NJ	-0.08	-0.01	0.00				

Source: Abt Associates analysis (2017).

Table 6. RGGI Effect on Annual Average $PM_{2.5}$ in Non-RGGI States (PA, DC, VA, WV)

State	RGGI Effect on Annual Average $PM_{2.5}$ in non-RGGI States (Counties weighted by population)						
	2009	2010	2011	2012	2013	2014	Average
NJ				-0.01	-0.02	-0.01	
PA	-0.06	-0.01	0.00	-0.01	-0.02	-0.01	-0.02
VA	-0.04	0.00	0.00	-0.01	-0.01	-0.01	-0.01
DC	-0.03	0.00	0.00	-0.01	-0.01	-0.01	-0.01
WV	-0.02	0.00	0.00	0.00	-0.01	0.00	-0.01

Source: Abt Associates analysis (2017).

4.4 Impacts on Public Health due to RGGI

Our estimates show that RGGI's impact on air quality in the region resulted in substantial improvements to public health throughout the Northeast, in both RGGI and non-RGGI states. Results for avoided adverse health effects and their total estimated value across all RGGI states are presented in Table 7. The number of health effects avoided in RGGI states include 240 to 540 adult mortalities, 27 to 260 non-fatal heart attacks, 145 hospitalizations (respiratory or cardiovascular), and cases of asthma ER visits, asthma exacerbations, and minor respiratory illnesses. Overall, the main driver of the value of health benefits is avoided premature mortality among adults, which constitutes over 98 percent of the total health benefits across the 2009 to 2014 study timeframe. Health benefits due to RGGI also include improvements to productivity and quality-of-life, totaling 31,000 avoided lost work days and nearly 200,000 fewer days with lower levels of activity (e.g., walking, exercising).

To express the value of benefits which occur over multiple years in present value terms, we apply 3 and 7 percent rates of discount to the flow of estimated annual benefits from 2009 to 2014.[38] Results presented in this section are based on 3 percent rate of discount; similar results based on a 7 percent rate can be found in the Appendices.

Table 7. Health Benefits due to RGGI in RGGI States[39]

Health Effect	Incidences avoided due to RGGI. 2009-2014	Monetized health benefit due to RGGI, 2009-2014 (Million 2015 dollars), 3% discount rate
Acute Bronchitis	340	$0.20
Adult Mortality	240–540	$2,400–$5,300
Asthma ER Visits	160	$0.09
Asthma Exacerbations	6,500	$0.45

[38] These rates are based on EPA's guidelines on the use of a social rate of discount in economic analyses of public environmental and health policies and programs.

[39] Public health benefits in New Jersey from 2009-2011 are included in the total public health benefits due to RGGI in RGGI States

Cardiovascular Disease Hospital Admissions	80	$4.1
Infant Mortality	0.4	$4.5
Lower Respiratory Symptoms	4,300	$0.11
Minor Restricted Activity Days	190,000	$15
Non-fatal Heart Attacks	27–260	$4.4–$44
Respiratory Hospital Admissions	65	$2.3
Upper Respiratory Symptoms	6,100	$0.25
Work Loss Days	31,000	$7.5
Total		**$2,400–$5,400**

Source: Abt Associates analysis (2017).

For health impacts outside the RGGI states, our analysis included results for Pennsylvania, the District of Columbia, Virginia, and West Virginia (Table 8). Although these jurisdictions are not part of the RGGI program, they also accrue health benefits as a result of their location downwind of a RGGI state(s) where emissions reductions occurred as a result of the program. Pennsylvania's low-end benefits estimate of $823 million is greater than the total benefits for any single RGGI state, while Virginia's benefits ($244 million) exceed the estimates for several RGGI states. In addition, the District of Columbia's total benefits are over $18 million.

Table 8. Health Benefits due to RGGI in Non-RGGI States (PA, DC, VA, WV)[40]

Health Effect	Incidences avoided due to RGGI, 2009-2014	Monetized health benefit due to RGGI, 2009-2014 (Million 2015 dollars) 3% discount rate
Acute Bronchitis	180	$0.10
Adult Mortality	130–290	$1,300 - $2,900
Asthma ER Visits	73	$0.04
Asthma Exacerbations	3,400	$0.23
Cardiovascular Disease Hospital Admissions	44	$2.2
Infant Mortality	0.25	$2.8
Lower Respiratory Symptoms	2,200	$0.06
Minor Restricted Activity Days	95,000	$7.7
Non-Fatal Heart Attacks	14–130	$2.3–$21
Respiratory Hospital Admissions	32	$1.1
Upper Respiratory Symptoms	3,200	$0.13
Work Loss Days	16,000	$3.6
Total		**$1,300–$2,900**

[40] Public health benefits in New Jersey from 2012 to 2014 are included in the total public health benefits due to RGGI in non-RGGI states.

Source: Abt Associates analysis (2017).

Because of uncertainties regarding RGGI's effect on generation and emissions in non-RGGI states, we discount the low-end range of benefits estimated by BenMAP for non-RGGI states by 50 percent to create a new low-end, before adding these to benefits for RGGI states for a cumulative estimate. The high-end benefits for non-RGGI states are not adjusted, and are equal to 100 percent of BenMAP's high-end estimate. The range of cumulative health benefits due to RGGI are shown in Table 9. The total estimated value of health benefits associated with the RGGI program range from $3.0 to $8.3 billion (2015 dollars) in the region, with a central estimate of $5.7 billion (3 percent discount rate). The benefits estimates represent the value of reductions to affected populations in the health risks associated with $PM_{2.5}$.

Table 9. Cumulative Health Benefits due to RGGI[41]

Health Effect	Avoided Health Effects due to RGGI, 2009-2014		Value of Health Benefits due to RGGI, 2009-2014 (Million 2015 dollars)		
	Low	High	Low	Central	High
Acute Bronchitis	420	510	$0.25	$0.27	$0.3
Adult Mortality	300	830	$3,000	$5,600	$8,200
Asthma ER Visits	200	230	$0.11	$0.12	$0.13
Asthma Exacerbations	8,200	9,900	$0.57	$0.63	$0.69
Cardiovascular Disease Hospital Admissions	100	120	$5.2	$5.8	$6.3
Infant Mortality	<1	<1	$5.9	$6.6	$7.3
Lower Respiratory Symptoms	5,400	6,500	$0.14	$0.15	$0.17
Minor Restricted Activity Days	240,000	280,000	$19	$21	$23
Non-Fatal Heart Attacks	35	390	$5.5	$33.5	$61.6
Respiratory Hospital Admissions	82	98	$2.8	$3.1	$3.4
Upper Respiratory Symptoms	7,700	9,300	$0.31	$0.34	$0.37
Work Loss Days	39,000	47,000	$9.2	$10.1	$11
Total			**$3,000**	**$5,700**	**$8,300**

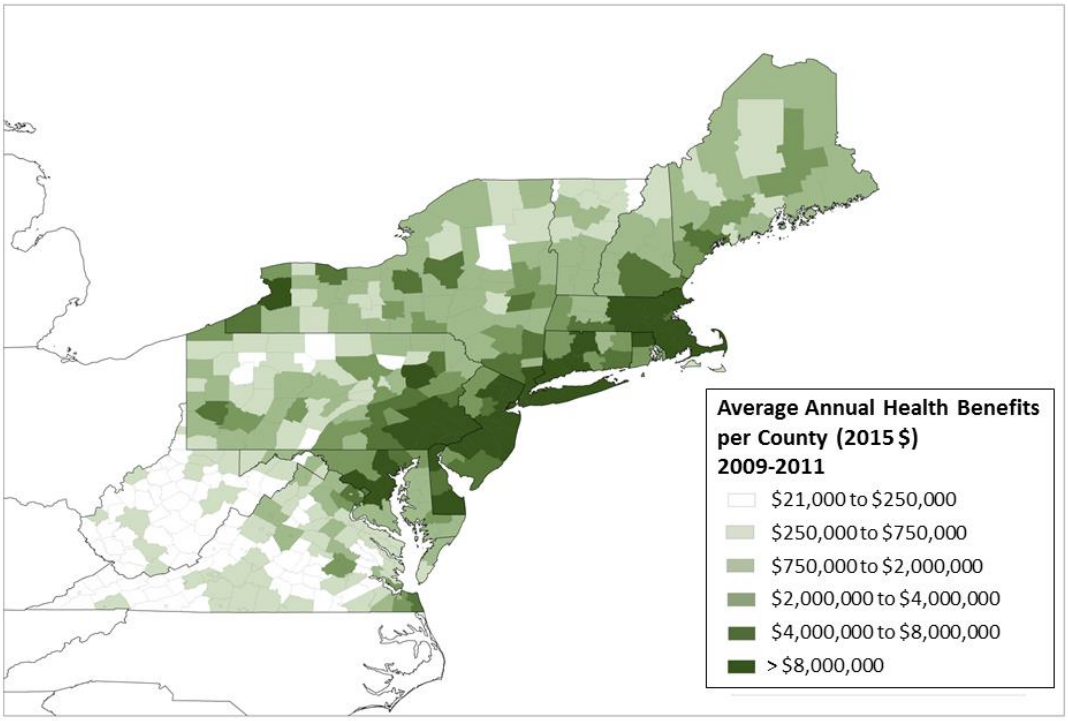
Source: Abt Associates analysis (2017).

Note: Value of avoided health effects is the sum of health benefits to states participating in RGGI and other northeastern states, based on a 3 percent rate of discount.

Figure 12 and Figure 13 show the geographic distribution of health benefits at the county level (central estimates, 3 percent discount rate). In each RGGI state, the most significant benefits were realized in 2009

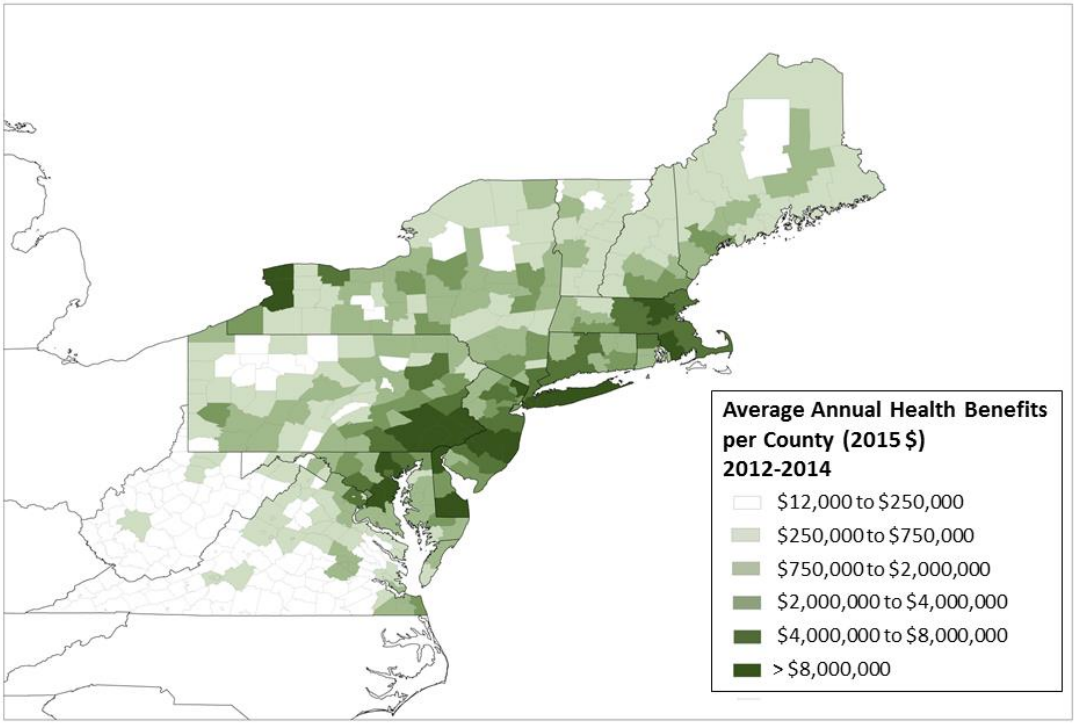
[41] Public health benefits in New Jersey from 2009-2011 are included in the total public health benefits due to RGGI in RGGI States. Public health benefits in New Jersey from 2012-2014 are included in the total public health benefits due to RGGI in non-RGGI States.

Figure 12. Annual Health Benefits of RGGI, 2009 to 2011 (Central Estimate, 3% Discount Rate)



Source: Abt Associates analysis (2017).

Figure 13. Annual Health Benefits of RGGI, 2012 to 2014 (Central Estimate, 3% Discount Rate)



Source: Abt Associates analysis (2017).

Figure 14 and Figure 15), the year with the largest estimated reductions in SO_2 emissions. State-level benefits were lower in 2010 and 2011, increased in 2012 and 2013, and decreased in 2014. Among the RGGI states, the largest health benefits by value are in New York, followed by New Jersey and Massachusetts. This is in contrast to the air quality results, which indicated the largest changes in air quality in Delaware, due to differences in population size across counties in the RGGI states. The same air quality change will result in different numbers of avoided cases (and therefore different monetized benefits) based on the affected population. For example, in 2010, $PM_{2.5}$ emissions in New York County decreased by 0.008 $\mu g/m^3$, resulting in a range of total health benefits of $4.8 to $10.8 million (2015 dollars). In the same year, the air quality change in New Castle County, DE was larger (0.014 $\mu g/m^3$), but resulted in lower benefits of $3.5 to $7.9 million (2015 dollars) (see sidebar for more information of the role of population on health benefits).

The Role of Population in Public Health Benefits in Two Maryland Counties

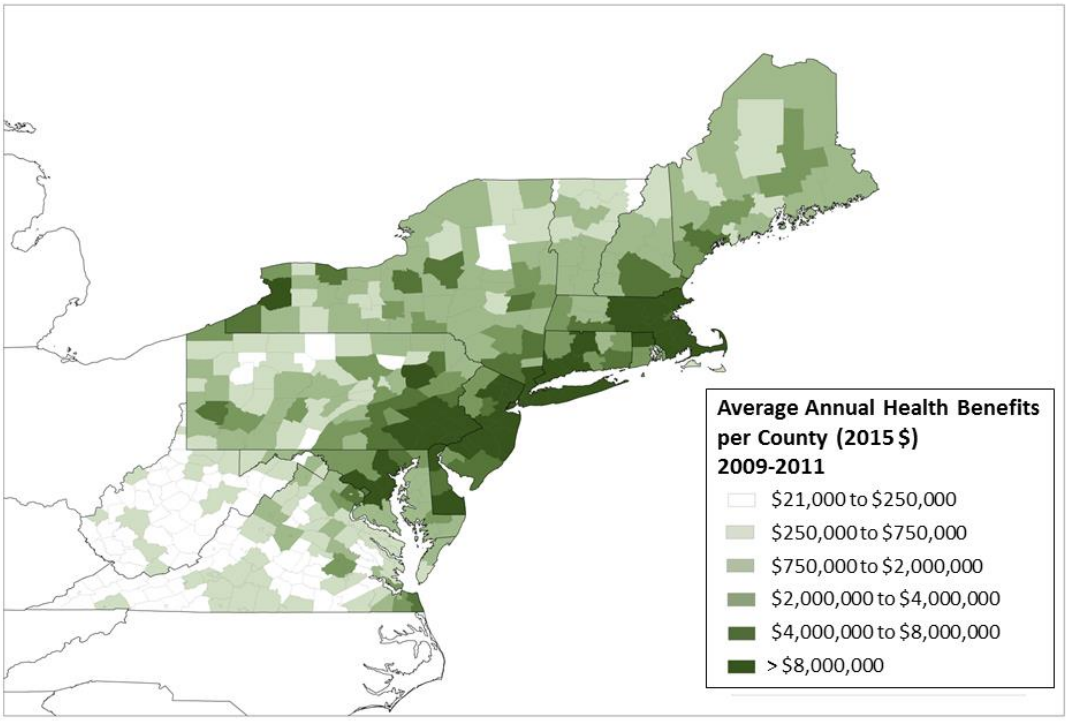
The benefits of RGGI to public health for a given county are a function of the county's population, baseline level of health, and changes to the level of ambient $PM_{2.5}$ attributable to RGGI. Because of differences in population and baseline health, counties with similar RGGI-driven $PM_{2.5}$ reductions can experience very different public health outcomes. The table shows avoided health outcomes for two counties in Maryland with different population sizes. Although RGGI results in a comparable $PM_{2.5}$ reduction in both counties (i.e., 0.022 to 0.023 $\mu g/m^3$), Baltimore County's population is about 810,000, while St. Mary's population is only 110,000. Because of these population differences, health benefits of RGGI are much more significant for Baltimore County than for St. Mary's County.

Public Health Benefits of RGGI in Baltimore County, MD and St. Mary's County, MD, 2014

Health Effect	Incidences Avoided due to RGGI, 2014	
	Baltimore County, MD	St. Mary's County, MD
Acute Bronchitis	1.2	0.20
Adult Mortality	1.0–2.3	0.10–0.23
Asthma ER Visits	0.65	0.06
Asthma Exacerbations	23	3.7
Cardiovascular Disease Hospital Admissions	0.37	0.04
Infant Mortality	<0.01	<0.01
Lower Respiratory Symptoms	15	2.5
Minor Restricted Activity Days	690	94
Non-Fatal Heart Attacks	0.12–1.1	0.01–0.08
Respiratory Hospital Admissions	0.28	0.03
Upper Respiratory Symptoms	22	3.6
Work Loss Days	115	16

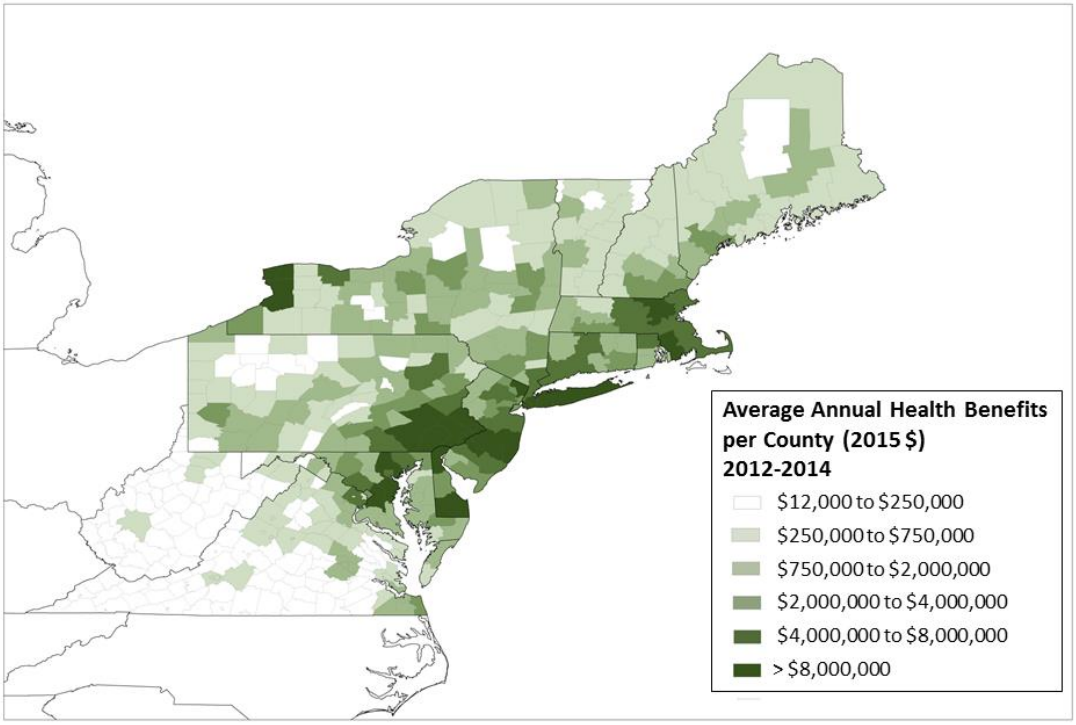
Source: Abt Associates analysis (2017).

Figure 12. Annual Health Benefits of RGGI, 2009 to 2011 (Central Estimate, 3% Discount Rate)



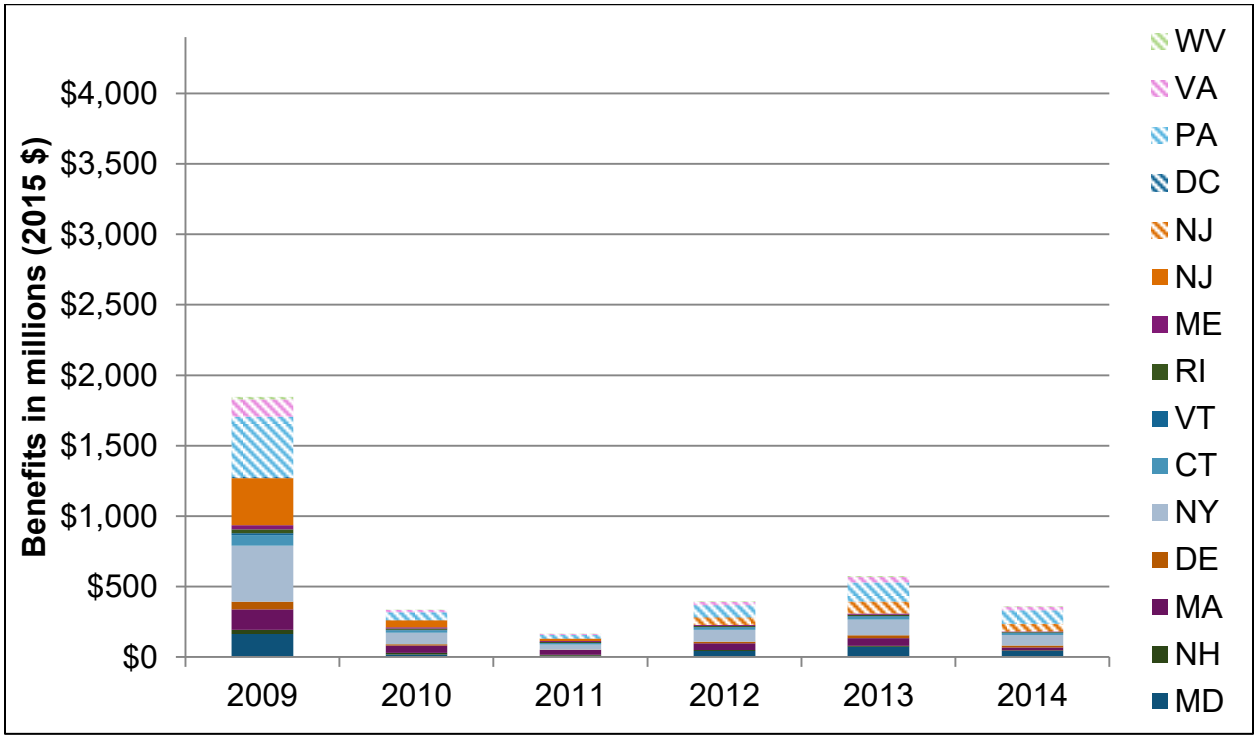
Source: Abt Associates analysis (2017).

Figure 13. Annual Health Benefits of RGGI, 2012 to 2014 (Central Estimate, 3% Discount Rate)



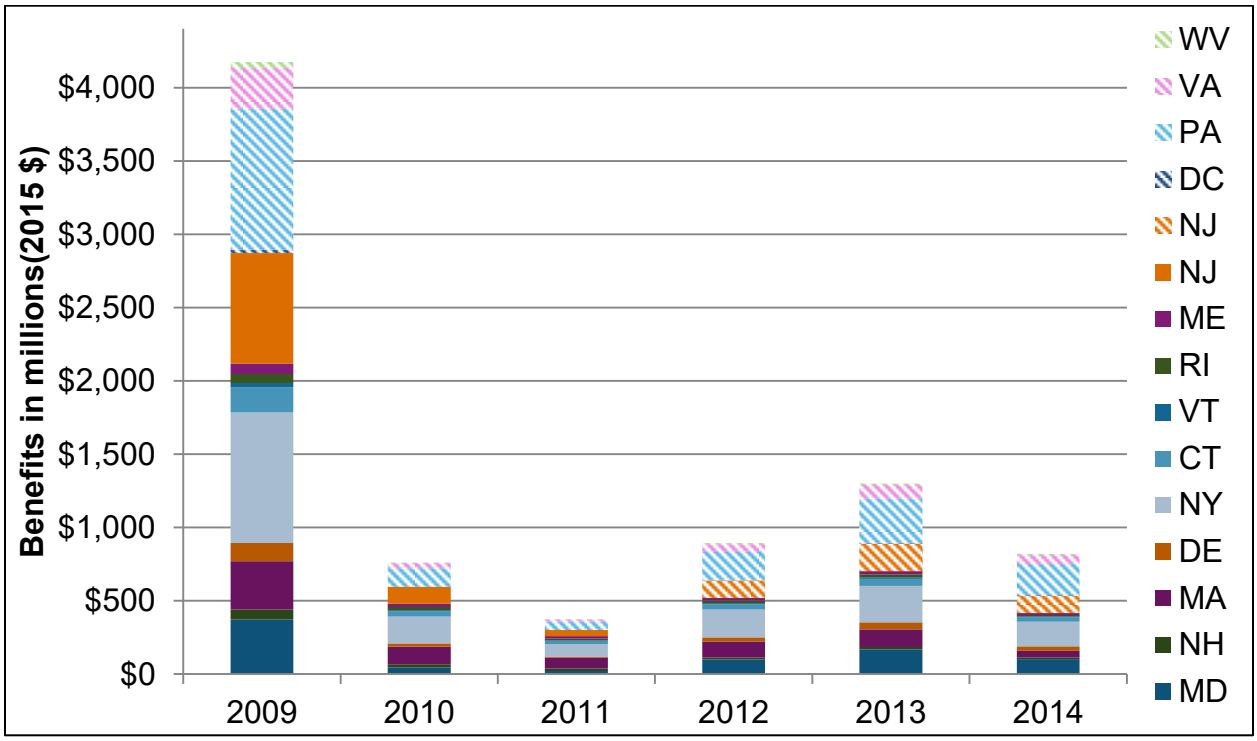
Source: Abt Associates analysis (2017).

Figure 14. RGGI Public Health Benefits by State (Low Estimate, 3% Discount Rate)



Source: Abt Associates analysis (2017).

Figure 15. RGGI Public Health Benefits by State (High Estimate, 3% Discount Rate)



Source: Abt Associates analysis (2017).

4.5 Key Findings and Implications

During the first six years of RGGI implementation, the program resulted in sizable reductions in key criteria air pollutants, especially SO_2 emissions, which contribute to the formation of $PM_{2.5}$. RGGI-induced reductions in ambient $PM_{2.5}$ occurred throughout densely populated areas of the northeastern corridor all the way to western New York and into New England, and resulted in significant benefits to human health. These benefits include hundreds of avoided cases of premature deaths, heart attacks, asthma attacks, and hospital admissions, and tens of thousands of avoided cases of other health symptoms, lost work days, and restricted activities. The estimated value of the health, productivity, and quality-of- life benefits associated with RGGI ranges from $3.0 billion to $8.3 billion, with a central estimate of $5.7 billion (2015 dollars, 3 percent discount rate).

RGGI's effect on annual air quality and public health are most significant in 2009 and 2013. This pattern is consistent with RGGI's two effects on wholesale power markets: 1) changes in power prices to absorb CO_2 allowance costs, which results in a shift of dispatch to lower-carbon sources, and 2) investments in energy efficiency, which reduce electricity demand and emissions. In addition, there is evidence that plant owners took early action to reduce CO_2 emissions in anticipation of RGGI.

As noted above, RGGI-induced changes at a relatively small number of legacy coal plants drive a high proportion of RGGI's total reductions in key air pollutants and health benefits. The fleet of power plants in RGGI states will be, on average, cleaner in the near future than the current fleet,[42] so future RGGI-induced reductions in generation are likely to result in lower total health benefits going forward.

However, the cleaner electricity grid does create opportunities for additional health benefits if energy demand from other sectors—transportation and buildings—shifts onto to a cleaner grid in RGGI (and neighboring) states, a process known as "electrification." Reductions of air pollutants and health benefits from decarbonizing other energy demand could be significant. For example, a 2016 study assessed future health and climate benefits that would occur if the eight northeastern states participating in the Zero Emission Vehicle (ZEV) program[43] transitioned to a vehicle fleet of about 65 percent ZEVs by 2050 (American Lung Association in California, 2016). According to the study, this would result in about $12 billion in annual health benefits. [44] Many RGGI states (e.g., Massachusetts, Rhode Island) are currently implementing or developing GHG mitigation plans to achieve 80 percent reductions in GHG emissions

[42] A number of states in the region are implementing GHG mitigation plans that require 80 percent reductions in GHG emissions by 2050, relative to 1990 levels.

[43] The ZEV program requires that automakers meet a threshold of electric vehicle sales in participating states. The exact number of electric vehicles required is linked to each automaker's total sales within the state. The eight northeastern states participating in the ZEV program, along with California and Oregon, include: Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island, and Vermont.

[44] The study reports state-level combined health and climate benefits, and we assume that health benefits constitute 62 percent of combined benefits. This assumption is based on the fact that health benefits across all states constitute 62 percent of combined health and climate benefits across all states.

by 2050,[45] and these plans include strategies for electrification of energy used in light-duty vehicles and building heating and cooling.

As in any analysis, there were certain uncertainties in data, assumptions, and models used in this study which influenced estimates. Table 10 below describes these sources of uncertainty and their potential impact on estimated changes in emissions, air quality, and health benefits due to RGGI, as well as our approach to addressing individual uncertainties within models or through quantified sensitivity cases. The fact that quantitative estimates of energy savings from RGGI investments in efficiency which persist after 2014 and reductions in ozone due to RGGI are excluded from this analysis implies a likely underestimation of benefits. We also applied a sensitivity factor of 50 percent to health benefits estimated for non-RGGI states to account for the lack of conclusive information describing RGGI's incremental effect on generation and emissions in these states. As such, our estimates of total health benefits due to RGGI are probably conservative.

Table 10. Key Uncertainties in the Analysis

Source of Uncertainty in the Analysis	Impact on Estimates	Likely Significance on Estimates of Health Benefits
Analysis excludes avoided emissions, air quality, and health benefits that occur after 2014 resulting from states' investments in energy efficiency from 2009 to 2014.	**Underestimation.** The magnitude of these excluded benefits is not known, but could be significant given the magnitude of EE investments particularly in 2013 and 2014.	Possibly significant.
Analysis excludes health benefits associated with reductions in ozone.	**Underestimation.** The effect of ozone reductions on health benefits is known to be smaller in magnitude than that of reductions in ambient $PM_{2.5}$.	Probably minor.
Analysis excludes changes in emissions in non-RGGI states as a result of RGGI.	**Overestimation**. Unable to determine magnitude based on current information, but the potential for lower benefits is addressed through a sensitivity factor that discounts benefits in non-RGGI states by 50 percent.	Possibly significant.
Gaps in baseline emissions datasets.	**Indeterminate.** Gaps for missing years in EPA emissions databases were addressed by adjustments to data describing adjacent years.	Probably minor.

[45] The base year against which each of these states calculates their 2050 emissions reduction goal in their GHG mitigation plans varies—some states use a base year of 1990, while others use 2001.

Source of Uncertainty in the Analysis	Impact on Estimates	Likely Significance on Estimates of Health Benefits
Uncertainties in assumptions and inputs used in dispatch, air quality, and health benefits modeling.	**Indeterminate.** Low- and high-end estimates from the BenMAP model account for uncertainties in the relationship between population exposures and health effects. Historical actual data were used in dispatch and air quality models, thereby reducing some sources of error.	Possibly significant.

Source: Abt Associates analysis (2017).

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Appendix A – Emissions Data Sources and Analysis

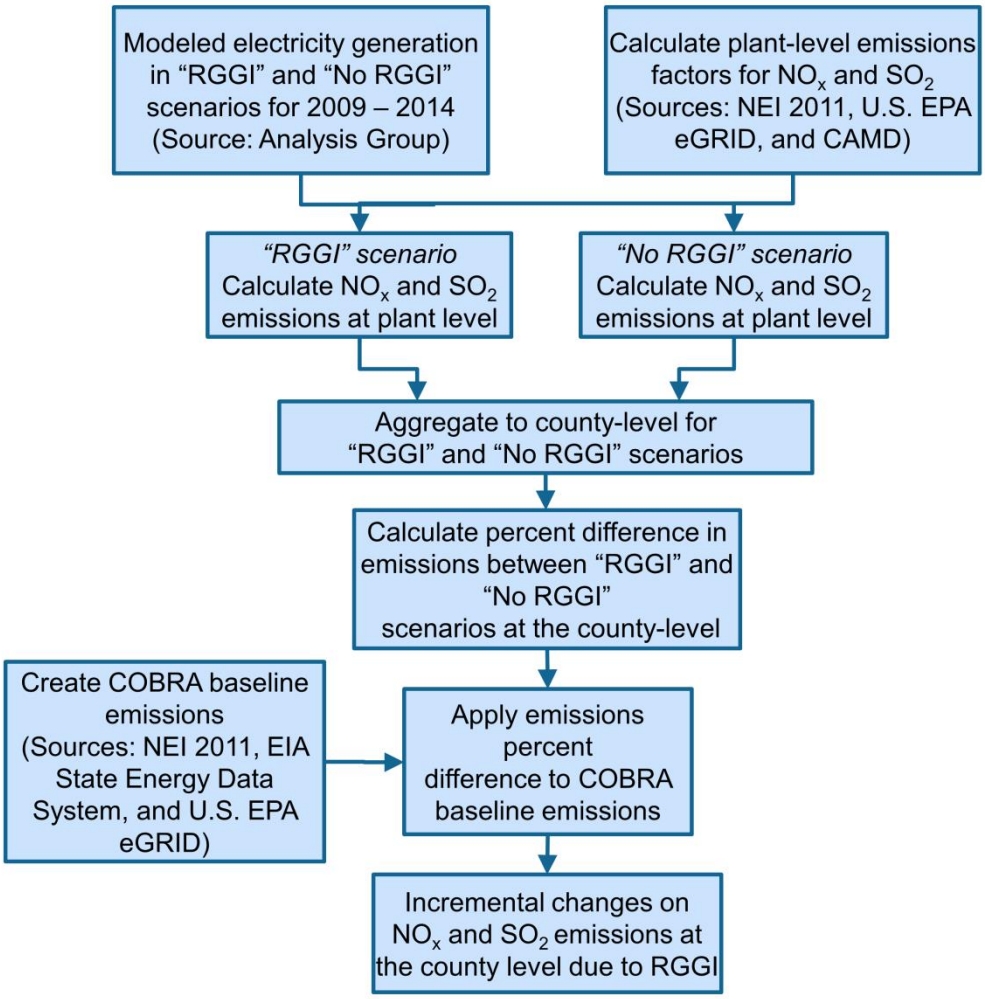
Detailed Analytic Approach

We developed a baseline of emissions for the RGGI scenario from actual emissions in the EPA's 2011 National Emissions Inventory (NEI) data. We chose the NEI dataset because it enabled us to represent emissions inventories from all sectors in the economy. This is necessary for Step 2 of our analysis because COBRA models changes in air quality based on a complete inventory of criteria pollutant emissions from all sectors (e.g., power plants, transportation, industrial processes.

We calculated emissions for the modeled electricity generation levels under the RGGI and No RGGI scenarios by (1) calculating plant-level emission factors and (2) applying plant-level emissions factors to modeled generation levels. We calculated plant-level SO_2 and NO_x emissions factors (tons pollutant/MWh generated) by dividing NEI-derived baseline emissions by actual generation. We created unique emissions factors for each year, which enabled us to reflect the effects of pollution control installations, operational characteristics, and changes in fuel mix for each plant. We applied these emissions factors to the modeled generation levels under RGGI and No RGGI to determine emissions under RGGI and No RGGI, respectively. Our workflow to calculate incremental changes in NO_x and SO_2 emissions at the county level is illustrated in Figure 16.

We then aggregated the modeled RGGI and No RGGI emissions to the county level and calculated the ratio of emissions between the RGGI and No RGGI scenarios. We applied this ratio to the actual RGGI emissions baseline to construct the counterfactual emissions inventory for No RGGI. The difference between the RGGI emissions inventory and the RGGI emissions baseline is the incremental change in emissions due to RGGI, which we input into COBRA under Step 2.

Figure 16. Approach to Estimating County-Level Changes in Emissions due to RGGI



Source: Abt Associates analysis (2017).

Description of Datasets Used

Analysis Group Datasets

We used results of modeling runs conducted by Analysis Group as part of their 2011 and 2015 retrospective studies of RGGI's economic impacts. These datasets provided estimates of annual plant-level electricity generation for all power plants located in RGGI states, for the RGGI and No RGGI scenarios (Analysis Group, 2011, 2015).

Analysis Group modeled electricity generation per unit with power system dispatch models, which simulate the optimal distribution of the electric power system load among generation facilities. Analysis Group used GE Energy's Multi-Area Production Simulation (MAPS) model for the first compliance period (see Analysis Group, 2011) and the PROMOD model for the second compliance period (see Analysis Group, 2015).

These dispatch models are useful for this retrospective analysis of RGGI because they compute optimal dispatch based on observed fuel prices, transmission system constraints, and operational constraints at a high geographic and temporal resolution. However, dispatch models cannot perfectly simulate power producers' actual, real-world decisions. For example, dispatch models tend to show that very small changes in marginal costs lead to significant changes in dispatch patterns, which is not always the case.

The modeled "RGGI" scenario reflects actual "RGGI" data accurately when aggregated to the regional scale. However, differences between the modeled "RGGI" scenario and actual "RGGI" data emerge at the county or plant level. Accuracy at the plant level is necessary to model public health benefits, because the estimated effect of changes in generation on emissions is highly dependent on the age, fuel use, and emissions controls of a given plant, and the effect of changes in emissions on public health are highly dependent on the emissions' location. We adopt a percent difference approach to deal with differences between the modeled RGGI scenario and actual RGGI data, as described in the main text.

National Emissions Inventory

The NEI is a comprehensive estimate of air emissions that EPA develops from data reported primarily from state, local, and tribal air agencies. The NEI includes emissions from multiple sources, including point sources (e.g., power plants), non-point sources (e.g., residential heating), on-road sources (e.g., light-duty vehicles), and non-road sources (e.g., boats, lawn and garden equipment). NEI datasets are available from 2008, 2011, and 2014. For our analysis, we used the 2011 NEI dataset. We estimated annual power plant emissions for each year in the 2009 to 2014 period by modifying the NEI 2011 baseline. We estimated plant-level emissions changes relative to 2011 based on fuel use ratios from the State Energy Data System and annual emissions factor ratios from the EPA Emissions and Generation Resources Integrated Database (eGRID). We also cross-checked our annual plant-level emissions estimates with other data sources, such as EPA's Clean Air Markets Division (CAMD), and spot-corrected our baseline as necessary.

EPA Emissions and Generation Resource Integrated Database

EPA's eGRID contains environmental data from all U.S. plants that supply power to the electric grid and provide data to the federal government. The database was developed by Abt Associates and CAMD. We use eGRID's plant-level SO_2 and NO_x emissions rates to adjust our annual emissions inventories to account for installation of emissions controls. Plant-level SO_2 and NO_x emissions rates are available for 2009, 2010, 2012, and 2014. For years of interest without a corresponding eGRID dataset, we calculate average emissions rates from adjacent years for which data are available.

U.S. Energy Information Administration (EIA) Annual Electric Generator Capacity Data (Form EIA-860)

The Annual Electric Generator Data is compiled from submissions of survey Form EIA-860. Form EIA-860 gathers generator-level data from all U.S. power plants with total nameplate capacity of one megawatt or greater. We used plant-level data for generators surveyed in 2009-2014. We used Form EIA-860 to identify the county in which plants are located.

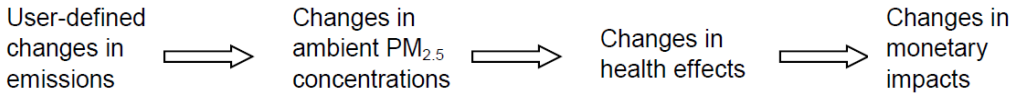
Appendix B – Estimating Air Quality Changes: Co-Benefits Risk Assessment (COBRA) Model

To estimate the air quality impacts of RGGI in 2009-2014, we used EPA's COBRA model. COBRA is a free screening tool that helps state and local governments evaluate the costs and benefits of clean energy and climate mitigation policies. COBRA provides preliminary estimates of the effects of air pollutant emission changes (e.g., NO_x, SO_2, and $PM_{2.5}$) on ambient air concentrations of $PM_{2.5}$, translates the estimated changes in ambient $PM_{2.5}$ concentrations into the number of avoided adverse health effects, and then provides a monetary value of the avoided health effects. COBRA enables policymakers and planners to identify and highlight air quality and public health co-benefits achieved through energy efficiency or renewable energy policies.

COBRA Model Components

Abt Associates originally developed COBRA in 2002 for EPA and continues to support updates of the screening tool. The model consists of four components, shown in Figure 17.

Figure 17. Components of the COBRA Model



Source: *COBRA User Manual* (U.S. EPA, 2015c).

A brief explanation of the two of the four components of the model that were used in this analysis is included below.[46] In lieu of COBRA's health valuation functions, we used the BenMAP model described in the next section.

User Inputs of Emissions Changes

COBRA contains baseline emissions estimates based on the National Emissions Inventory. Note that we prepared customized versions of the COBRA model that contain baseline emissions estimates for each modeling year 2009-2014 (see Section 3.2). We then created COBRA scenarios by entering increases or decreases to the baseline emissions estimates.

Changes in Air Quality (i.e., ambient $PM_{2.5}$ concentrations)

Based on changes in emissions levels, the COBRA model then calculates changes in particulate matter, which reflect changes in air quality. Specifically, COBRA estimates $PM_{2.5}$ concentrations using a simple air quality model known as the Phase II Source-Receptor (S-R) Matrix. The S-R Matrix consists of fixed transfer coefficients that reflect the relationship between annual average $PM_{2.5}$ concentration values at a single receptor in each county (a hypothetical monitor located at the county centroid) and the contribution by $PM_{2.5}$ species to this concentration from each emission source (E.H. Pechan & Associates Inc., 1994). COBRA models the formation of secondary $PM_{2.5}$ from NO_x and SO_2 by (1) assuming up to 25 percent of NO_x and 100 percent of SO_2 transform into ammonium nitrate and ammonium sulfate, respectively,

[46] For more detailed information, see the *COBRA User Manual* (U.S. EPA, 2015c).

depending on the limiting concentration of ammonia, (2) modeling secondary reactions among gaseous and particulate species, and (3) calibrating COBRA modeling results to measured $PM_{2.5}$ values.

Benefits of COBRA

The COBRA model allows us to quickly estimate air quality impacts based on a simplified air quality model. COBRA displays county-level results in both tabular and geographic formats. The mapping feature allows users to see changes in ambient $PM_{2.5}$ levels at the county level.

Limitations of COBRA

More sophisticated (and resource-intensive) air quality modeling approaches are available and would provide more refined estimates of the benefits of emissions reductions. Importantly, COBRA does not account for all air pollutants, such as ozone, carbon dioxide, and mercury. Therefore, the health benefits based on COBRA air quality results are likely a conservative estimate because many health impacts are exacerbated by other harmful air pollutants but are not included in the scope of the COBRA model.

Another key limitation of COBRA is that the health effects inputs cannot be easily customized. COBRA relies on population, incidence (i.e., the baseline probability of a health effect), and income data for a specific modeling year. Therefore, we did not use the health impact and valuation components of COBRA in our analysis of RGGI, and instead relied upon the BenMAP model.

Appendix C – Estimating Changes in Public Health: Benefits Mapping and Analysis (BenMAP) Model

Abt Associates designed and implemented the original BenMAP model for EPA, which was the first publicly available model for estimating the number and economic value of health impacts resulting from changes in air quality. EPA's current version of BenMAP (known as BenMAP-Community Edition) is being deployed around the world by governments, researchers, and policy analysts for generating monetized estimates of public health improvements resulting from reductions in air pollutants. For example, BenMAP has been used for local- and regional-scale analyses (e.g., Cohan et al., 2007; Nowak et al., 2013) and climate assessments (e.g., Hill et al., 2009; Tagaris et al., 2009).

We estimated the public health impacts of RGGI in 2009-2014 using the BenMAP model, Version 4.0.67. This is a legacy version of BenMAP that allows us to use configuration files EPA used for the 2012 PM National Ambient Air Quality Standards (NAAQS) Regulatory Impact Analysis (referred to below as the "2012 PM RIA configuration").[47]

We input COBRA-generated county ambient $PM_{2.5}$ estimates into BenMAP, which BenMAP used to calculate RGGI's effect on $PM_{2.5}$ relative to observed ambient $PM_{2.5}$ for 2009-2014. We selected BenMAP over COBRA for this step of the analysis because BenMAP allows us to capture changes in baseline population, incidence, and valuation over the study period. While COBRA is an appropriate tool for estimating ambient air quality, the fact that its datasets are tied to a specific calendar year limits its representation of how air quality affects public health over time.

BenMAP linked air quality changes to public health metrics by applying empirical relationships between $PM_{2.5}$ and multiple health effects.[48] BenMAP applied these statistical relationships to population datasets for 2009-2014. BenMAP uses county-level population projections based on the 2010 U.S. Census of Population and Housing and forecasting models developed by Woods and Poole (2011).

Based on the 2012 PM RIA configuration, BenMAP monetized the health impacts using "unit values" for each health endpoint (presented in Table 11). The unit values are based on published estimates of the costs of treating the illness (which can include both direct medical costs and costs of lost productivity), or the willingness to pay (WTP) to avoid the illness or to reduce the risk of premature death (i.e., value per statistical life, VSL). The unit values based on WTP estimates reflect expected growth in real income over time. This is consistent with economic theory, which argues that WTP for most goods (such as health risk reductions) will increase if real incomes increase.

In BenMAP, we estimated economic values in 2015 dollars and using income levels for each year of the analysis (e.g., 2009 income levels for valuing health impacts for 2009). In Table 11, we present the unit values at 2014 income level. Because some of the health benefits from emissions reductions in a particular year are expected to occur over several years, BenMAP discounts the estimated stream of

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[47] In BenMAP, configuration files specify the health impact and valuation functions, as well as settings for aggregation and pooling across the incidence and valuation results.

[48] The health impact functions are described in detail in Appendix E of the *BenMAP User's Manual* (U.S. EPA, 2012).

economic benefits to the analysis year using either a 3 percent or a 7 percent discount rate. We further adjusted all results to 2015 present values.

Table 11. Health Effects and Their Economic Values (2015 dollars/case)

Avoided Health Effect	Economic Value (2015 dollars, 2014 Income Level)[1]
Time-varying costs[2]	
Adult Mortality[1] (3% discount rate)	$8,937,339
Adult Mortality[1] (7% discount rate)	$7,960,346
Non-Fatal Heart Attacks (3% discount rate)	$38,253–$298,337
Non-Fatal Heart Attacks (7% discount rate)	$36,167–$286,735
Costs incurred in the year of exposure	
Infant Mortality[3]	$9,961,679
Hospital Admissions (Respiratory, Cardiovascular-related)[4]	$17,135–$46,318
Asthma Emergency Room Visits	$447–$534
Acute Bronchitis	$513
Respiratory Symptoms (Upper, Lower)	$22–$36
Asthma Exacerbations (attacks, shortness of breath, and wheezing)	$62
Minor Restricted Activity Days	$73
Work Loss Days[4]	$160

Source: U.S. EPA (2012d and 2012e).

1. The unit values based on WTP estimates reflect expected growth in real income over time. When estimating health benefits, we used the income level specific to each analysis year. In this table, we present the values at 2014 income level.

2. Most health effects and their economic values are expected to occur in the year of analysis. However, not all avoided cases of adult mortality are expected to occur in the year of analysis. In addition, while avoided cases of non-fatal heart attacks are expected to occur in the same year as the emissions change, the costs associated with this health effect would occur over multiple years. Thus, BenMAP uses discount rates of 3 percent and 7 percent to calculate the value of these health effects in present terms.

3. Following U.S. EPA (2012a), we assume that some of the incidences of premature adult mortality related to $PM_{2.5}$ exposures occur in a distributed fashion over the 20 years following exposure. This lag adjustment does not apply to infant mortality because Woodruff et al. (1997) estimated the number of infant deaths occurring in the same year as the emissions change. We applied the lag adjustments to the BenMAP output.

4. BenMAP uses county-specific median daily wages to value work loss days and opportunity costs for hospital admissions. In this table, we report unit values based on the national median daily wage.

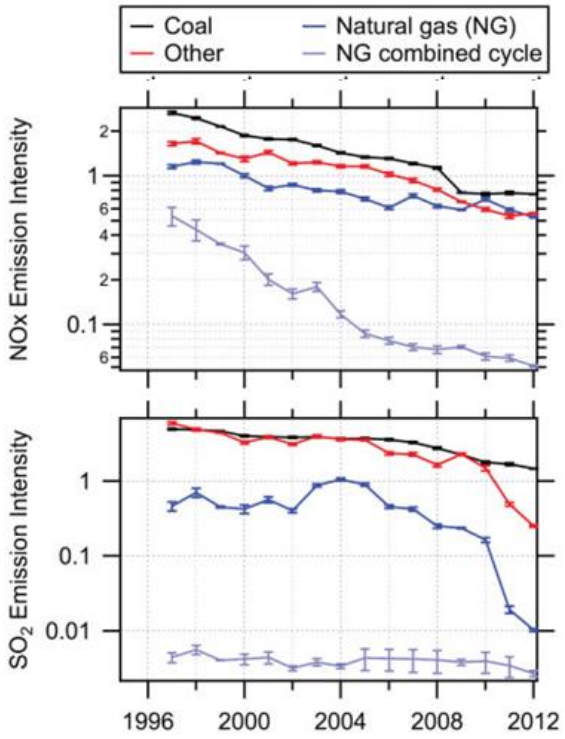
The resulting health impact results do not capture all uncertainty surrounding BenMAP's inputs. This analytic step introduces several uncertainties, including population forecasts and the VSL. Another source of uncertainty introduced in this analytic step relates to whether there is regional variability in some inputs. Because BenMAP's health impact and valuation functions represent national-level relationships,

the accuracy of regional-level analyses may be improved by identifying region-specific relationships from the literature.[49]

[49] Further details on uncertainty in BenMAP inputs are provided in the appendices of the *BenMAP User's Manual* (U.S. EPA, 2015a).

Appendix D – Supplementary Figures

Figure 18. NO_x and SO_2 Emission Rates across Generation Technologies and Fuel Types



Source: Adapted from de Gouw et al. (2014).

Table 12. Health Benefits due to RGGI in RGGI States, 7% Discount Rate

Health Effect	Incidences avoided due to RGGI from 2009-2014	Monetized health benefit due to RGGI from 2009-2014 (Million 2015 dollars), 7% discount rate
Acute Bronchitis	340	$0.23
Adult Mortality	240–540	$2,500–$5,700
Asthma ER Visits	160	$0.11
Asthma Exacerbations	6,500	$0.54
Cardiovascular Disease Hospital Admissions	80	$4.9
Infant Mortality	0.4	$5.4
Lower Respiratory Symptoms	4,300	$0.13
Minor Restricted Activity Days	190,000	$18
Non-fatal Heart Attacks	27–260	$5.1–$47
Respiratory Hospital Admissions	65	$2.7
Upper Respiratory Symptoms	6,100	$0.3
Work Loss Days	31,000	$8.9
Total		**$2,500–$5,700**

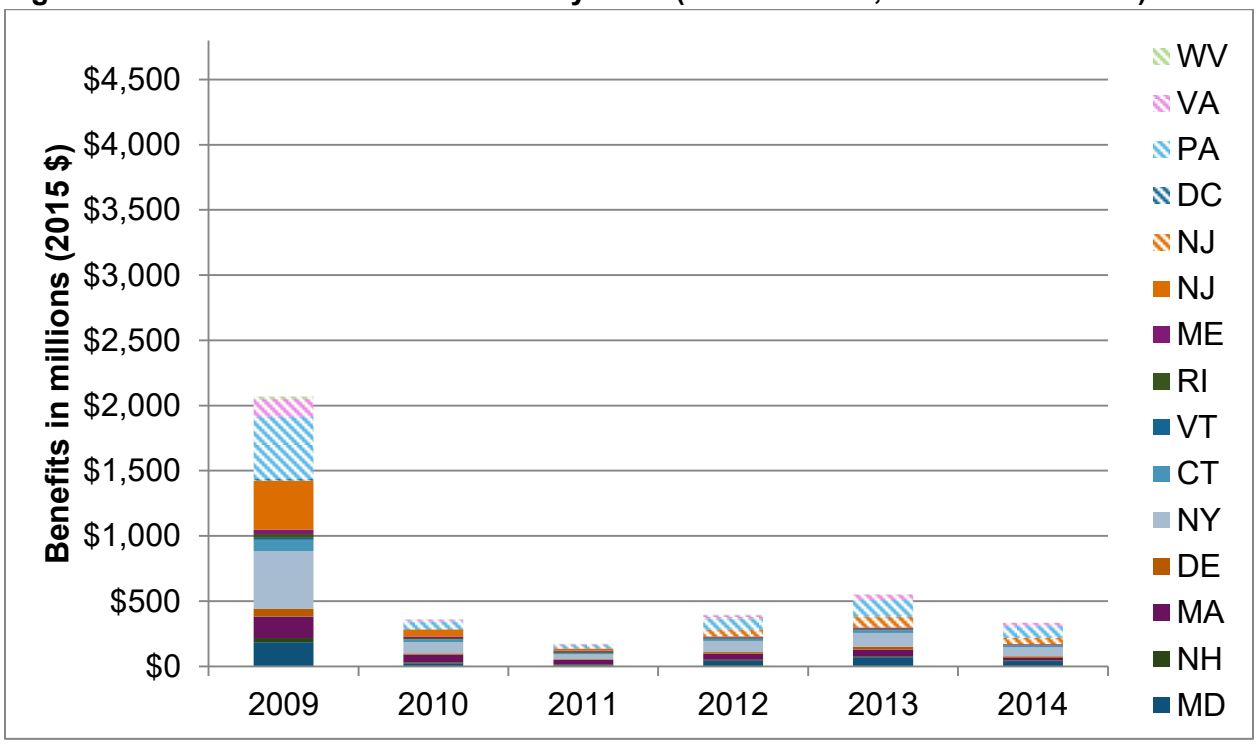
Source: Abt Associates analysis (2017).

Table 13. Health Benefits due to RGGI in Non-RGGI States, 7% Discount Rate

Health Effect	Incidences avoided due to RGGI from 2009-2014	Monetized health benefit due to RGGI from 2009-2014 (Million 2015 dollars) 7% discount rate
Acute Bronchitis	180	$0.12
Adult Mortality	130–290	$1,300–$3,000
Asthma ER Visits	73	$0.05
Asthma Exacerbations	3,400	$0.27
Cardiovascular Disease Hospital Admissions	44	$2.6
Infant Mortality	0.25	$3.3
Lower Respiratory Symptoms	2,200	$0.07
Minor Restricted Activity Days	95,000	$9
Non-Fatal Heart Attacks	14–130	$2.6–$24
Respiratory Hospital Admissions	32	$1.3
Upper Respiratory Symptoms	3,200	$0.15
Work Loss Days	16,000	$4.2
Total		**$1,300–$3,000**

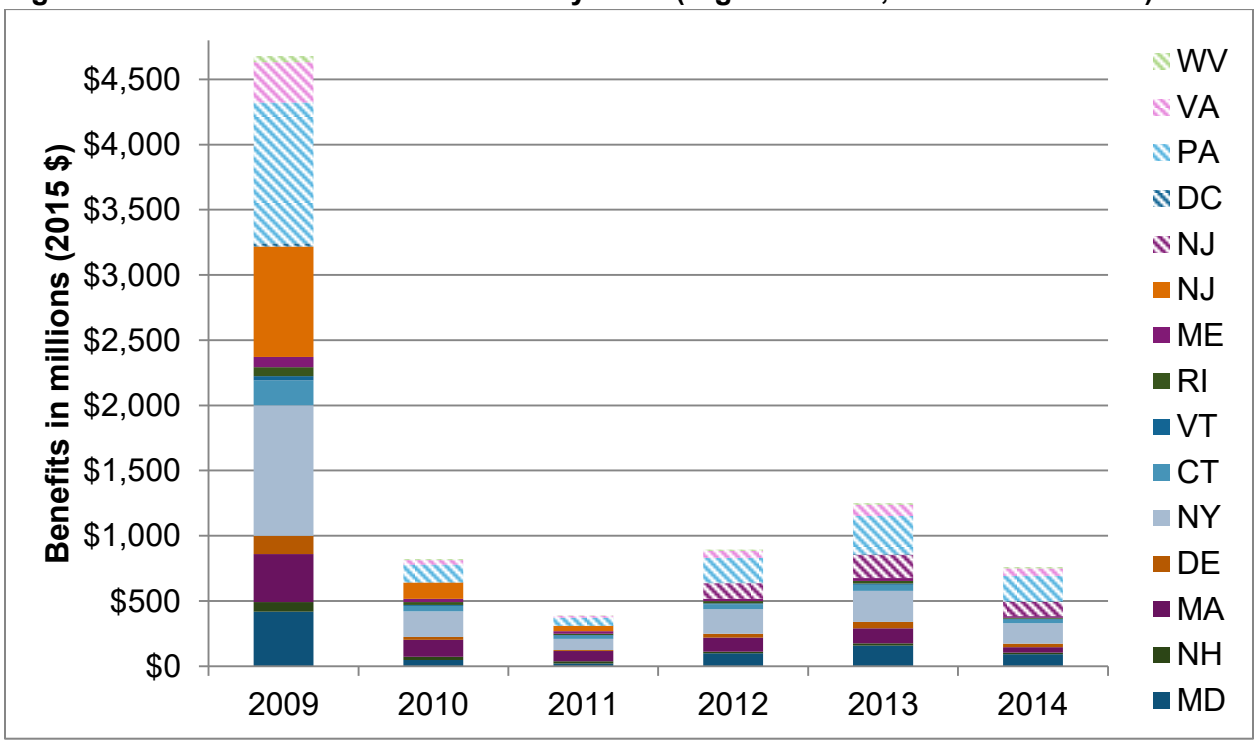
Source: Abt Associates analysis (2017).

Figure 19. RGGI Public Health Benefits by State (Low Estimate, 7% Discount Rate)



Source: Abt Associates analysis (2017).

Figure 20. RGGI Public Health Benefits by State (High Estimate, 7% Discount Rate)



Source: Abt Associates analysis (2017).

Attachment 49

A Section 508–conformant HTML version of this article is available at https://doi.org/10.1289/EHP6706.

Co-Benefits to Children's Health of the U.S. Regional Greenhouse Gas Initiative

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Background: While various policies have been implemented globally to mitigate climate change and reduce exposure to toxic air pollutants, policy assessments have considered few if any of the benefits to children.

Objective: To comprehensively assess the co-benefits of climate change mitigation to children, we expanded the suite of adverse health outcomes in the U.S. Environmental Protection Agency's Benefits Mapping and Analysis Program (BenMAP) to include additional outcomes associated with prenatal and childhood exposure to ambient fine particulate matter ($PM_{2.5}$). We applied this newly expanded program to an assessment of the U.S. Regional Greenhouse Gas Initiative (RGGI), the United States' first regional market-based regulatory program designed to reduce greenhouse gas emissions from the electric power sector within the Northeast.

Methods: We used calculated changes in ambient $PM_{2.5}$ concentrations for the period 2009–2014, with newly incorporated concentration–response (C-R) functions to quantify changes in the incidence of preterm birth (PTB), term low birth weight (TLBW), autism spectrum disorder (ASD), and asthma. These outcomes are causally or likely to be causally related to $PM_{2.5}$ exposure. Cost per case estimates were incorporated to monetize those changes in incidence.

Results: The estimated avoided cases of adverse child health outcomes included 537 asthma cases, 112 preterm births, 98 cases of ASD, and 56 cases of TLBW, with an associated avoided cost estimate ranging from $191 to $350 million. In a previous analysis of health benefits of RGGI, the only benefits accruing to children were limited to prevented cases of infant mortality and respiratory illnesses, with a monetized impact of $8.1 million—only 2–4% of the new results attributable to RGGI.

Conclusion: The results of this innovative analysis indicate that RGGI has provided substantial child health benefits beyond those initially considered. Moreover, those health benefits had significant estimated economic value. https://doi.org/10.1289/EHP6706

Introduction

Toxic air pollutants such as ambient fine particulate matter [PM ≤2.5 μm in aerodynamic diameter ($PM_{2.5}$)] and the major climate-altering gas, carbon dioxide (CO_2) emitted by fossil fuel combustion, are taking a significant toll on children's health and jeopardizing their future well-being. They are also major contributors to inequality worldwide (Perera 2017). Because of their biological vulnerability and rapid development, the developing fetus and young child are disproportionately affected by air pollution and climate change (Perera 2017). This is especially true in populations where poverty and environmental injustice compound the effects. A number of climate change mitigation policies and air pollution regulations have been implemented around the world to reduce fossil fuel combustion emissions, with sizeable health and economic benefits documented or projected. However, assessments of the public health benefits of such policies have considered few, if any, benefits to children; and their lifelong consequences have generally not been factored into the assessments of avoided costs. These include the U.S. Clean Air Act Amendments (U.S. EPA 2011), the Clean Power Plan (Driscoll et al. 2015), California's cap and trade program and low-cost fuel standards (O'Connor et al. 2014), the City of London Air Quality Strategy (City Of London Corporation 2019), and the Paris Climate Accord (Markandya et al. 2018). This omission has resulted in a serious undercounting of potential health benefits for this vulnerable population.

The Regional Greenhouse Gas Initiative (RGGI) is the United States' first regional market-based regulatory program designed to reduce greenhouse gas emissions from the electric power sector (RGGI Inc. 2019a). RGGI was established in the northeastern region in 2005 through a Memorandum of Understanding between the governors of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont. In 2007, the program was expanded to include Maryland, Massachusetts, and Rhode Island, and in 2008 it held an initial auction for emissions allowances (Center for Climate and Energy Solutions 2019). Under RGGI program, participating states are expected to reduce their annual CO_2 emissions from the power sector by 45% below 2005 levels by 2020, and by an additional 30% by 2030 (Center for Climate and Energy Solutions 2019). RGGI included 10 states during its initial compliance period starting in 2009. The program is still currently operating with 9 of the original states, with New Jersey having withdrawn in 2012 but planning to rejoin in 2020 (Center for Climate and Energy Solutions 2019).

RGGI places limits on CO_2 emissions from new and existing fossil-fuel-fired electric generating units (EGUs) in the program area with a minimum capacity of 25 MW. Regulated EGUs must obtain allowances for each short ton of emitted CO_2. Allowances are auctioned quarterly and may be sold or traded between EGUs. Auction revenues have been reinvested to accelerate renewable energy use, improve energy efficiency, and support other public benefit programs (RGGI Inc. 2019a).

Although RGGI is focused on reducing greenhouse gas emissions, it also reduces emissions of other pollutants, such as $PM_{2.5}$, nitrogen oxides (NO_x), and sulfur dioxide (SO_2) (Manion et al. 2017). NO_x and SO_2 react in the atmosphere to form $PM_{2.5}$, which has a well-documented relationship with multiple adverse health outcomes, including respiratory and cardiovascular effects, premature mortality, and, more recently, adverse birth outcomes,

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respiratory illness, and neurodevelopmental problems in children (Perera et al. 2019).

Abt Associates previously analyzed health impacts of the first two compliance periods of RGGI (2009–2014) (Manion et al. 2017). The analysis estimated the reduction in NO_x and SO_2 emissions from RGGI-influenced EGUs based on modeling of the electricity sector and used the U.S. Environmental Protection Agency's (EPA's) Co-Benefits Risk Assessment (COBRA) to estimate changes in ambient levels of secondarily formed $PM_{2.5}$. The Environmental Benefits Mapping and Analysis Program (BenMAP) tool was used to estimate associated changes in health benefits due to changes in the ambient concentration of $PM_{2.5}$ in the nine then current RGGI states and in the adjacent states of New Jersey, Pennsylvania, Virginia, and West Virginia. BenMAP is a publicly available computer program supported by the U.S. EPA that can be used to estimate the number of air pollution-related illnesses and deaths and quantifies their economic value (U.S. EPA 2019). The program draws from a database that includes concentration–response (C-R) functions for a number of health outcomes attributable to different pollutants, population data, baseline health data, and cost of illness functions needed to quantify impacts (U.S. EPA 2019). The C-R functions included by default in the open-source program are focused largely on health outcomes for adults and do not currently include C-R functions or data for the children's health outcomes newly considered here.

Abt's 2017 assessment focused on avoided cases of premature adult deaths, heart attacks, acute bronchitis, asthma exacerbations, respiratory symptoms, hospitalizations, asthma emergency department visits, as well as productivity effects such as lost work days and days of minor restricted activity (Manion et al. 2017). These end points have traditionally been included in the U.S. EPA's regulatory analyses such as the *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter* (U.S. EPA 2012). The 2017 assessment found that between 2009 and 2014, emissions reductions from RGGI resulted in avoided health outcomes having an estimated value of between $3 billion and $8.3 billion (2015$).

Since Abt's original analysis, the evidence base has strengthened the relationship between $PM_{2.5}$ and additional health end points, particularly end points that affect children. Specifically, Perera et al. (2019) conducted a systematic review of epidemiological studies quantifying the impacts of changes in ambient $PM_{2.5}$ concentrations on health end points identified as having a causal or likely causal relationship with $PM_{2.5}$: preterm birth (PTB), term low birth weight (TLBW), autism spectrum disorder (ASD), and incidence of asthma. Based on this review, the authors selected odds ratios that could be used to develop C-R functions for each outcome in estimating the benefits of reducing $PM_{2.5}$ exposure.

The present analysis provides a more comprehensive evaluation of children's health benefits under RGGI by including these additional health end points. This involved incorporating C-R functions for the new health end points and data on baseline incidence of these end points into BenMAP. These inputs were used with emissions reductions and air quality modeling results from the 2017 RGGI analysis to estimate the impacts of RGGI on PTB, TLBW, ASD, and asthma between 2009 and 2014 in RGGI states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont) and adjacent non-RGGI states (Pennsylvania, the District of Columbia, New Jersey, Virginia, and West Virginia). Per-case monetary estimates (unit values) were incorporated into the expanded BenMAP based on a systematic review of the published literature on the cost of illness (Shea et al. 2020).

In addition, in order to more fully present the impacts/benefits in children, this report highlights the change in incidence of infant mortality, acute bronchitis, and respiratory symptoms in children included in the results of the 2017 analysis. However, these were not explicitly reported as occurring in children.

Methods

This section describes in detail the methods and data sources used to quantify and monetize the change in incidences of PTB, TLBW, ASD, and childhood asthma. Both RGGI states and adjacent non-RGGI states were included in the analysis.

Figure 1 summarizes the general analytic approach used in Abt's 2017 RGGI analysis (Manion et al. 2017). Step 1 involved estimating the change in NO_x and SO_2 emissions at the county-level based on electricity dispatch modeling conducted by the Analysis Group, an economics consulting firm, which included the change in electricity generation by EGUs under two scenarios: with RGGI and without RGGI. Abt then estimated the change in emissions due to the change in generation based on facility-specific emissions rates from U.S. EPA data. In Step 2, Abt used COBRA, a screening-level tool, which includes a reduced-form air quality model to estimate how changes in NO_x and SO_2 emissions would impact ambient concentrations of $PM_{2.5}$ in RGGI and neighboring states. The estimated incremental changes in NO_x and SO_2 emissions calculated in Step 1 were used to model changes in concentrations during individual years (2009–2014). Outputs from this model included annual changes in levels of ambient $PM_{2.5}$ in each county in RGGI and neighboring states and were the inputs for modeling the associated health impacts. Finally, in Step 3, Abt used the expanded BenMAP to estimate how changes in ambient $PM_{2.5}$ concentrations resulted in changes in health impacts in children.

The present analysis made no changes to Steps 1 and 2 from the 2017 analysis—we obtained annual average $PM_{2.5}$ concentration data from Abt Associates for the years 2009–2014. Rather, the present analysis added additional health end points to BenMAP and estimated how the modeled changes in $PM_{2.5}$ concentrations under RGGI (2009–2014) affected those additional end points. The remainder of this section discusses the specific inputs and steps taken in this analysis.

C-R Functions

C-R functions are estimates of the relationship between changes in ambient pollutant concentrations and incidences of specific health end points. These functions are derived from epidemiological studies that compare the change in incidences of specific health outcomes to, in this case, changes in ambient $PM_{2.5}$ concentrations.

Perera et al. (2019) conducted a systematic review of epidemiological studies, meta-analyses, and review articles to determine the current state of the science on the associations of ambient air pollutants, including $PM_{2.5}$, and children's health outcomes. Through this comprehensive review the authors identified four key meta-analyses that estimated the relationship between changes in $PM_{2.5}$ concentrations and changes in the incidence of each health end point (Table 1).

We used the results of Perera et al. (2019) to incorporate C-R functions for each end point into BenMAP. The C-R functions include a beta coefficient, which quantifies the impact on each health outcome per 1-unit change in $PM_{2.5}$ concentrations. We developed the beta coefficients shown in Table 1, based on the natural log of the odds ratio reported by the meta-analysis, divided by the reported exposure change (in micrograms per cubic meter), as is consistent with U.S. EPA practice (U.S. EPA 2012). The beta coefficients were combined with county-level data on

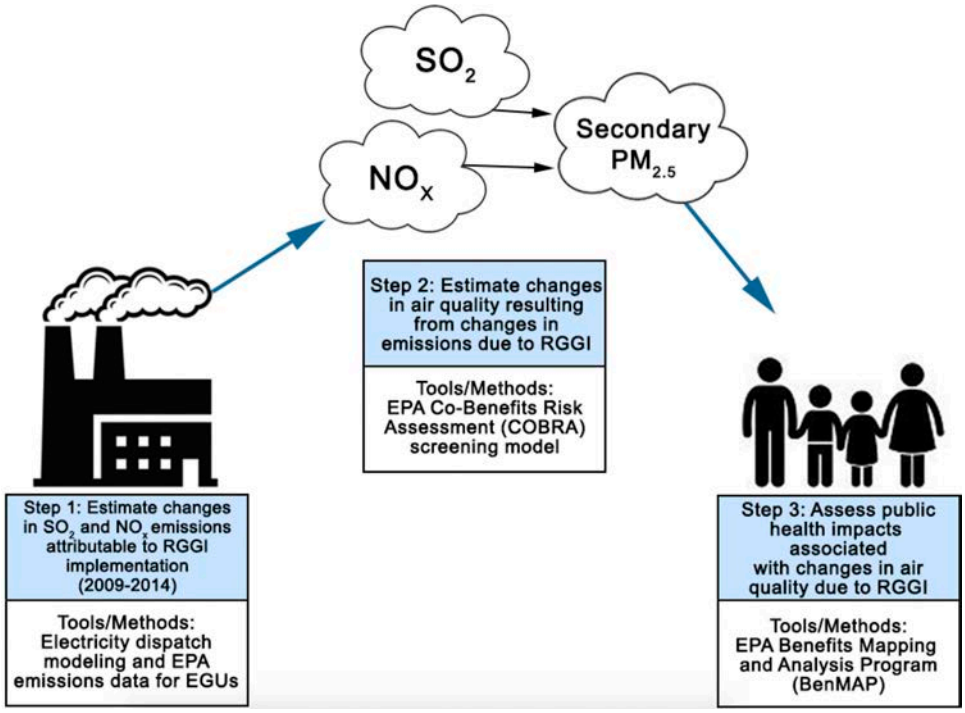

Figure 1. Overview of the analytic steps and tools. Source: Manion et al. 2017. Note: EGU, electric generating unit; EPA, Environmental Protection Agency; NO_x, nitrogen oxides; $PM_{2.5}$, particulate matter ≤2.5 μm in aerodynamic diameter; RGGI, U.S. Regional Greenhouse Gas Initiative; SO_2, sulfur dioxide.

population, baseline incidence, and the modeled change in county-level $PM_{2.5}$ concentrations to estimate the change in incidence of each health outcome in each county.

Population

The impact assessments require data on the affected age groups in the population. For this analysis, we used the county-level population by age group data loaded in BenMAP for each year of the analysis (2009–2014). These data were taken from the 2010 U.S. Census of Population and Housing models (developed by Woods and Poole 2011).

The C-R functions for PTB, low birth weight (LBW), and ASD reported in Perera et al. (2019) are based on maternal exposure during pregnancy. We applied the C-R functions to the population in Age Group 0 in BenMAP, which was used as a proxy for pregnant mothers. The C-R function for asthma incidence is based on the exposure of children under the age of 18 y. Accordingly, we applied this C-R function to populations in Age Groups 0–18.

Table 1. Meta-analyses for additional health end points associated with $PM_{2.5}$ identified by Perera et al. (2019).

Health end point	Study	Odds ratio	Exposure metric	Beta coefficient
PTB	Sun et al. 2015	1.13	Per 10-μg/m^3 increase	0.012
LBW	Sun et al. 2016	1.09	Per 10-μg/m^3 increase	0.009
ASD	Lam et al. 2016	2.32	Per 10-μg/m^3 increase	0.084
Asthma incidence	Khreis et al. 2017	1.03	Per 1-μg/m^3 increase	0.030

Note: Perera et al. (2019) conducted a systematic review to determine the current state of the science on the associations of ambient air pollutants, including $PM_{2.5}$, and children's health outcomes. The authors identified four key meta-analyses that estimated the relationship between $PM_{2.5}$ concentrations and the incidence of each health end point: PTB, LBW, ASD, and asthma. ASD, autism spectrum disorder; LBW, low birthweight; $PM_{2.5}$, particulate matter ≤2.5 μm in aerodynamic diameter; PTB, preterm birth.

Baseline Incidence

Baseline incidence rates for each end point were drawn from public data sources and the academic literature. County-level incidence rates of PTB and LBW were taken from the Centers for Disease Control and Prevention (CDC) WONDER database (CDC 2019), which contains extensive data on births, including gestational age and infant birth weight.

PTB is defined as a birth that occurs before the 37th week of pregnancy. The incidence of PTB was developed by dividing the number of births in each county occurring before the 37th week of pregnancy by the total number of births in each county. The county-level average incidence rate of PTB in RGGI and neighboring states was 13.4%. For comparison, the national average rate was 11.6%.

TLBW is defined in this analysis as a weight <2,500 g at birth when the infant was delivered on or after the 37th week of pregnancy (i.e., early to late term). This analysis does not include LBW in infants born before the 37th week of pregnancy to avoid double-counting the effects of PTB. The incidence of TLBW was calculated by dividing the number of full-term births in each county where the weight of the infant was <2,500 g by the total number of full-term births in each county. The county-level TLBW rate average was 3.2%. For comparison, the national TLBW rate average was 3.3%.

In the absence of county-level and complete state-level data, the asthma incidence rate for this analysis was taken from Winer et al. (2012), who estimated a national rate of 11.1 per 1,000 children ages 5–11 y from 2006–2008. This estimate was based on the Asthma Call-Back Survey, which was first implemented in 2006. Incident cases of asthma were defined as children diagnosed with asthma by a health care provider within 12 months prior to survey participation.

Because incidence rates were not directly available for ASD, we used prevalence as a proxy. In the absence of county-level and complete state-level data for prevalence, we selected the national prevalence rate of ASD for 2014 based on a CDC report (Zablotsky et al. 2015). We note that incidence is difficult to measure with rarer

chronic diseases such as autism. In addition, the disorder starts long before it is diagnosed, and the gap between initiation and diagnosis is influenced by many factors unrelated to risk (Hertz-Picciotto and Delwiche 2009). The rate used in this analysis was 14.7 per 1,000 children (Zablotsky et al. 2015).

Economic Valuation

The economic value of the change in incidences of each health end point was estimated using unit cost values from the literature (Shea et al. 2020). As described, those values were adjusted to 2015$ using a discount rate of 3% (Shea et al. 2020). Table 2 lists the values used in this analysis and the studies from which they were taken. The economic costs of each health end point were estimated by multiplying the change in incidences, as estimated by BenMAP, by the values in Table 2.

The values for asthma and ASD in Table 2 include high and low values. For asthma this is related to whether or not there is a persistence of the disorder into adulthood. For ASD this is related to whether there is an intellectual disability or not. For these end points, both the high and low values were used, and the results are reported as a range.

Results

This section describes the results of the analysis, including the estimated change in incidences of each health end point (the number of avoided cases) due to the emissions reductions associated with RGGI, as well as the economic valuation of those changes in incidences. Both the change in incidences and the economic valuation are summarized as the cumulative change between the year 2009 and the year 2014 (for both RGGI and neighboring states). The results are summarized separately for RGGI and neighboring states, and then totaled.

The results of this analysis are also compared with the results of the previous RGGI analysis (Manion et al. 2017), specifically the other health end points in children that were included in the previous analysis but not all explicitly labeled as occurring in children.

Change in Incidences

Table 3 shows the estimated change in incidence—the estimated number of avoided cases—of each health end point in RGGI and neighboring states between 2009 and 2014. Asthma had the largest change in incidence, at 537 cases avoided in the study area between the year 2009 and the year 2014. TLBW had the lowest change in incidence, at a total of 56 incidences avoided. This largely reflected that LBW had the smallest beta coefficient of the four end points (Table 1).

Table 3. Number of estimated avoided cases by health end point in RGGI and neighboring states (2009–2014).

Health end point	RGGI states	Neighboring states	Total
PTB	58	54	112
TLBW	29	27	56
ASD	50	48	98
Asthma	274	263	537

Note: RGGI states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Adjacent non-RGGI states include Pennsylvania, the District of Columbia, New Jersey, Virginia, and West Virginia. ASD, autism spectrum disorder; PTB, preterm birth; RGGI, U.S. Regional Greenhouse Gas Initiative; TLBW, term low birth weight.

Economic Valuation

Table 4 shows the results of the economic valuation of the change in incidences in RGGI and neighboring states between 2009 and 2014 for the newly incorporated health end points: ASD, asthma, TLBW, and PTB. As discussed above, both ASD and asthma have high and low estimates for the economic values of each end point. Results using both the high- and low-end estimates are shown here.

Although ASD was estimated to have the second-lowest number of avoided incidences compared with other health end points, it had by far the highest valuation per case, estimated at $1.8–3.1 million (Table 2). As a result, the economic valuation of the reduction in ASD incidences accounted for 84–89% of the total health benefits of the four health end points. Although asthma had a lower valuation per end point, it had the highest estimated change in incidence, leading it to have the second-highest value of the four health end points, at 6–13% of the total health benefits of those four end points. PTB and TLBW both had relatively lower per-unit economic values and lower estimated change in incidences. Therefore, the estimated economic valuation for those end points was comparatively smaller: 2–4% of the total benefits for PTB and <1% for TLBW.

Table 2. Per-case monetary estimates of each health end point (Shea et al. 2020).

Study basis	Health end point	Cost of illness definition	Unit value (2015$)
PTB			
Institute of Medicine Committee on Understanding Premature Birth and Assuring Healthy Outcomes 2007	Any PTB	Medical costs + special education costs + lost productivity costs, 3% discount rate (DR)	70,101
LBW			
Russell et al. 2007	LBW among those with slow growth/malnutrition	Initial hospital costs	15,560
ASD			
Buescher et al. 2014	ASDs with intellectual disability	Medical costs + non-medical expenditures + special education costs + lost productivity costs, 3% DR	3,109,096
	ASDs without intellectual disability	Medical costs + non-medical expenditures + special education costs + lost productivity costs, 3% DR	1,805,941
Asthma			
Nurmagambetov et al. 2018	Age 3 y onset, no persistence into adulthood	Medical costs + absentee costs, 3% DR	23,573
	Age 3 y onset, persistence into adulthood	Medical costs + absentee costs, 3% DR	91,954

Note: The values for asthma and ASD include high and low values. For asthma this is related to whether or not there is a persistence of the disorder into adulthood. For ASD this is related to whether there is an intellectual disability or not. For these end points, both the high and low per-case monetary estimate values were used, and the results are reported as a range. ASD, autism spectrum disorder; LBW, low birth weight; PTB, preterm birth.

Table 4. Estimated economic valuation (million 2015$) of change in incidence by health end point in RGGI and neighboring states (2009–2014).

	Low value			High value		
Health end point	RGGI states	Neighboring states	Total	RGGI states	Neighboring states	Total
ASD	87.3	83.7	171.0	150.2	144.1	294.4
Asthma	6.2	5.9	12.1	24.2	23.1	47.4
TLBW	0.4	0.4	0.8	0.4	0.4	0.8
PTB	3.9	3.6	7.5	3.9	3.6	7.5
Total	97.8	93.7	191.5	178.8	171.3	350.1

Note: The values for asthma and ASD include high and low values. For asthma this is related to whether or not there is a persistence of the disorder into adulthood. For ASD this is related to whether there is an intellectual disability or not. For these end points, both the high and low per-case monetary estimate values are used, and the results are reported as a range. ASD, autism spectrum disorder; PTB, preterm birth; RGGI, U.S. Regional Greenhouse Gas Initiative; TLBW, term low birth weight.

Comparison of Current Results to Estimates from the Previous (2017) Analysis

The 2017 Abt analysis of the health benefits of RGGI estimated total health benefits of between $3.0 billion and $8.3 billion between 2009 and 2014, using a 3% discount rate (Manion et al. 2017). This included an estimated 300–830 avoided premature adult mortalities, which accounted for the great majority of the monetized benefit.

The economic value of the health benefits of the four health end points in the present analysis were estimated at between $191 million and $350 million, or approximately 4–6% of the total benefits of the 2017 analysis, but considerably larger than the originally estimated impact from health outcomes excluding premature mortality.

Although the 2017 analysis did not specifically report benefits that accrue to adults and children separately, some of the health end points included in that analysis were focused on children. Specifically, the child-focused health end points included infant mortality, acute bronchitis, and respiratory symptoms. The numbers of estimated avoided incidences and economic valuation of those incidences are shown in Table 5. Note that the 2017 analysis included some health effects that applied to both children and adults, such as asthma emergency department visits and respiratory hospital admissions. Because it was not possible to separate out the impacts in children, those results are not discussed here.

As shown in Table 5, the economic value of the estimated health benefits to children from the 2017 analysis is dominated by avoided infant mortality. Although the estimated incidence was <1, the economic value per incidence is so high (approximately $11 million per incidence) that it vastly outweighs the economic value of the other health end points, which have per-incidence economic values of <$1,000 each.

The four health end points for children included in the 2017 analysis (Table 5) have a much lower total economic value than the four health end points in the present analysis (Table 4). The economic value of the benefits to children included in the 2017 analysis are approximately 2–4% the size of the value of the benefits to children newly included in the present analysis.

The total health benefits to children from RGGI between 2009 and 2014, including all eight health end points (both those in the 2017 analysis and the present analysis), were estimated at $199.6–358.2 million.

Table 5. Estimated health benefits for children due to RGGI (2009–2014) from the previous Abt Associates analysis [RGGI and neighboring states (Manion et al. 2017)].

Health end point	Avoided incidences	Economic value (million 2015$)
Acute bronchitis	510	0.30
Infant mortality[a]	<1	7.30
Lower respiratory symptoms	6,500	0.17
Upper respiratory symptoms	9,300	0.37
Total[b]	16,310	8.10

Note: BenMAP, Benefits Mapping and Analysis Program; RGGI, U.S. Regional Greenhouse Gas Initiative.
[a]The 2017 analysis estimated <1 avoided infant mortality due to RGGI. It is important to note that the C-R functions in BenMAP estimate actual health outcomes based on the change in risk of an outcome. Therefore, estimating <1 avoided infant mortality means that RGGI reduced the risk to infants by a relatively small, although not negligible, amount. Nevertheless, this reduced risk still has a very high economic value relative to the other health outcomes.
[b]Totals may not sum due to rounding.

Distributional Analysis of Benefits across Counties

The map in Figure 2 shows considerable variation across RGGI and neighboring counties in the distribution of economic benefits from the cumulative avoided child health outcomes: PTB, TLBW, ASD, asthma, infant mortality, acute bronchitis, lower respiratory symptoms, and upper respiratory symptoms.

Figure 3 maps the spatial distribution of reductions in average annual $PM_{2.5}$ concentrations between 2009 and 2014 at the county level attributable to RGGI during its first and second compliance periods. These results show substantial air quality benefits, particularly in counties downwind of Maryland's power plants regulated under RGGI. In addition, counties in New Jersey and Pennsylvania, both currently non-RGGI states, experienced significant air quality improvements attributable to emission reductions in neighboring RGGI states.

It is important to note that estimates of reductions in $PM_{2.5}$ concentration represented in Figure 3 account only for secondary $PM_{2.5}$ formed by chemical reactions of NO_x and SO_2. This analysis does not account for impacts of directly emitted $PM_{2.5}$. Nor does it account for the health effects from other pollutants such as ozone (O_3) or nitrogen dioxide (NO_2), thereby underestimating the health benefits under RGGI.

Discussion

Over the past decade, RGGI has driven significant emission reductions from the electric power sector. The program's initial goal was to reduce annual power sector CO_2 emissions by 45% below 2005 levels by 2020. Their 2030 goal was to reduce emissions by an additional 30% (Center for Climate and Energy Solutions 2019). According to a recent report by RGGI, by 2017, participating states had reduced CO_2 emissions from the power sector by more than 50% since 2005 while maintaining steady regional gross domestic product growth (RGGI Inc. 2019b), suggesting that RGGI states have exceeded their initial goal and are on track to meet their 2030 goal. Additional findings from a 2019 assessment (Acadia Center 2019) indicate that since 2008 (1 y prior to the program's launch), RGGI states' emissions from the electric power sector decreased from 133 million short tons of CO_2 to 70 million; these reductions exceeded those of the rest of the country by 90% (Acadia Center 2019). Although RGGI has not been the single driver behind the northeastern region's decarbonization in the electric power sector, a previous analysis (Murray and Maniloff 2015) has suggested that the program has

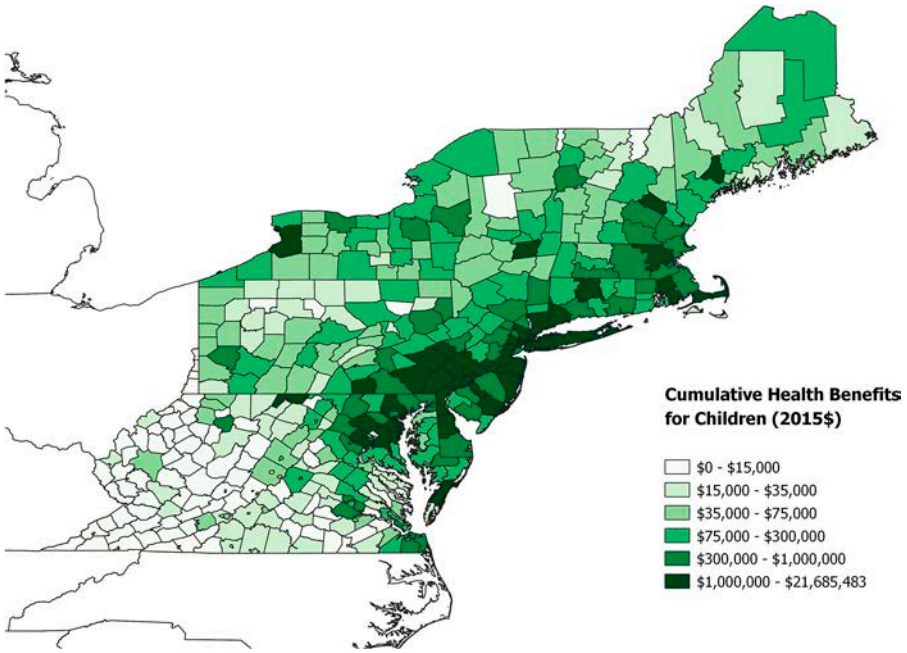

Figure 2. Economic benefits of avoided cases of child health outcomes attributable to RGGI by county, 2009 to 2014 (low value, 2015$). Note: RGGI, U.S. Regional Greenhouse Gas Initiative.

been a significant factor in the reduction of power plant emissions. Simulations from that analysis also suggested that emissions would have been approximately 24% higher in the region and 1.4% higher in the United States in 2012 without the program's implementation in 2009 (Murray and Maniloff 2015).

The results of our analysis of RGGI's co-benefits from the reduction in air pollution indicate that RGGI has provided substantial child health benefits beyond those considered in the 2017 analysis. Moreover, those health benefits have significant estimated economic value. The previous analysis found large total health benefits with a total economic value of $3.0–8.3 billion; nearly all of those benefits were due to avoided adult mortality (Manion et al. 2017). The benefits from health end points specific to children included in the 2017 analysis (infant mortality, acute bronchitis, and other respiratory symptoms) were estimated at $8.1 million, accounting for a very small fraction (0.09–0.27%) of the total estimated health benefits. The four additional health end points considered here—PTB, TLBW, ASD, and asthma—have a much larger combined economic value ($191–350 million) than those previously considered and amount to 4–6% of the total adult and child benefits from the 2017 analysis. This is likely to be an underestimate, as discussed below. Of the four additional health end points, asthma had the most significant change in incidence (number of avoided cases) between 2009 and 2014. This is expected, given that the C-R function used to estimate the incidence of asthma was applicable to all children ages 0–18 y, while the C-R functions for the other health end points were applied only to infants (age 0 y). As a result, there is a larger population of children for whom the analysis estimated impacts on the incidence of asthma.

Although a modest contribution to the total avoided costs, estimates from the present study are 20–40 times greater than the value of the avoided child outcomes in the 2017 analysis (Manion et al. 2017). The estimated total economic benefit from these avoided cases attributed to RGGI between 2009 and 2014, including the combined eight health end points considered in the 2017 analysis and the present analysis, was $199.6–358.2 million.

Not only is this a substantial economic benefit, but it is likely an underestimate of the true benefit because the adverse outcomes in children associated with $PM_{2.5}$ not only have immediate heath impacts but can also have serious consequences for their future health, well-being, and ability to contribute to society. These long-term health or lifelong consequences are not adequately considered in most of the outcome valuations used in this analysis.

In addition, it is important to note that the per-case estimates used in our calculations of avoided costs are likely underestimates for a few reasons, including the reliance on the cost of illness (COI) (Shea et al. 2020). For instance, as the U.S. EPA *Guidelines for Preparing Economic Analyses* notes, the COI method for developing per-case estimates typically does not attempt to quantify a loss in utility from pain and suffering (U.S. EPA 2010). Given that these costs are often omitted from COI estimates, the value of an individual's willingness to pay to avoid a lifetime of an illness like asthma may be significantly larger than the COI value. Furthermore, potential long-term costs to children or parents were not generally considered in the per-case monetary estimates used in this study (Shea et al. 2020). Examples are a child's cognitive disability associated with PTB and the impact on parents' employment behaviors, affecting their household income (Petrou et al. 2001).

A further factor in potentially significant underestimation of benefits is that both the 2017 and the present analyses include only emission reductions of NO_x and SO_2. Although secondary $PM_{2.5}$ accounts for the majority of $PM_{2.5}$ resulting from power plant emissions (NARSTO 2004), the analysis did not consider impacts from directly emitted $PM_{2.5}$. Nor were the health benefits of reductions in O_3 precursors, NO_2, and climate-altering greenhouse gases factored into this analysis. For these reasons, the results are conservative.

The health benefits from RGGI are not likely to be evenly distributed geographically, with some populations receiving higher health benefits than others. This analysis (like Manion et al. 2017) estimated the geographic distribution of health benefits by county but did not attempt to estimate disparities in health benefits by differences in socioeconomic status or ethnicity/race. This is because air quality results used in this analysis (and the previous 2017 analysis) are at the county level, and socioeconomic

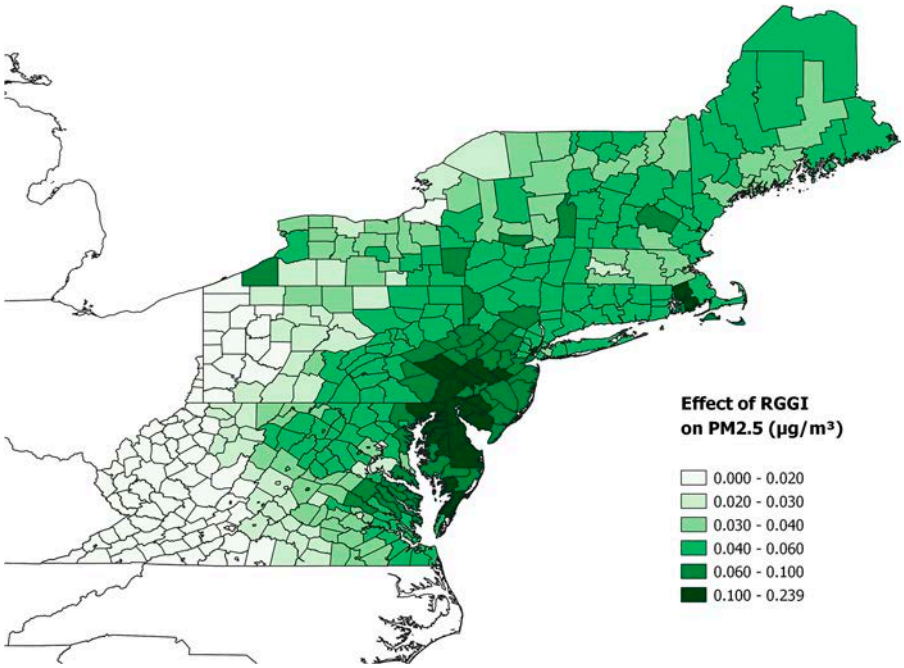

Figure 3. Reductions in average annual $PM_{2.5}$ concentrations by county attributable to RGGI (2009–2014) Source: Abt Associates 2017. Estimates of reductions in $PM_{2.5}$ concentration account only for secondary $PM_{2.5}$ formed by chemical reactions of NO_x and SO_2. This analysis does not account for impacts of directly emitted $PM_{2.5}$. Nor does it account for the health effects from other pollutants such as O_3 or NO_2, thereby underestimating health benefits under RGGI. Note: NO_x, nitrogen oxides; NO_2, nitrogen dioxide; O_3, ozone; $PM_{2.5}$, particulate matter ≤2.5 µm in aerodynamic diameter; RGGI, U.S. Regional Greenhouse Gas Initiative; SO_2, sulfur dioxide.

status and distribution of population by ethnicity/race can vary widely within counties (Sommeiller et al. 2016).

Exploratory assessment of the distributional impacts of the health benefits and associated economic benefits at the county level showed significant variation in benefits across counties, as demonstrated in Figure 2. The monetized benefits are a function of the change in air quality and the total population affected. As a result, more densely populated areas would be expected to have higher benefits because there is a larger at-risk population (more pregnant women and children) breathing cleaner air. This is likely occurring in densely populated counties across New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, and New Jersey. Reductions in average annual $PM_{2.5}$ concentrations between 2009 and 2014 under RGGI, as shown in Figure 3, suggest substantial air quality benefits.

A comparison of the two maps (Figures 2 and 3) gives a sense of the magnitude of the air quality changes experienced in each county relative to their corresponding health benefits. Similar to the economic benefits map (Figure 2), the map of reductions in $PM_{2.5}$ concentrations (Figure 3) shows considerable variation across counties. In most counties, the distribution of economic benefits corresponds with reductions in levels of $PM_{2.5}$; highlighting the direct benefit from emission reductions. On the other hand, as shown in Figure 3, some counties—for example, in Massachusetts, Connecticut, and Rhode Island—experienced disproportionately high estimated health and economic benefits in relation to their low level emission reductions; indicating that even slight reductions in $PM_{2.5}$ emissions resulted in considerable benefit.

Because of the scale of analysis, we were not able to meaningfully examine whether benefits were shared equitably across socioeconomic strata and different racial/ethnic populations. This is a major concern with respect to environmental justice given that it is the less affluent communities and communities of color that have borne the brunt of fossil fuel–related pollution and climate change impacts (Morello-Frosch et al. 2011). Although regional cap and trade policies like RGGI may be effective in reducing greenhouse gases and their co-pollutants on a regional scale, they may not maximize public health benefits or adequately address existing environmental justice issues. A more granular analysis (e.g., at the census tract or neighborhood level) is necessary to better understand finer-grained changes in air quality and the true distribution of health benefits by population density, socioeconomic status, and ethnicity/race. Such a comprehensive assessment could provide an opportunity to evaluate whether alternative programs could achieve the same greenhouse gas mitigation goals while also redressing environmental injustice.

As noted by Manion et al. (2017), the benefits associated with reducing emissions of the major greenhouse gas, CO_2, are outside of the scope of this study. Thus, the analysis does not cover the many health benefits of mitigating climate change, such as fewer heat-related illnesses or cases of vector-borne disease to which children are especially vulnerable. In addition, benefits to ecosystems and natural resources that support human livelihood are not captured in this analysis.

Because the epidemiologic evidence on the association between $PM_{2.5}$ and child intelligence quotient (IQ) is suggestive only (Chiu et al. 2016; Harris et al. 2015), we were not able to consider the potentially large benefit of RGGI in terms of improvement in child IQ. Decreased IQ in boys has been associated with gestational exposure to higher $PM_{2.5}$ levels (Chiu et al. 2016). Prenatal exposure to polycyclic aromatic hydrocarbons, a component of $PM_{2.5}$, has also been associated with lower child IQ (Perera et al. 2009). In addition, the association between PTB and IQ reduction, previously identified in the literature (for review, see Allotey et al. 2018; Bhutta et al. 2002; Kerr-Wilson et al. 2012), is not accounted for—thereby underestimating the impacts of PTB. A meta-analysis by Kerr-Wilson et al. (2012) estimated a decrement of 11.94 (95% confidence interval: 10.47, 13.42) IQ points among preterm children compared with children born at term. The loss of 1 IQ point has been estimated to result

in a $17,815 loss of lifetime earnings per child (Gould 2009). Therefore, preventing the contribution of $PM_{2.5}$ exposure to PTB could have substantial economic benefits.

We note that the evidence with respect to $PM_{2.5}$ and ASD support a likely causal association. A highly cited systematic review and meta-analysis by Lam et al. (2016) has identified a number of studies on air pollution exposure during developmental periods that have found associations with ASD. The analysis by Lam et al. (2016) included 23 human studies published between 2006 and 2015, 9 of which assessed particulate matter (including PM_{10} and $PM_{2.5}$). The review found evidence for associations between prenatal exposure to $PM_{2.5}$ and ASD (Lam et al. 2016). Additional studies have been published since this review that have found positive associations between prenatal and/or early life $PM_{2.5}$ exposure and ASD (Kaufman et al. 2019; Jo et al. 2019; McGuinn et al. 2020).

Despite its limitations, the present analysis provides evidence of the importance of comprehensive assessments of child health benefits in analyses of the benefits of climate mitigation and air pollution emissions reduction policies. With respect to the distributional impacts, additional research is needed to refine and extend the overall benefits estimates provided here. Nevertheless, this analysis has estimated substantial benefits of RGGI for children's health.

Conclusion

Findings from the present assessment indicate that RGGI has provided considerable child health benefits to participating and neighboring states beyond those conventionally considered. Moreover, those health benefits are estimated to have significant economic value. Our assessment of the projected health co-benefits to children under RGGI can provide valuable support for the design and implementation of future programs to mitigate climate change targeting other sectors, including the transportation sector. Findings from this assessment also should encourage other states to join the program or initiate similar strategies of their own. In addition, our newly incorporated C-R functions and economic values for children's health end points into BenMAP are important additions to the existing program, which can be used widely. In this sense, the present study is generalizable and the methods can be used to quantify children's health and economic benefits under other climate change mitigation, air pollution control, and environmental programs.

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Attachment 50

Regional Greenhouse Gas Initiative, Inc.

Scope of Work in Support of Virginia Department of Environmental Quality Implementation of the Virginia Carbon Dioxide (CO_2) Budget Trading Program

Regional Greenhouse Gas Initiative, Inc. ("RGGI, Inc.") will provide program implementation, administration and development services, as outlined in this Scope of Work, to the Virginia Department of Environmental Quality ("Department") to support the Commonwealth of Virginia's ("Commonwealth") participation in the Regional Greenhouse Gas Initiative ("RGGI") and the implementation of regulations for the Virginia CO_2 Budget Trading Program ("Program"). RGGI, Inc., a non-profit organization incorporated in the State of Delaware, was formed expressly to provide technical implementation and program development support services to the states participating in RGGI ("participating states").

Overview

As described more fully herein, RGGI, Inc. will provide services to support implementation of the Program in the following seven areas:

I. Operation of the RGGI CO2 Allowance Tracking System (RGGI COATS), for use by the Department in administering the Program in coordination with counterpart programs in other participating states.

II. Operation of a regional allowance auction platform, for use by the Department in administering the Program in coordination with counterpart programs in other participating states.

III. Development of model offset consistency applications and model offset monitoring and verification submittal forms, suitable for customization by the Department for use in administering the offset components of the Program.

IV. Development of generic and category-specific guidance documents detailing the requirements for offset projects under the RGGI Model Rule, suitable for customization by the Department for use in administering the offset components of the Program.

V. Maintenance and operation of an accreditation process and provide materials for the accreditation of independent verifiers of offset projects, suitable for customization by the Department for use in accrediting independent offset verifiers.

VI. Market monitoring services for the monitoring of both allowance auction conduct and outcomes and the secondary allowance market.

VII. Provision of program development support services on an as-requested basis, including, but not limited to, evaluation of additional offset categories and the development of technical and policy recommendations related to specific Program elements for evaluation and consideration by the Department.

I. No Policy Role or Regulatory Authority

RGGI, Inc.'s activities under this Agreement shall not include any policy role or decision-making authority regarding policy matters of the Commonwealth, including, without limitation, the Commonwealth's positions in response to federal policies, the Commonwealth's decisions regarding any future changes to the Program, and the Commonwealth's interaction with participating states or other states that may be considering becoming a participant in RGGI. RGGI, Inc. shall also have no regulatory authority under this Agreement, including, without limitation, authority to enforce the Program and authority to interpret any provisions of the Program. All such policy roles, decision-making authority, and regulatory authority shall remain with the Commonwealth under this Agreement.

I. RGGI CO2 Allowance Tracking System (RGGI COATS)

RGGI, Inc. shall provide services to support allowance tracking for the Program through RGGI COATS. Such services shall include annual program implementation and support. RGGI COATS facilitates market participation by supporting:

- The origination, allocation, award, and transfer of CO_2 allowances.
- The certification and providing of CO2 allowances for compliance-related tasks; and,
- The registration and submittal of applications and reports for offset projects.

II. RGGI, Inc. shall provide on-going implementation and operational support for RGGI COATS, including the tasks outlined below.

II-A. Allowance Program Management

RGGI, Inc. shall provide implementation support to the Department for all Program activities relating to CO2 budget source account management, allowance allocations to compliance and general accounts, and allowance transfers for both general and compliance accounts. This shall include all activities necessary to support the assignment of allowances to appropriate accounts following the successful completion and Department approval of all allowance auctions, as well as the population of user accounts after Department award of offset allowances.

II-B. Emissions Data Management and Analysis

RGGI, Inc. shall perform all data management and quality assurance tasks necessary to ensure the availability of annual CO2 emissions data from all affected units. RGGI, Inc. shall prepare and send communications to the authorized account representatives for budget sources relating to emissions values. RGGI, Inc. shall work with the Department to identify and resolve any issues relating to the submission of emissions data, and the accuracy and

completeness of the data. To the extent requested by the Department, RGGI, Inc. shall contact authorized account representatives directly to resolve any outstanding issues. RGGI, Inc. shall document all issues, their resolution, and all contacts with authorized account representatives.

II-C. Allowance Reconciliation (True-up)

RGGI, Inc. shall assist the Department with compliance assessments for the Program. RGGI COATS shall support the entry of compliance certifications required by the Program and the identification of allowances to be deducted during the compliance process. Assessments shall also factor in appropriate offset limits as a function of a source's reported emissions. RGGI, Inc. shall prepare draft and final compliance reports and will provide information to the Department regarding possible non-compliance.

II-D. User Technical Support

RGGI, Inc. shall provide technical support to industry, the Department, and public users for RGGI COATS. RGGI, Inc. shall record all technical support requests, inquiries, or other occurrences in a log that identifies the nature of the request or events, requestor, respondent, response provided, date(s) and time(s) of response, and amount of time expended on the request and response. Records shall be provided to the Department on a periodic basis, or on demand, as requested.

As necessary, RGGI, Inc. shall provide assessments and recommendations relating to performance of RGGI COATS based on the technical support levels and user feedback. RGGI, Inc. shall not be responsible for interpretation of the Department's regulations, and/or interpretation of actions taken by the Department in enforcement of those regulations.

II-E. System and Database Support

RGGI, Inc. shall be responsible for all aspects of RGGI COATS maintenance and database support and management. This shall include on-going database quality assurance activities, management of all user accounts and security, coordination and monitoring of the Application Service Provider support activities, database, security and application performance, and all other tasks designed to ensure high system availability and performance. RGGI, Inc. shall provide reports to the Department on all routine activities and on any events or technical issues that will affect the operation or performance of the system. RGGI, Inc. shall oversee all data backup and audit procedures to ensure the on-going integrity of the data.

III. Allowance Auction Platform

RGGI, Inc. shall implement and administer a process and platform for the auctioning of allowances under the Program. RGGI, Inc. shall provide auction services in three general areas: pre-auction, auction implementation, and post-auction.

Pre-auction Services

Consultation

RGGI, Inc. shall work with Department staff to maintain the draft standard allowance purchase and sales agreement that is comparable to those developed by other participating states. In addition, RGGI, Inc. may be asked to provide general consultation to the Department on auction design. This may include consultation on auction activity procedures and auction closing procedures.

Auction Notices

RGGI, Inc., in consultation with the Department and subject to its approval, shall create documents and associated information necessary to inform auction participants about details of each auction. Each notice of auction shall provide a specific description of the auction format that will be used, the quantities of allowances to be auctioned, and all applicable participation requirements, consistent with the participating states' rules. Such information shall be made available on the RGGI, Inc. auction website, which can be found through the RGGI, Inc. website, https://www.rggi.org. RGGI, Inc. shall prepare and host an auction participant training presentation for public viewing prior to each auction, as well as receive and respond to written questions submitted by conference participants.

Participant Qualification

RGGI, Inc., in consultation with the Department, shall ensure that all qualified participants have completed the applicable qualification application materials and documents prior to participation in any auction. RGGI, Inc. shall manage, under the direction of the Department, the application process, including receiving and reviewing each qualification application to determine completeness and accuracy of the information submitted. RGGI, Inc. shall be responsible for collecting and managing all auction financial security submissions and/or escrow accounts for the Department. RGGI, Inc., in consultation with the Department, shall be responsible for notifying bidders of their qualification status and maintaining a database of all qualified bidders.

Auction Documentation and Training

To prepare for each auction, RGGI, Inc. shall, subject to the Department's approval, create and distribute auction materials, such as participation instructions, final auction procedures and manuals, as well as the distribution of user codes and passwords to qualified auction participants. In addition, RGGI, Inc. shall be responsible for training auction participants in the use of the auction software platform.

III-B. Auction Implementation Services

Auction Platform

RGGI, Inc. shall maintain and administer an online auction platform for the auctioning of allowances under the Program capable of accommodating an auction in the following formats:

- A sealed bid, uniform price auction
- A sealed bid, discriminatory-price auction
- An ascending price, multiple-round auction
- A descending price, multiple-round auction

Furthermore, the online auction platform shall be capable of managing allowance purchase limits based on specifications provided by the Department. In addition, the auction platform shall be capable of tracking bidding activity and must provide for audit level documentation of such activity, in accordance with auction monitoring protocols that are established by RGGI, Inc. in consultation with the Department and subject to its approval.

IV-C. Post-auction Services

RGGI, Inc. shall arrange for and facilitate the transfer of funds from successful bidders to an account designated by the Department and arrange for the return of financial security to bidders. RGGI, Inc. shall also be responsible for coordinating the operation of RGGI COATS for the transfer of allowances, at the direction of the Department, to the compliance or general accounts of the winning bidders. RGGI, Inc. shall also be required to: (1) work with any independent third party hired by the Department to verify the results of the auction, including potential redress; (2) if directed by the Department, post appropriate information about auction results; and (3) work with the Department to use on-going auction experience to improve subsequent auctions.

RGGI, Inc. shall administer a bank account for holding financial security from bidders. RGGI, Inc. shall impose access security controls on such account to the satisfaction of the Department. RGGI, Inc. shall transfer the proceeds from the sale of allowances at auction to an account to be designated by the Department using an ACH transaction no later than one business day following the transfer of allowances to winning bidders.

IV. Model Offset Consistency Applications and Monitoring and Submittal Documents

RGGI, Inc. shall provide model offset consistency applications and model monitoring and verification report submittal forms for each eligible offset category in the RGGI Model Rule, suitable for customization by the Department. These model application and submission materials will facilitate monitoring of the Department's offset project approval process by market observers and other participating states. All materials developed by RGGI, Inc. shall be consistent with the Model Rule criteria.

V. Model Offset Guidance Documents

RGGI, Inc. shall provide model generic and category-specific offset project guidance documents suitable for customization by the Department. This model guidance shall be detailed and easily understandable by project sponsors (including small businesses or other parties that may lack experience in carbon offset markets) and by Department staff.

The model guidance documents developed by RGGI, Inc. shall cover submittal requirements and the evaluation of specific offset projects against the Model Rule requirements. The model guidance documents shall also explain the intent and letter of the offset project provisions in the RGGI Model Rule, address any ambiguities in the Model Rule provisions, and clarify how they apply to specific types of projects. Any interpretive material shall be consistent with the Model Rule criteria and shall be reviewed by the Department and the participating states.

RGGI, Inc. shall also identify project scenarios that address questions that are likely to arise in the course of the offset application and approval processes, based on the expertise of RGGI, Inc. staff, other offset program experience, and communications with the Department and the participating states.

VI. Accreditation Process and Training Program for Independent Verifiers of Offset Projects

RGGI, Inc. shall maintain a process for the accreditation of independent offset project verifiers and a related training program, consistent with the requirements of the Model Rule, which can be customized and used by the Department in accrediting independent offset verifiers.

RGGI, Inc. shall also provide supporting materials for independent verifiers, consistent with the requirements of the RGGI Model Rule, which can be customized and used by the Department, and which explain:

- The process for the accreditation of independent verifiers, including the review of candidate verifier qualifications.
- The process for evaluating candidate verifier conflicts-of-interest; and
- Application materials for accreditation.

RGGI, Inc. shall also provide materials that can be customized for use by the Department to support on-going Department review of an accredited verifier's potential conflicts-of-interest, including the following:

- Submittal forms for accredited verifier disclosure of potential conflicts-of-interest, to be reviewed by the Department prior to the verifier engaging in work with an offset project sponsor; and

- Guidance materials to support Department staff review of accredited verifier potential conflicts-of-interest.

These materials shall provide a review of existing greenhouse gas independent verifier accreditation standards and processes used by other voluntary and mandatory greenhouse gas management or regulatory programs, and incorporate, if appropriate, elements of these into the materials developed for the Department. RGGI, Inc. shall provide a brief evaluation of the standards and processes reviewed.

VII. Market Monitoring

RGGI, Inc. shall provide market monitoring services in three general areas: monitoring and auditing of allowance auctions, monitoring of relevant secondary allowance market activity, and provision of consultative services addressing market monitoring.

VII-A. Monitoring and Auditing of RGGI Allowance Auctions

RGGI, Inc. shall provide professional monitoring of all RGGI regional allowance auctions, some of which may involve a subset of the RGGI participating states and may or may not include allowances submitted for auction by the Department. RGGI, Inc. will use and develop, as appropriate, data collection methods, metrics, and analytic techniques for monitoring auction performance and thresholds for identifying any collusion, market power, and/or market manipulation that may impact the efficiency and performance of the RGGI auctions.

VII-B. Monitoring of Secondary Market Behavior

RGGI, Inc. shall monitor all relevant publicly available data and indicators of market behavior (available through both public and private sources) in the secondary allowance market that may be expected to significantly impact the performance of RGGI auctions and/or the secondary allowance market.

VII-C. Consultative Services

RGGI, Inc. shall provide expert advice to the Department regarding how any aspects of the auction process should be altered to improve the performance and efficiency of the RGGI auctions and shall ensure the functioning of fair and competitive auctions and a secondary allowance market.

VIII. Program Evaluation and Development Support

RGGI, Inc. shall provide program evaluation and development support to the Department, as requested, to facilitate Department consideration of potential modifications to and/or expansion of the Program.

IX. Effective Date, Project Term

The Effective Date of this Agreement shall be the date upon which it is signed by the Agency Director. The parties recognize and agree that the Commonwealth of Virginia will not be a Participating State as defined in the RGGI, Inc. By-Laws until January 1, 2021. Between the Effective Date and January 1, 2021, it is agreed that RGGI, Inc. staff will work with appropriate members of the Department to prepare for the Commonwealth's participation in RGGI beginning on January 1, 2021, as outlined in this Agreement.

The initial term of this Agreement shall be from February 1, 2021 to December 31, 2023.

The initial term of this Agreement may be extended for up to two (2) additional three (3) year terms, or any portion thereof, by mutual written agreement of the Department and RGGI, Inc. in accordance with the procedures set forth in this Agreement.

X. Budget/Payment

The Department shall pay to RGGI, Inc. an amount equal to the State's proportionate share of RGGI, Inc.'s annual operating budget, which shall be calculated based on the State's proportionate share of the regional CO2 allowance budget.

For services rendered for the initial term, based upon RGGI, Inc.'s projected annual operating budget for calendar year 2021, the Department shall pay RGGI, Inc. an amount not to exceed $592,920 ("2021 payment"), for the services set forth in the table below. The Department authorizes RGGI, Inc. to retain a quarter (25%) of this payment "off the top" of the Commonwealth's proceeds from the sale of allowances in each of the quarterly auctions in calendar year 2021.

General Service Category	Percentage of Funding	Approximate Amount
Allowance Tracking	20%	$118,584
Auctions	30%	$177,876
Market Monitoring	15%	$88,938
Technical Modeling	15%	$88,938
Program Management	20%	$118,584
TOTAL	**100%**	**$592,920**

For services rendered for any subsequent calendar year or portion thereof ("subject year") of this Agreement, RGGI, Inc. shall submit to the Department, by December 15 of the year preceding the subject year, a request for payment of its estimated operating costs for the subject year and the State's proportionate share (itemized as set forth above). Operating costs include staff and overhead costs, costs incurred in performance of the services and deliverables set forth in the Scope of Work and the Department's contribution to support services that may be provided jointly to the Department and agencies in other RGGI participating states.

XI. Reporting

RGGI, Inc. shall designate a Project Manager, who shall be the one point of contact with the Department. The Project Manager shall be responsible for monitoring and ensuring progress for all tasks and subtasks, and for ensuring timely delivery of all services and deliverables outlined in this Scope of Work. The RGGI, Inc. Project Manager shall be responsible for all project reporting to the Department.

The following reporting obligations shall begin February 1, 2021.

By the 15th day of January, April, July, and October of each year during the Project Term, RGGI, Inc. shall provide the Department with a detailed report of the activities undertaken by RGGI, Inc. and its subcontractors to meet its responsibilities under this Agreement during the preceding calendar quarter, including, without limitation, quarterly status reports on RGGI COATS; the auction program; offset program support; market monitoring findings; quarterly budget reports, including any audit reports; the status of progress in providing the deliverables specified in the Scope of Work, including identification of all completed/not completed work during the preceding three-month period; and description of any problems encountered by RGGI, Inc. and their actual or proposed resolution.

At least once in each calendar quarter, RGGI, Inc. shall also submit to the Department a report of its expenditures for operating costs covering each full month in the preceding completed quarter. Such report shall reconcile the actual expenses for operating costs against either the 2020 payment or estimates contained in a request for payment for a subject year, as applicable, and shall provide a net credit to be applied against subsequent requests for payment of operating costs to the extent that actual expenses were less than the estimates. For a subject year, if actual expenses are greater than the estimates contained in a request for payment, the balance shall be itemized as such and applied to subsequent requests for payment of operating costs. Any remaining credit at the end of the term of this Agreement shall be returned to the Department by RGGI, Inc. within 30 days of expiration of this Agreement. Any remaining costs at the end of the Project Term shall be paid by the Department to RGGI, Inc. within 60 days of receipt of a final request for payment in accordance with the Prompt Payment Act, N.J.S.A. 52:32-32, et seq., provided that the listed operating costs are in accordance with this Agreement.

Within 30 days after the end of the term of this Agreement, RGGI, Inc. shall prepare and submit a draft final report that provides a description and summary of all major work tasks and submitted deliverables. The draft final report shall be revised to address all Department comments within 60 days of receipt by RGGI, Inc., and RGGI, Inc. shall submit a final report addressing all such comments.

XII. Services, Deliverables

RGGI, Inc.'s performance shall include, and the Department shall cooperate in, all tasks necessary to set up or otherwise "onboard" the Department and its facilities. All services provided by RGGI Inc. in support of the Department's implementation of the Program shall be performed in accordance with and meet all applicable Program requirements.

In any area where services are requested or deliverables will be provided, all deliverables shall be presented to the Department in draft form for review and ultimate approval by the Department. All documents generated or accepted in performance of this Agreement shall be confidential and shall not be released to anyone without prior authorization by the Department, unless directed by a court of competent jurisdiction. This confidentiality provision shall govern this Agreement and shall survive the termination or expiration of this Agreement.

XIII. Notices

All notices, approvals and other communications which may or are required to be given by either party to the other shall be in writing and shall be transmitted, by certified or registered United States mail, return receipt requested, expedited delivery service, or email, return receipt requested, to the party's representatives identified below:

For the Department:

David K. Paylor, Director, Virginia Department of Environmental Quality
P.O. Box 1105
Richmond, VA 23218
Email: David.Paylor@deq.virginia.gov

For RGGI, Inc.:

Andrew J. McKeon, Executive Director
90 Church St.
New York, NY 10007-2919
Email: andrew.mckeon@rggi.org

The parties may, from time to time, specify any new or different address in the United States as their address for purpose of receiving notice by giving fifteen (15) days written notice to the other party. The parties may, from time to time, designate in writing new or different individuals as their respective representatives for the purpose of receiving notices under this Agreement. Additional individuals may be designated in writing by the parties for purposes of implementation, administration, and billing.

SIGNED:

Regional Greenhouse Gas Initiative, Inc. (RGGI, Inc.)

By: Andrew J McKeon
(signature)

Andrew McKeon
(print name)

Executive Director, RGGI, Inc.
(print title)

Date:

SIGNED:

Virginia Department of Environmental Quality

By: David K Paylor
(signature)

DAVID K. PAYLOR
(print name)

Director
(print title)

Date: 2/8/2021

Attachment 51

RGGI Inc.

Auction 59
State Proceeds and Allowances

State	Auction 59 Allowances Sold	Cumulative Allowances Sold (Auctions 1-59)	Auction 59 Proceeds	Cumulative Proceeds (Auctions 1-59)
Connecticut	905,205	79,507,550	$11,315,062.50	$348,031,056.24
Delaware	659,746	46,291,765	$8,246,825.00	$223,275,639.35
Maine	472,803	39,601,657	$5,910,037.50	$176,031,057.84
Maryland	2,596,685	243,693,704	$32,458,562.50	$1,039,010,597.40
Massachusetts	2,228,337	199,294,177	$27,854,212.50	$865,971,579.24
New Hampshire	830,919	56,202,007	$10,386,487.50	$262,778,505.24
New Jersey	3,009,395	89,920,988	$37,617,437.50	$517,300,962.02
New York	5,065,968	456,350,244	$63,324,600.00	$1,976,907,033.96
Rhode Island	361,738	25,498,243	$4,521,725.00	$125,459,861.73
Vermont	104,369	9,163,525	$1,304,612.50	$39,814,669.36
Virginia	5,287,712	50,998,231	$66,096,400.00	$589,729,757.26
Sub-Total	**21,522,877**	**1,296,522,091**	**$269,035,962.50**	**$6,164,310,719.64**

Attachment 52

HOUSING INNOVATIONS IN ENERGY EFFICIENCY (HIEE)

CONTACT:

Daniel Farrell
daniel.farrell@dhcd.virginia.gov
Aaron Shoemaker
aaron.shoemaker@dhcd.virginia.gov

The Department of Housing and Community Development's (DHCD) Housing Innovations in Energy Efficiency (HIEE) funding makes energy efficiency upgrades to new and existing residential buildings to reduce energy bills for low-income Virginians. HIEE is funded through Regional Greenhouse Gas Initiative (RGGI) proceeds.

BACKGROUND

In 2020, the Commonwealth of Virginia became the first southern state to join RGGI, a regional cap and trade program designed to reduce climate pollution from fossil fuel power plants. Legislation passed by the Virginia General Assembly authorizes proceeds from these auctions to be used for community flood preparedness, coastal resilience and energy efficiency programs for affordable housing. DHCD will administer approximately 50% of the auction proceeds through HIEE, with technical assistance from the Virginia Department of Energy.

CURRENT STATUS

DHCD administers HIEE funds to enhance affordable housing programs benefiting low- to moderate-income (LMI) families in Virginia. For fiscal year 2021, HIEE funds are allocated to DHCD’s Affordable and Special Needs Housing (ASNH) program and the Weatherization Deferral Repair (WDR) Program . DHCD will continue to develop the HIEE program and other initiatives that will further benefit LMI families in fiscal year 2022 and beyond. ASNH and WDR information and program guidelines are posted under Resources.

STAKEHOLDER ADVISORY GROUP AND PUBLIC PARTICIPATION

If you would like to provide public comments at an upcoming meeting, please email **aaron.shoemaker@dhcd.vi** sign up. Each commenter will be given two minutes. To submit written public

HIEE-FUNDED PROGRAM RESOURCES

Weatherization Deferral Repair Page

Weatherization Deferral Repair Program Guidelines

Weatherization Deferral Repair Program Updates

HELPFUL LINKS

Regional Greenhouse Gas Initiative (RGGI) Auctions

Attachment 53

WEATHERIZATION DEFERRAL REPAIR (WDR)

CONTACT:

Jennifer Mares
jennifer.mares@dhcd.virginia.gov
For technical and compliance questions
Aaron Shoemaker
aaron.shoemaker@dhcd.virginia.gov
For project administration questions

The Weatherization Deferral Repair (WDR) program funds repairs that have caused homes (or units in multifamily buildings) to be deferred from the Weatherization Assistance Program (WAP). Once the needed repairs are made using the WDR funds and the home is "weatherization-ready," clients can then receive energy efficiency and health and safety measures available through WAP (such as insulation, air sealing, energy efficient light bulbs, and carbon monoxide detectors). Clients are required to sign an agreement with the weatherization agency, agreeing to both the WDR repairs and the weatherization services. Households may not receive the initial repairs without agreeing to also receive the weatherization services.

PERSONS SEEKING ASSISTANCE:

Contact the local weatherization agency serving your area.

For the Weatherization Deferral Repair (WDR) program, clients must work with the local weatherization agency serving their area through the Weatherization Assistance Program (WAP). In order to qualify for WDR, clients must meet WAP eligibility requirements.

FIND YOUR LOCAL WAP PROVIDER

FOR THOSE SEEKING RESOURCES

Weatherization Provider List by Organization

Weather Provider List by Locality

Weatherization Provider Map (find your locality and

WDR FORMS FOR SERVICE PROVIDERS

WDR Program Guidelines

WDR Program Updates

WDR Remittance Cover Sheet

WDR Application Form and Homeowner Agreement

OTHER HELPFUL RESOURCES

CAMS Overview Webinar Slides

CAMS Overview Webinar Recording

Attachment 54

WEATHERIZATION ASSISTANCE PROGRAM

Bipartisan Infrastructure Law Funds for WAP

Visual Guides for Home Energy Efficiency Upgrades

E&I and SERC Project Selections Announced

Bipartisan Infrastructure Law Funds for the Weatherization Assistance Program

View the Weatherization Program Notice to learn more.

Read the press release.

The U.S. Department of Energy (DOE) Weatherization Assistance Program (WAP) reduces energy costs for low-income households by increasing the energy efficiency of their homes, while ensuring their health and safety. The program supports **8,500 jobs** and provides weatherization services to approximately **35,000 homes every year** using DOE funds.

Through weatherization improvements and upgrades, these households save on average **$372 or more every year** according to a national evaluation of the program. Since the program began in 1976, WAP has helped improve the lives of more than 7 million families through weatherization services.

Contact Your Local Weatherization Organization for Weatherization Assistance

If you're interested in learning more about applying for weatherization services, contact your state WAP program and they can assist in identifying the local organization that serves your area.

VIEW MORE

Program Resources

Program Notices & Memorandums

Find active and archived Weatherization Program Notices and Memorandums.

Learn more

WAP Fact Sheet

Download and share the WAP fact sheet with your community leaders and decision makers.

Learn more

WAP Administrative Professional Training

Self-paced training geared toward WAP directors, fiscal, and administrative staff interested in implementing WAP at the local level.

Learn more

Energy Audit Tools

Learn more about the audit tools approved for use in the WAP.

Learn more

Guidelines for Home Energy Professionals

Explore the Guidelines for Home Energy Professionals, which support the development of a skilled residential energy upgrade

workforce.

Learn more

WAP Monitoring

Learn more on how WAP monitors the work to ensure high-quality work and energy savings for each client.

Learn more

Additional Links

- **WIP Project Map**
- **State Energy Program**
- **State and Local Solution Center**

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Attachment 55

Virginia Weatherization Deferral Repair Program Guidelines 2021 - 2022

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I. INTRODUCTION

The Department of Housing and Community Development (DHCD) administers the Weatherization Assistance Program (WAP) for low-income persons in Virginia, in partnership with a network of local weatherization agencies ("agencies"). DHCD is making additional funding available to the agencies through the Housing Innovations of Energy Efficiency (HIEE) program to assist households in Virginia who have been deferred from receiving WAP services to their homes due to needed repairs to ensure the effective installation of the WAP measures. HIEE funds are derived from the auction proceeds that DHCD receives from Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI).

DHCD refers to the HIEE funds used for this purpose as **Weatherization Deferral Repair (WDR) funds**. WDR funds are provided to weatherization agencies by DHCD via separate agreements from WAP, however these repairs are intended specifically to enable making the home "weatherization ready," and for the income-eligible household to receive weatherization services. *WDR funds are to be utilized only for repairs identified by the agency as causing the deferral of the home or unit from WAP*.

- For more information on HIEE, access the DHCD HIEE webpage.
- For more information on WAP and household eligibility requirements, access the WAP webpage.

II. WDR OVERVIEW

WDR funds are allocated to weatherization agencies specifically for repairs of the most common and frequently-cited issues causing WAP deferrals in Virginia: leaking roofs, minor structural, biological contaminants (e.g. mold), non-operational or unsafe HVAC unit, moisture issues, electrical, and plumbing. Other measures needed to bring the home out of deferral status and enable the home to be weatherized may be considered on a case-by-case basis. DHCD will cap WDR repair costs at reasonable and regionally-specific limits, as shown in Table 1. If estimated repair costs exceed the caps, the agency must contact DHCD so that the request may be evaluated. DHCD has appropriated $13.0 million in HIEE funds to be made available to weatherization agencies for WDRs starting July 1, 2021. Additional allocations of HIEE funds will be determined based on need and funding availability. Allocations are subject to final approvals by the Office of the Governor and Secretary of Commerce and Trade.

WDR funds are to be used solely to make repairs on income-eligible occupied homes and address the specific issue(s) that caused, or are causing, the home to be deferred so that the homeowner/tenant may regain eligibility for WAP and are NOT intended for full housing rehabilitation. Gut rehabilitations, projects requiring full plumbing, electrical and HVAC replacements, and major structural repairs (such as foundation repairs or collapsed roofs) are beyond the scope of WDR and WAP. Derelict, abandoned, and/or condemned homes are not eligible. If, in consultation with DHCD, agencies determine repairs needed to address the issue(s) causing the deferral and make the home weatherization-ready are beyond the scope of the WDR program, DHCD may work with agencies to refer these homes to local or other state

housing rehabilitation programs. For more detailed information see the section on eligible repairs.

III. FUNDING ALLOCATION

A. AGENCY AGREEMENTS AND REPAIR COSTS

The WDR Program requires agencies to adhere to a WDR Program Agreement, separate from the WAP agreement, beginning July 1. Allocation of WDR funds through these agreements is based on the agency's identification of eligible existing deferrals in its service area and estimated cost of the associated repair(s).

DHCD intends to ensure that agencies have a sufficient allocation of funds to initiate the necessary work to address their current deferral lists. WDR funds will also be allocated to ensure that the weatherization network overall is able to address the maximum number of deferrals that currently exist.

B. ADMINISTRATIVE COSTS

For agencies requesting less than $1.0 million in HIEE funds, DHCD will include an additional twenty (20) percent of the identified WDR allocation amount for agencies' administrative overhead and equipment costs with each agreement; those agencies requesting over $1.0 million will receive an additional ten (10) percent for administrative costs. Administrative costs may include accounting for the use of WDR funds, preparing reports for submission to DHCD, project management (e.g. obtaining evaluations/estimates on needed repairs, inspections of completed work), similar costs related to administering the funding, vehicle purchases or leases, and associated staff salaries. **As with all billed expenditures, billing for administrative costs must be based on actual costs incurred during a particular billing period.**

C. DEFERRAL TRACKING

Participation in the WDR program will require that all WDR recipient agencies participate in deferral tracking procedures established by DHCD. DHCD will work with the agencies to establish a consistent tracking procedure for deferrals that protects client confidential information. DHCD will distribute specific guidance on identifying and tracking deferral-related issues and repairs. As WDR projects are completed, the agency must accurately track the addresses of the projects to ensure that they are now eligible for WAP services. Agencies may establish their own systems and processes for re-engaging with clients and prioritizing WDR projects, but participation in the deferral tracking system will be mandatory. Agencies must adhere to DOE regulations for addressing completed WDR projects through WAP: the client should be integrated into the established weatherization queue based on the original intake date and should not go to the bottom of the priority list.

D. SERVICE PROVIDER/CONTRACTOR ELIGIBILITY

For WDR projects that agencies do not perform with their own staff, agencies must utilize subcontractors appropriately licensed and insured to perform the work needed to repair the issue(s) causing the deferral. Staff or subcontractors performing the WDR repairs are not

required to have WAP-specific training. However, subcontractors must be appropriately trained and credentialed in accordance with all relevant regulations, guidelines, and agreements.

E. SERVICE AREA

WDR funds may only be used to assist households in the municipalities of the Commonwealth of Virginia. WDR service areas are established for each funded agency based on the WAP service area. With explicit permission from DHCD, agencies may serve households in municipalities outside of the established service area. Allowances to serve outside the service area are based on the need, capacity, and available funding.

F. REALLOCATION OF UNSPENT FUNDS AND PERFORMANCE POOL

DHCD will actively review the expenditures of WDR funds by agencies regularly to ensure that the agency is progressing satisfactorily towards addressing needed repairs of deferred homes in its service area. Agencies are not required to spend 100% of funds allocated per the WDR Program Agreement in the contract year, but must demonstrate reasonable and substantial progress toward addressing the projected number of deferrals. Unspent funds may be rolled over into the subsequent program year agreement with approval from DHCD. However DHCD reserves the right to adjust WDR funding allocations or recapture/reallocate funding.

If at any point the agency has been identified by DHCD to have production issues that may compromise the success of the WDR Program, DHCD will confer with the agency to understand barriers and identify a production improvement plan and process. The agency must agree in writing to implement steps identified for production improvement. If issues relating to lack of production are unable to be resolved, DHCD reserves the right to de-obligate and reallocate part or all remaining funds subject to this agreement.

In addition, DHCD may set aside HIEE funds in a performance pool, which may be quickly allocated by addendum to existing agreements to agencies that are able spend all allocated HIEE funds for WDRs before the end of the agreement period and need additional funding to maintain their WDR repair pipeline.

G. MATCHING FUNDS AND COST CAPS

Matching funds are not required for WDR, and the agency cannot require a client contribution. If a repair estimate exceeds the regional cost caps (see Table 1), the agency may request an exception to exceed the limit. However, the agency must receive DHCD approval before proceeding.

H. VEHICLE PURCHASES AND LEASES

Prior written approval from DHCD is required for agency purchase of any vehicle with WDR funds. The cost of vehicles or equipment to support the program must be charged to the administrative budget category. Agencies must use approved bidding and purchasing procedures to acquire vehicles, or through a fleet contract. Vehicles will be titled in the name of the agency and a first lien in the name of DHCD must be placed on the title. Agencies must submit the title to DHCD upon receipt. Insurance coverage is required for vehicles purchased with DHCD funds.

Agencies must request permission from DHCD to sell or dispose of vehicles with a value greater than $5,000.00 purchased with WDR funds. DHCD must approve all vehicle leases prior to lease execution

IV. PROGRAM GUIDELINES

A. CLIENT ELIGIBILITY AND INCOME VERIFICATION

All clients (homeowners and tenants) must be determined as WAP-eligible (meet income guidelines) consistent with the procedures in the WAP Operations Manual. Agencies must receive property owner approval in writing for rental properties. Homeowners or renters must sign a service agreement with the local weatherization agency committing to the needed deferral repairs and the subsequent weatherization work. DHCD notes that all WAP clients participate on a voluntary basis. If it is determined up front that a client intends to forgo WAP services and/or will not sign the service agreement, they are ineligible for use of the WDR funds.

If it has been more than a year since the initial client intake, income eligibility must be re-verified. Agencies must prioritize serving income eligible clients first, along with immediate health and safety issues (such as unsafe combustion appliances or no heat/no A/C). Consistent with WAP guidelines, agencies have no obligation to serve potential clients who are unresponsive or hostile, or to offer services where dangerous or illegal activity is taking place.

If a client's income exceeds WAP eligibility requirements, weatherization agencies may refer the client to utility weatherization programs, which typically serve clients up to 80 percent of area median income (AMI). WDR funds may be used for deferral repairs for households with up to 80 percent of AMI, subject to availability of funds and the customer's agreement to participate in a utility-sponsored (investor-owned utilities and electric cooperatives/municipal utilities) weatherization program where those income limits are applicable.

B. ELIGIBLE REPAIRS

WDR funds are to be used solely for addressing needed repair(s) causing the home or unit to be deferred from WAP. The following repairs are most commonly-identified as causing weatherization providers to defer weatherizing the home and are eligible for WDR funding. The list is non-exhaustive and is subject to change. DHCD reserves the right to determine the eligibility of repairs or any costs not listed. All repairs must be code compliant and permitted if required by the Authority Having Jurisdiction (AHJ). Repairs not listed must be pre-approved by DHCD.

Roofs and minor structural

- Roof repair or replacement (e.g. roof leaks and attic cannot be insulated)
- Wall repair- interior or exterior (e.g., walls cannot support insulation without repair)
- Ceiling repair - interior (e.g., ceiling cannot support insulation without repair)
- Floor repair

Electrical, plumbing and HVAC

- Plumbing repair (e.g. water leaks that would damage insulation)
- Electrical repair (safety hazard or exposed wiring; cannot insulate due to presence of knob and tube wiring)
- Non-working or unsafe HVAC unit repair or replacement
- Non-working or unsafe gas/propane hot water heater repair or replacement
- Non-working or unsafe gas/propane range/oven repair or replacement

Hazardous materials

- Mold identification and remediation
- Suspected Asbestos Containing Materials ("SACM" e.g. attic, walls, pipes etc.)

The following are other issues that may cause WAP deferrals and may be remedied with repairs (requires DHCD pre-approval):

- Removal of vegetation (e.g. tree, bush, shrub trimming) needed to provide safe access to make eligible repairs
- Pest infestation
- Clutter restricting access to necessary areas

C. INELIGIBLE REPAIRS

The following repairs are not eligible uses of WDR funds. DHCD reserves the right to determine the eligibility of repairs or any costs not listed. The list is non-exhaustive and subject to change:

- Gut rehabilitation or major structural repairs (e.g. foundation, collapsed floor/roof)
- Replacement of entire plumbing, electrical, or HVAC systems
- Replacement of windows or doors where existing ones are not broken, missing, or damaged beyond repair
- Repairs covered by homeowner's or flood insurance
- Repairs needed due to willful damage or negligence on the part of the owner/occupant
- Cosmetic improvements (e.g. interior or exterior painting)
- Repairs to detached garages, barns, sheds, or storage buildings

TABLE 1 - REPAIR COST CAPS (BY REGION)

Eligible Measures/Repair Needed*	Northern VA	Central and Hampton Roads	Eastern Shore, Southside, and SWVA
Roof repair/replacement** (per project)	$10,300	$9,700	$9,500
Structural (per project)	$6,660	$6,200	$6,100
Hazardous material removal (e.g. mold, asbestos) (per project)	$14,000	$13,200	$12,800
Electrical (per project)	$5,600	$5,300	$5,200
HVAC unit replacement (per system)	$14,000	$13,200	$12,800
Plumbing (per project)	$2,700	$2,600	$2,500

*Cost limits are developed by triangulating three data sources including: The National Residential Efficiency Measures Database, RS Means 2020 Assembly estimates (normalized by city, state), and data collected from projects by the Virginia Center for Housing Research (VCHR) at Virginia Tech.
**Multifamily roof repair/replacement: NOVA: $3.40/FT^2; Central, and Hampton Roads: $3.20/FT^2; Eastern Shore, Southside, and SWVA: $3.10/FT^2. Roof repair/replacement is based on typical asphalt shingles; flat roofs requiring a membrane system will be more expensive so agencies should contact DHCD for exemption to cost cap.

V. FINANCIAL AND REPORTING REQUIREMENTS

A. CLIENT REPORTING/REQUIRED DOCUMENTATION

For each household served by WDR funds, the agency must retain the following:

- Documentation of incurred costs (timesheets, contractor invoices, materials and equipment cut sheets, etc.) to support all invoices, consistent with procedures for WAP jobs.
- A quarterly report including number of homes repaired, amount of WDR funds invoiced, and the nature of repairs accomplished.

B. PROJECT MANAGEMENT – CAMS

Agencies must manage documentation of WDR projects (applications, invoices, and reports) through the DHCD Centralized Application & Management System (CAMS). All grantees must be registered in CAMS and have approved audits in order to manage their project and receive payment. CAMS login and profile registration page may be accessed via the following link: CAMS login portal.

Agencies are responsible for managing their own staff access and user roles assignments.

The CAMS User Guide contains project management instructions including but not limited to:

- managing staff access and user role assignment
- submitting the agency audit
- requesting budget revisions
- submitting remittances (a.k.a. invoices, drawdowns)
- fulfilling reporting requirements

C. PAYMENT REQUESTS - SUBMITTING REMITTANCES IN CAMS

Payment is established based on the agreed-to repair estimate for each project. Agencies are encouraged to request payment in CAMS upon full project completion to the extent feasible, especially for smaller jobs (less than $5,000). However, agencies have the option to request payment on a draw-down basis, based on completing pre-established milestones as follows: homeowner and subcontractor agreement signed 10%, materials and equipment delivery, 60%, installation and project completion, 30%.

Prior to beginning each job, the weatherization agency or local service provider must submit the WDR Application Form and Homeowner Agreement signed by agency representative, homeowner, or landlord and tenant and WDR Authorization and Release in CAMS for reservation of funds to DHCD for approval and funding. The application will include site address, homeowner/tenant name, and a description of the repairs needed. The issues to be repaired/replaced must be photographed and submitted accompanying the WDR Application Form and Homeowner Agreement.

Once DHCD has approved the WDR Application Form and Homeowner Agreement, WDR Authorization and Release WDR Application Form and accompanying documentation in CAMS, agencies may either fund each repair upfront and request reimbursed by DHCD once the WDR Certification of Completion, financial supporting documents (i.e. contractor invoices, receipts) and photos of completed repair(s) have been submitted in CAMS as the remittance supporting documentation. Agencies may pay for the repairs and seek reimbursement or request funds to pay the contractor invoices upon completion on a drawdown basis as noted above. DHCD will not reimburse for work outside of the approved scope of work, or if work is determined to be substandard.

To initiate the payment process, the agency must submit remittances in CAMS. For each remittance, the agency must submit the required documentation which consists of:

- DHCD-provided signed cover sheet(template available on
- Invoice documentation (e.g. paid contractor invoices)
- Certification of Completion form
- General Contractor Affidavit, Warranty, and Lien Waiver
- Photos clearly showing completed work

All forms are available in CAMS or on the HIEE webpage.

The average time from submission to DHCD approval is 30 days for remittances that are accurate, complete, and include all required documentation at time of submission. If there are discrepancies or issues with the remittance documentation, and changes or resubmittals are required, the process may extend beyond 30 days. DHCD will reach out to the submitting agency regarding incomplete remittances.

D. METHOD OF PAYMENT

DHCD requires that agencies receive funds via electronic transfer. Instructions on establishing an account with the Virginia Department of Accounts (DOA) is located on their website through the selection of Electronic Data Interchange (EDI) from the link on the DOA main webpage. The EDI guide can then be accessed through a link under the Trading Partner Information section. Any grantee with unresolved findings or compliance issues, including for other programs, may have payments suspended.

E. ACCOUNTING AND FINANCIAL CONTROLS

Agencies must have established standard accounting practices including internal fiscal controls, standard accounting procedures, and track agency and program budgets by revenue sources and expenses.

VI. ADDITIONAL AGENCY REQUIREMENTS

A. COMPLIANCE WITH FAIR HOUSING AND CIVIL RIGHTS LAWS

(1) WAP agencies must comply with all applicable state and federal fair housing and civil rights requirements (see 24 CFR 5.105(a)). This includes the Virginia Values Act (effective July 1, 2020) which expands the list of protected classes under the Virginia Fair Housing Act. As the Virginia Fair Housing Act prohibits discrimination based on race, color, national origin, sex, pregnancy, childbirth or other related conditions (including lactation), age (over 40), marital status, disability, sexual orientation, gender identity, or veteran status (collectively the "Protected Classes"). (2) If the WAP agency: (a) Has been charged with an ongoing systemic violation of the Fair Housing Act; or (b) Is a defendant in a Fair Housing Act lawsuit filed by the Department of Justice alleging an ongoing pattern or practice of discrimination; or (c) Has received a letter of findings identifying ongoing systemic noncompliance under Title VI of the Civil Rights Act of 1964, section 504 of the Rehabilitation Act of 1973, or section 109 of the Housing and Community Development Act of 1974, and the charge, lawsuit, or letter of findings referenced in subparagraphs (a), (b), or (c) above has not been resolved before the application deadline, then the subgrantee is ineligible to apply for funds.

CONTACT INFORMATION

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Aaron Shoemaker
Program Administrator, Energy Efficiency Office
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Weatherization Assistance Program Contact:
Nancy Palmer
Housing Program Manager
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CAMS Issues and Troubleshooting
CAMShelp@dhcd.virginia.gov

Attachment 56

Weatherization Client Roof in Disrepair Resulting in Client Being Deferred for Weatherization Services

Utilizing Virginia RGGI Revenue to Support Existing Low-Income Energy Efficiency Programs

Chase Counts, CEM
Reducing energy burdens with weatherization at CHP Energy Solutions
Published Dec 11, 2020

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Energy efficiency and weatherization programs serving low-income, elderly, individuals with disabilities, and other energy burdened populations in Virginia have evolved dramatically since 2015. Federal resources through U.S. Department of Energy's Weatherization Assistance Program (WAP) and U.S. Department of Health & Human

have served as the foundational resource for weatherization services provider operations. In 2015, providers saw an increase in utility-sponsored energy efficiency programs which are designed to serve the same client base. In 2021, utility-sponsored programs will have increased by 19-times from their 2015 funding levels, exceeding the federal resources available for weatherization for the first time in Virginia's history.

Figure 1. Historic Funding Levels for Low-Income Energy Efficiency Programs in Virignia by Source, 2015-2021

While encouraging progress has been made to serve thousands more energy burdened households in Virginia, weatherization providers face challenges in service delivery to nearly 1 in 5 households that apply for their programs according to a 2020 survey by the Association of Energy Conservation Professionals (AECP) - the local trade association of weatherization providers in Virginia.

All 17 subgrantees in Virginia DHCD's weatherization program responded to the survey for the federal weatherization program year 2018 - the most recent program year uninterrupted by the COVID-19 pandemic. The survey revealed providers had to defer weatherization services to 525 households of the 2,901 applications received that year. Deferral issues vary in scope and scale, but the core is consistent: weatherization providers do not have the resources needed to address health and safety and other incidental repairs required prior to the installation of weatherization and energy saving measures.

Figure 2. AECP Weatherization Deferral Rate Survey Results for Program Year 2018-2019

moisture and other biological hazards, electrical issues, and more. These repairs are needed before weatherization providers can provide energy saving measures to these energy burdened households. Attic insulation, for example, cannot be installed if a leak in the roof may result in the insulation being compromised before the end of its expected useful life.

Access to home repair funds that could prevent these deferrals is sparse and inconsistent throughout the Commonwealth. Federal funds and utility-sponsored programs have limited health and safety and incidental repair funds available, averaging approximately 11-percent of the total funds available statewide, which have been further strained by additional personal protective equipment (PPE) needs resulting from the current pandemic. Those funds also come with many restrictions and are often insufficient to resurrect a weatherization applicant from deferral. Other funding sources include a handful of municipalities or private donations. Community Housing Partners (CHP), Virginia's largest non-profit weatherization provider, sets aside nearly $200,000 of internal funds each year to address health and safety issues and/or incidental repairs needed to unlock weatherization candidates' households to then deliver energy saving weatherization services. Even with the application of those extra funds, CHP still had to defer 197 jobs during the reporting period.

Figure 3. Weatherization Deferral Due to Roof Issues Resulting in Ceiling Damage

Based on the feedback in the survey responses, Virginia's weatherization providers estimate an average range of $5,000-$8,000 is often needed to bring a weatherization candidate back from deferral status. With the increase in funding available in 2021 and beyond, Virginia's weatherization provider network expects to complete an estimated 8,500 comprehensive weatherization retrofits per year for the foreseeable future. At current weatherization deferral rates, the weatherization providers can expect to defer

providers are not able to recover. At an average of $7,500 per household in health and safety and/or incidental repair funds serving 1,500 households per year, the weatherization network would like to leverage $11,500,000 of RGGI revenues each year in support of Virginia's most effective and shovel-ready energy efficiency program serving low-income, elderly, and individuals with disabilities to reduce their household energy burdens.

Considering new utility-sponsored programs beginning in 2021 will allow weatherization providers to braid federal resources to serve more multifamily properties, particularly in urban areas where gas heating and water heating are more prevalent and prone to health and safety issues, deferrals due to combustion safety hazards are expected to rise that were not captured on the AECP survey. Rough estimates anticipate an additional 20-percent of the projected $11,500,000 of RGGI revenues could be leveraged to address health and safety issues arising from gas appliances in disrepair at multifamily properties driving the leveraged funding request closer to $14,000,000 per year.

Figure 4. Commonly Reported Reasons for Deferral from AECP Survey

From historic records, the typical weatherized home in Virginia realizes approximately 28.54 MMBtu of energy savings annually, unlocking the energy efficiency potential of more than 1,500 households that would otherwise be weatherization deferrals could translate into an additional 43,000 MMBtu energy savings each year, offsetting greenhouse gas emissions while fulfilling the legislative intent of the 2020 House Bill 981 by supporting low-income energy efficiency programs. The weatherization network has demonstrated its ability to scale operations through the American Reinvestment and Recovery Act stimulus funding in 2009, and today amidst an increase in utility-sponsored programs that can be leveraged with federal resources.

weatherization clients' roofs will create additional opportunities to consider those households for distributed rooftop solar - complementing efforts like 2019 House Bill 2789's low-income solar and energy efficiency program and the work of the Virginia Clean Energy Advisory Board - to have a fair and equitable clean energy transition in Virginia.

The weatherization provider network requests the Virginia DHCD RGGI Stakeholder Advisory Group and all participating stakeholders consider the energy efficiency potential of this proposal while taking into account how RGGI revenues used for this purpose aligns with the intention of the legislation.

Sign up for updates and have your voice heard at the upcoming Virginia DHCD RGGI Stakeholder Advisory meeting on Tuesday, December 15, 2020 from 2-4 PM EST, by visiting Virginia DHCD's Housing Innovations in Energy Efficiency Program landing page here: https://dhcd.virginia.gov/hiee

For additional information, please contact:

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Kevin Brauer 2y
Great work! Wondering if opportunity to add ACA funds to address home-caused health issues?
Like Reply | 1 Like

Robert W. Lazaro, Jr. 2y
Chase you guys at Community Housing Partners and our friends at the LEAP (Local Energy Alliance Program) are doing great work in VA and the region. Keep it up!
Like Reply | 1 Like

Loren Ahonen 2y
This is fantastic. Great work here, Chase.
Like Reply | 1 Like

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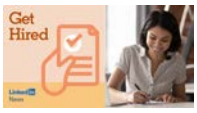

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Attachment 57

ENERGY NEWS NETWORK

SOUTHEAST

Virginia weatherization program is changing lives, but Gov. Youngkin wants to cut off its funding source

A Virginia program that uses money from the Regional Greenhouse Gas Initiative to help low-income residents with deferred maintenance and energy efficiency overhauls has been hailed by advocates as a national model.

by **Elizabeth McGowan**
September 21, 2022

Paul Acker, program manager with Community Housing Partners energy solutions division, speaks with Dorothy Carter on her front porch about upcoming installations. Credit: Everett Brubaker / Community Housing Partners

Dorothy Carter pined to remain in her Elkton, Virginia, home, but that possibility seemed less and less likely as health and safety issues mounted.

Sewage from broken pipes leaked into the basement. Rain poured in through holes in the roof. And blown fuses were a constant headache when she bypassed a balky oil furnace to warm rooms with space heaters.

But where would the 61-year-old go? And how would she gather the resources to move?

Fortunately, relief from that anguish began arriving in mid-August when a crew spent several days scrubbing away the sewage. That deep cleaning laid the groundwork for a phalanx of other contractors that are part of a now-at-risk Virginia program dedicated to tackling deferred home repairs that stand in the way of energy efficiency improvements.

Carter was again beaming on Sept. 13 as an electrician and several other contractors darted in and out of her rural Rockingham County house replacing her water heater and breaker panel. Within the next few weeks, she will gain a new roof, heat pump and water pipes.

Dorothy Carter of Elkton, Va., on her front porch in Rockingham County. Credit: Everett Brubaker / Community Housing Partners

“It will be so much nicer here when I come home from work,” said Carter, who has a job at nearby Friendship Industries, which employs people with disabilities. “They’re putting in stuff I can’t afford to buy.”

Carter is relieved the electric heat pump will end the $700 payments to fill her oil furnace.

“Now I’m going to call and tell them I don’t need it no more,” she said. “I’ve been here for about 43 years. There have been challenges, but I’m going to keep on living here.”

Carter is far from the only Virginian to benefit
from the new statewide initiative for low- and moderate-income residents designed to pair out-of-reach repairs with energy efficiency overhauls.

However, she could be one of the last if Republican Gov. Glenn Youngkin succeeds in his quest to extract his state from an East Coast carbon cap-and-invest enterprise Virginia joined in 2020. Virginia targeted a share of its Regional Greenhouse Gas Initiative dollars to lift up Carter and other homeowners struggling to modernize basic infrastructure that keeps houses ticking.

Briefly, what's known as RGGI curbs the emissions of heat-trapping gases from fossil fuel power plants by auctioning carbon dioxide allowances. Facilities are assigned a cap on how much carbon dioxide they can emit, and they must purchase allowances for any pollution above that threshold. The 11 member states decide independently how to spend the revenue.

Virginia's General Assembly opted to direct roughly half of the annual auction proceeds to a range of energy efficiency programs for lower-income households. Programs are administered by the Department of Housing and Community Development.

Through June, records show the state agency has distributed $189 million in RGGI funds toward energy efficiency from its start date in March 2021.

Sara Hayes, a health and environment specialist with the research nonprofit American Council for an Energy-Efficient Economy, praised Virginia for directing a RGGI allotment toward big-ticket home repairs that aren't covered by traditional weatherization programs funded by utilities and the federal government.

"I have huge kudos for the people in Virginia who made that happen," Hayes said about a front where other states are lagging. "That kind of coordination rarely happens.

"Virginia created a program that outshines everybody. Why would you wake up one day and say you're going to get rid of a wildly successful framework?"

Everett Brubaker asks the same question.

As a Harrisonburg-based business development specialist with the energy solutions division of Community Housing Partners, he's been an eyewitness to the impact of the RGGI cash infusion. His

employer is the largest of 15 nonprofits statewide qualified to **perform weatherization services**. It's also coordinating the repairs at Carter's house.

In years past, these nonprofits couldn't undertake more run-of-the-mill weatherization until health and safety threats such as mold and leaky roofs were tackled. Cases placed on what's known as the deferred list lingered because local charities were often too strapped to step up.

"I don't think people realize that many of their neighbors are living in these conditions," said Brubaker, who visited Carter's house with work crews. "It's not like she's an exception."

Ed Bradley and a crew member with Bradley Electric carry a new water heater to Carter's home. Credit: Everett Brubaker / Community Housing Partners

Advocates: Legislators control RGGI's destiny

Youngkin's administration has targeted RGGI withdrawal as a priority since Virginians elected the Republican governor last November. In January, he issued an executive order calling for an exit.

Then, in late August, at a regular meeting of the Virginia Air Pollution Control Board, acting Natural Resources Secretary Travis Voyles announced the administration's intention to file the paperwork to extract the state from RGGI by the end of 2023.

Environmental advocates **have vowed** to beat back that repeal.

Conservation attorneys claim withdrawal is an act of overreach by the governor and regulators.

"The lawmakers who do have that authority in the General Assembly know RGGI is already delivering real resources to Virginians on the frontlines of climate change," said Nate Benforado, a senior attorney with the Southern Environmental Law Center. "It would be a colossal mistake to pull out of a program that is … helping Virginians solve real problems they often can't afford to tackle alone."

Sixty-one Democratic state legislators echoed that perspective in a **September letter**, stating that, "only a change in the law that passes both chambers of the General Assembly and is signed by the Governor can remove Virginia's participation. No proposed regulation, emergency regulation, regulatory act, or any subsequent administrative process can do so."

Virginia's journey to becoming the first southern state to RGGI has been circuitous and twisted. Democratic Gov. Ralph Northam, whose four-year term ended in January, backed membership.

After years of obstruction, the General Assembly finally voted to join the 2008 initiative in 2020. With **House Bill 981**, legislators tasked the Department of Environmental Quality with establishing parameters for the Clean Energy and Community Flood Preparedness Act. The RGGI money is split between flood mitigation projects and energy efficiency.

The state is **funding two other non-weatherization housing initiatives**. Both target low- and moderate-income Virginians. One "bucket" covers energy efficiency efforts for new construction, rehabilitation, and adaptive reuse of affordable and special needs housing. The other, not yet rolled out, is a grant program for housing innovation partnerships.

During this year's legislative session, the Republican-majority House of Delegates voted to halt RGGI participation. But the Senate, where Democrats have a slim lead, thwarted that effort by deep-

sixing a similar bill in its conservation committee.

Chelsea Harnish, executive director of the Virginia Energy Efficiency Council, is urging Virginians to voice support for RGGI by submitting comments to the state Department of Environmental Quality during the Sept. 26-Oct. 26 window.

“This money has been instrumental in moving homeowners in the most dire need of help off the deferral list,” Harnish said. “Before, providers were having to walk away from those in need. With RGGI funding, they don’t have to do that anymore.”

She emphasized that the pot of money RGGI provides is far greater than all other energy efficiency and weatherization programs combined at the federal and utility level.

Harnish pointed to how Project: HOMES deployed a portion of its $16 million from RGGI to fix up 12 Eastern Shore homes initially tagged for the deferral list. The nonprofit hired 30 local subcontractors to address roof, mold, insulation, and heat and cooling issues before engaging in more routine weatherization. Homeowners’ utility bills have dropped by about 20%.

The state Department of Housing and Community Development did not respond to requests for comment about RGGI funding potentially being in jeopardy. While the agency is the clearinghouse tracking how the 15 nonprofits are spending RGGI money, those collective figures are not available. However, each nonprofit is recording its individual statistics.

For instance, since July 2021, Community Housing Partners has spent $1.2 million serving 226 households in need of RGGI pre-weatherization repairs.

Another 325 households remain in the repair queue. Currently the nonprofit has $1.3 million on hand to address those needs.

While Virginia will certainly benefit from clean energy provisions in the Inflation Reduction Act, Harnish said that federal law is no substitute for RGGI money that provides weatherization deferral repairs.

“It’s comparing apples and oranges,” she said. “While IRA money coming to the states is historic, it isn’t going to help fix roof or mold problems.”

In a nutshell, the IRA offers multiple rebates and tax credits for electric appliances and overall energy savings.

For instance, states will administer the IRA rebate program "and we don't know what that will look like yet," Harnish said.

She was pleased that Hayes, with the American Council for an Energy-Efficient Economy, had lauded Virginia for acting boldly with its RGGI funding.

"It's wonderful to hear a national nonprofit referring to us as a model," Harnish said. "And now our governor wants to take away that money."

RGGI money gives Virginia a boost

Virginia ranked a respectable 19th in an overarching state energy efficiency scorecard that Hayes and three other ACEEE researchers released in mid-August. Overall, the authors discovered that no state is knocking it out of the park with efforts to support healthy, affordable and decarbonized homes.

Maryland, Virginia's neighbor to the north, was the top finisher with 54.5 out of a possible 100 points. Virginia tallied 29 points.

In the 119-page "Pathways to Healthy, Affordable, Decarbonized Housing," ACEEE evaluated each state across 33 possible actions that could reduce pollution and housing costs for residents through energy efficiency, electrification and renewable energy investments.

Detailed categories covered energy utilities, weatherization and bill assistance, affordable housing, healthy homes and communities, and cross-agency coordination.

While Virginia's list of shortcomings is lengthy, it earned points for funneling RGGI dollars into its unique weatherization repair deferral program that benefitted Carter and hundreds of others.

"Usually, these programs happen because they have champions who develop relationships with people in other agencies," Hayes said. "That takes time and effort.

"Virginia is reaching the neediest by building a mechanism where money can help people being harmed in their homes."

Hayes and her colleagues opted to undertake this first-of-its-kind report because people's homes are linked to their health and their economic circumstances. That became even more apparent during the pandemic.

"We wanted to come at it holistically and we didn't want to advocate policies that don't take people into account," said Hayes, a 20-year energy policy veteran. "As the climate changes, how do we make sure those hit the hardest can survive?"

Lower-income people not only have higher energy burdens because their inefficient homes consume more energy per square foot, Hayes said, but they also pay higher utility bills because of gaping problems with mold, roofs and windows.

Rhode Island, California and Vermont, which ranked two, three and four, were the only states with marks of 50 or higher. She also noted that five of the 10 bottom-ranking states lead the nation in poverty rates.

The report provides a potential roadmap for ambitious states.

"But they have to get into the weeds," Hayes said. "We've done the work of saying, 'Here is the body of things you need to address.' To take action, states have to look at what they do have and don't have."

A brighter Christmas

Carter is grateful her home, built in 1962, will be buttoned down before cool weather envelopes the Shenandoah Valley.

She began falling behind on upkeep when her husband, Chester, died 26 years ago. They had moved into the family home after marrying in 1979.

Carter is so enamored with the upgrades Community Housing Partners is coordinating that she is serving as an informal ambassador for the program. She's puzzled why Youngkin seems so intent on dismantling it.

"I've talked to family members, neighbors and coworkers about how it can help," she said. "I don't know why [the governor] can't just leave it alone and let it keep going. There are a lot of people out there who can't afford what it provides."

With some of her savings on utility bills, Carter plans to purchase a washer and dryer — and also splurge a bit during the holiday season.

“A friend asked me why I didn’t decorate at Christmas. I told her I ain’t got time to blow no fuses.”

Later this year, the two women will string dazzling arrays of lights.

With my new electrical box,” Carter said, “I can put out a lot of Christmas stuff.”

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Attachment 58

Affordable and Special Needs Housing
Competitive Application
Program Guidelines

FY 2023

Applications Due:
October 31, 2022
March 31, 2023 (tentative)

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Program Overview

Background

The Affordable and Special Needs Housing (ASNH) Program is a consolidated, competitive application used by the Virginia Department of Housing and Community Development (DHCD) to award National Housing Trust Fund (NHTF), HOME Investment Partnerships (HOME), Virginia Housing Trust Fund (VHTF), Housing Innovations in Energy Efficiency (HIEE), and Permanent Supportive Housing (PSH) funds[1] to multifamily rental developments and single family homeownership developments across the Commonwealth.

The Program's goals are to expand the supply of decent, safe, sanitary, and affordable housing available to low-income, very low-income, and extremely-low income Virginians.

Eligible projects are scored on a 100 point scale (Need – 40 points; Feasibility – 30 points; Developer Capacity – 30 points) and projects with scores above a 60 point threshold are ranked and considered for funding awards of the sources above.

These Program Guidelines are intended to provide guidance on applicant and project eligibility, program and regulatory requirements, funding availability and limits, as well as the application and decision notification process for the FY23 ASNH application cycle. If you require information not contained below, please contact DHCD staff for assistance.

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[1] DHCD also uses HOME, VHTF, and HIEE funds for other eligible activities administered by other programs.

Funding Sources Available

HOME

The *HOME Investment Partnerships Program* (HOME) was created through the National Affordable Housing Act of 1990. Funds from the HOME program are made available annually through formula allocations to states and local governments (*Participating Jurisdictions* or PJs).

PJs are responsible for conducting needs assessments and establishing priorities and goals, and developing and managing the programs that will help meet these goals. The ASNH Program is a subset of DHCD's HOME funding, and uses HOME to support the development of rental units made available to individuals or families with incomes at or below 50% or 60% of their Area Median Income (AMI), and to the development of homeownership units made available to buyers with incomes between 60% and 80% AMI.

While projects may be located anywhere in Virginia, DHCD's HOME program gives priority to projects located in cities or counties which do not receive a direct federal HOME allocation through a local PJ or HOME Consortium through a scoring preference. The list of cities and counties which do not receive a scoring preference are listed in **Appendix A**.

The ASNH program also gives DHCD-certified Community Housing Development Organizations (CHDOs) a scoring preference for HOME funding. See DHCD's online resources for more information on CHDO requirements.

National Housing Trust Fund

The *National Housing Trust Fund* (NHTF) was created as a federal block grant to states, issuing its first allocation in 2016, and is the largest federal program designed to specifically support the production and preservation of affordable housing for extremely low income individuals and families.

DHCD awards all of its NHTF funds through the ASNH Program, and uses NHTF to support the development of rental units made available to individuals or families with incomes at or below 30% AMI.

Virginia Housing Trust Fund (Competitive Loan Pool)

The *Virginia Housing Trust Fund Competitive Loan Pool* is funded through Virginia's Housing Trust Fund, which is a special allocation of state funds intended to help address the commonwealth's housing needs and reduce homelessness. No less than 80% (eighty percent) of the VHTF must be allocated to a competitive loan pool.

The ASNH Program satisfies this requirement for a competitive loan pool, and provides low-interest loans to meet the financing needs of housing projects which address key state housing policies. Funds may be awarded to projects developing rental units or for sale homes which are made available to individuals or families with incomes at or below 80% AMI.

Virginia Housing Trust Fund expenditures associated with projects funded through the ASNH program will be used to meet the State's federal HOME program match requirement and may not be utilized for any subsequent regulatory match requirement without permission from DHCD.

State Permanent Supportive Housing Funds (PSH fund)

The State *Permanent Supportive Housing Funds* (PSH fund) are awarded to support the development of new permanent supportive housing (PSH) units. Supportive housing is an evidence-based housing intervention that combines non-time-limited affordable housing assistance with wrap-around supportive services for people experiencing homelessness, as well as other people with disabilities.

These funds are typically awarded to small development projects which specifically aim to provide independent living options for individuals with intellectual or developmental disabilities or serious mental illnesses, and which assist DHCD in meeting the requirements of the Department of Justice Settlement Agreement. These projects may be 100% 'special needs' populations and exempt from the five-unit minimum.

Housing Innovations in Energy Efficiency (HIEE) Funds

Housing Innovations in Energy Efficiency (HIEE) funds assist affordable housing project development teams in completing energy efficiency upgrades that would not have been feasible otherwise. These funds are made available by DHCD to projects which demonstrate that they are designed to meet the HIEE energy efficiency performance requirements detailed below, and supplement competitively awarded state and federal funds.

Projects must score well enough to obtain an award of ASNH's competitive sources (HOME, NHTF, VHTF, or PSH) to be eligible for an allocation of HIEE funds. During the application review process for each cycle, the panel will score and rank projects to determine competitive award recommendations. If a project which requests HIEE funds is recommended for a competitive award, the panel then evaluates the additional required documentation to ensure the project is designed to meet the relevant energy efficiency performance requirements. HIEE energy efficiency performance requirements are detailed in **Appendix B.**

Program Year Available Funds

For the 2022-2023 program year (Virginia FY23), the sources and approximate amounts allocated to the ASNH Program are below. DHCD reserves the right to update these funding amounts during the program year, and the right to roll over funding to future program years at its sole discretion.

Per project and per source maximums awards apply, with further details below and under Eligibility Criteria. DHCD reserves the right to restrict total funds awarded to a project.

SOURCE OF FUNDS	FY23 ALLOCATION[2]
HOME Investment Partnerships Program (HOME)	$8,766,531
National Housing Trust Fund (NHTF)	$12,975,688
Virginia Housing Trust Fund (VHTF)	$60,000,000
Housing Innovations in Energy Efficiency (HIEE)	$80,000,000
State Permanent Supportive Housing (PSH fund)	$500,000

Project Competitive Funding Limits

Each eligible project is subject to funding request limits, or caps. These caps are inclusive of all DHCD commitments to a project in previous application cycles. DHCD reserves the right to adjust funding offers by funding source to meet project needs, and reserves the right to limit funding offers made to a project even if 'cap' remains.

DHCD will consider excluding Vibrant Community Initiative VCI) commitments from these caps if such a request is made in writing prior to application. Exclusion of VCI commitments is not guaranteed and is granted at DHCD's sole discretion on a case-by-case basis.

Projects with HOME assistance from any source are ineligible for an award of HOME funds from the ASNH Program while the project is in its HOME affordability period.

Each project is limited to an award of $700,000 per competitive source (HOME, NHTF, or VHTF); with an increased limit of $900,000 for any two of those three sources if the project provides qualified Permanent Supportive Housing (PSH) units, as detailed in Criteria below, and provides the required documentation at the time of application.

- $700,000 – Maximum request per source (HOME, NHTF, or VHTF)
- $900,000 – Maximum request per source for projects providing qualified PSH units
- $2,100,000 – Maximum award for a project requesting HOME, NHTF and VHTF
- $2,400,000 – Maximum award for a project providing qualified PSH units and requesting HOME, NHTF, and VHTF

The State Permanent Supportive Housing fund (PSH fund) award is limited to $500,000 per project, and are typically awarded to small development projects which are either not are eligible for or do not request an award of HOME, NHTF, VHTF awards.

[2] Allocation amounts listed are approximate and subject to change.

Project HIEE Funding Limit

Each project earning a competitive source award (HOME, NHTF, VHTF, or PSH fund) which is designed to meet the HIEE minimum performance requirements is eligible for an award of up to $2,000,000 or ten percent (10%) of its total construction costs as calculated in the ASNH Application Workbook underwriting tab, whichever is the lesser amount.

- $2,000,000 – Maximum HIEE award for an eligible project
- $4,100,000 – Maximum total awarded funds for an eligible project requesting HOME, NHTF, VHTF, and HIEE
- $4,400,000 – Maximum total awarded funds for an eligible project providing qualified PSH units and requesting HOME, NHTF, VHTF, and HIEE

Eligibility

Applicant Eligibility

Eligible Applicants are non-profit organizations or for-profit housing developers, DHCD-certified Community Housing Development Organizations (CHDOs), and public housing authorities seeking to develop affordable housing projects in Virginia.

The Applicant must be the Owner, Developer, or Sponsor of the proposed project:

- Owner – holds valid legal title to, or long term leasehold interest in the property
- Developer – owns the property and is developing the project, or has a contractual obligation to develop the project
- Sponsor – is the owner or partial owner and agrees to convey ownership to a second non-profit at a predetermined time prior to or during development or upon completion (requires consultation with DHCD prior to application)

The Applicant must be registered in CAMS as an eligible organization defined above, and should be the primary partner in the project, responsible for long-term operations and compliance. Applicants with incomplete CAMS profiles (including applicants without UEIs) are ineligible.

Applications made by a project legal entity or limited liability corporation are ineligible.

Applicants with outstanding or unresolved findings from audit or monitoring findings, unresolved IRS findings, unresolved compliance findings – including those issues which may be identified to DHCD by another previous partner such as Virginia Housing (VH or VHDA) –, or which are not in compliance with previous DHCD agreements will not be eligible for a funding commitment for any Project until such findings and/or compliance issues are resolved. DHCD staff are committed to working with any interested party to develop a plan for resolution and restoration of eligible status.

Developer Requirements

Federal regulations require DHCD to certify developer capacity, including Community Housing Development Organizations (CHDOs) prior to the commitment of HOME or NHTF funds.

The evaluation of developer capacity includes reviewing:

- Developer's demonstrated experience developing similar projects
- Staff experience in housing development (excluding consultants, contractors, or partners)
- Current financial soundness, including compliance with DHCD's audit policy

DHCD also evaluates the capacity of applicants requesting only state sources of funding. It is critical that applicants and development teams have demonstrated success with similar projects including ongoing operations and long-term compliance. Applicants must be able to clearly articulate the relationship between all partners involved in the development, ownership, and property management of a project, and describe partner capacity and experience.

CHDO Certification Requirements

Applicants must have an approved CHDO Certification application in CAMS, and the related Certification or Re-Certification letter provided by DHCD to be eligible for the five (5) point scoring preference on applications for HOME funds. This scoring preference enables DHCD to meet the 'CHDO Reserve' or 'CHDO set-aside' requirements of the HOME program.

Generally, CHDOs must meet organizational, mission, financial management, and capacity requirements, which include, but are not limited to, the following:

- Certified nonprofit status
- Being a community-based organization
- Low-income representation in board composition
- Primary mission is the provision of affordable housing
- Demonstrated capacity to develop affordable housing
- Conformance to accounting standards and financial soundness

CHDO requirements must be met at the time of fund commitment, for the duration of the development phase, and through the long-term compliance period for CHDO's in the role of project/property owner.

Organizations interested in determining if they meet the requirements to become certified as CHDOs and therefore eligible for the HOME scoring preference should refer to the HUD publication CHDO Survivor Kit[3] or the CHDO Capacity Self-Assessment Tool

Project Eligibility

To be eligible for ASNH funding, all projects must be new construction or substantial renovation of affordable housing units, or the adaptive reuse of buildings to create new affordable housing units for lower income homeowners or renters. Acquisition-only projects, public housing, and public facilities including emergency shelter, hospitals, nursing homes, or intermediate care or assisted living facilities are not eligible for ASNH funding.

In limited cases group homes may be eligible for ASNH funding. There must be an identified local need, and these projects require a pre-application consultation with DHCD. Applications submitted without completing this pre-application consultation are ineligible.

[3] Link validated September 2022; document title is searchable on hudexchange.info

Eligible property types include multi-unit structures, single family, two- to four-unit structures, and manufactured homes. Scattered site projects are allowable, but all projects must be under common ownership, management, and financing. Regardless of type, the units must be considered modest relative to the neighborhood.

Projects may include units structured as Single Room Occupancy (SRO) units. Eligible SROs are efficiency-style units that are the primary resident of a single one- or two-person household, with a valid twelve-month lease to that household. The unit must contain food preparation and/or sanitary facilities. If the unit does not contain food preparation or sanitary facilities, then the building must contain and provide access to these.
Generally, an eligible project must:

- Include a minimum of five units,
- Be under common ownership, management, and financing,
- Represent a minimum investment/development cost of $15,000 per unit, and
- Meet the affordability requirements of every source for which it is requesting funds.

Eligible Project Types

Projects may be new construction, substantial rehabilitation, or adaptive reuse. Development activity beyond the original footprint will be considered new construction. Projects must meet Section 504 accessibility requirements based on project type, as described in these Guidelines.

For rehabilitation projects, minimum total development cost per unit is $15,000 and must include replacement of at least three out of five major systems (e.g., HVAC, plumbing, roofing, electrical). Development costs are limited to eligible costs and must exclude non-eligible costs such as community buildings, market rate units, and retail space.

Projects of any type must meet DHCD's Minimum Design, Construction, and Rehab Requirements to ensure that no further investment is required during the affordability period. Projects awarded National Housing Trust Funds must follow the Housing Trust Fund Rehabilitation Standards.

Rental & Homebuyer Project Eligibility

An eligible project must be either a **homebuyer** project or a **rental** project (not both).

Homebuyer projects must be a minimum of five units of housing, which will be made available for sale to households earning incomes below 80% AMI. These projects may apply for either HOME or VHTF funds.

Rental projects must be a minimum of five units (unless 100% special needs, with DHCD approval), and must be structured to meet each individual program's affordability requirements. For rental projects requesting federal sources, a minimum of five units are required to meet AMI targeting requirements per source.

For example, a project requesting HOME and NHTF funds would need a minimum of ten total units, five of which must meet the NHTF requirement of 30% AMI or below; and five of which must meet the HOME requirement of 60% and 50% AMI or below. Rental projects requesting

state funding sources (VHTF, PSH funds, or HIEE) must restrict at least some units to households with incomes at or below 80% AMI.

Mixed income and multiple-use projects are eligible; however these projects must contain assisted units that will meet income and rent or sales value requirements, and the number of assisted units must meet Program Guidelines.

For both homebuyer and rental projects, applications designed to provide a greater proportion of lower income targeting will be given scoring preference on the *need* criteria. The actual number of ASNH assisted units and income mix will be determined by DHCD during underwriting.

For both homebuyer and rental projects, the maximum investment of HOME or NHTF funds must be equal to or less than the actual costs *or the 221 (d)(3) limit*, whichever is lower, on a per-assisted-unit basis.

Maximum Subsidy Limit – *221(d)(3) limit* (effective March 17, 2022)	
Bedrooms	Cost Limit
0	$159,754
1	$183,132
2	$222,694
3	$288,094
4+	$316,236

Program requirements including the number of required assisted units are based on total amount of HOME or NHTF assistance (including HOME from other resources) as compared to the total development costs. For this purpose, total development costs are limited to HOME or NHTF eligible costs (Appendix C) and must exclude non-eligible costs such as community buildings, market rate or unrestricted units, and retail space.

The final number of assisted units in a project will be determined by DHCD during underwriting. Selected projects will always be assisted with the minimum amount of funds needed, as demonstrated by the underwriting and subsidy layering review.

Program Terms & Agreements

Affordability Period

All commitments of ASNH funds to a project result in a mandatory affordability period on the project property, which is the period of time that the rental units or single family home must be maintained as "affordable" according to the agreement between the developer and DHCD, and is enforced through a restrictive covenant deed recorded on the property.

Affordability periods for ASNH funded rental projects are thirty (30) years. As noted below, for HOME-assisted projects, this affordability period is comprised of a federal compliance period followed by a state-level affordability period. For all sources, the required type and number of

source-assisted units to be maintained as "affordable" for this time period determined by DHCD during underwriting.

For ASNH funded homeownership projects, the affordability periods for any available source are based on the total amount of funds (including HOME funds from local Entitlements or Consortiums) invested in the project and DHCD's determination of investment through developer subsidy or direct homeowner assistance.

Rental Affordability Periods	
Source/Activity	**Length**
NHTF (all activities)	30 years (federal compliance only)
HOME New Construction	20 years (federal compliance) + 10 years state affordability)
HOME Rehabilitation	15 years (federal compliance) + 15 years state affordability)
VHTF, HIEE, and PSH funds	30 years (state compliance only)

Homeownership Affordability Periods	
Investment By Unit	**Length**
HOME or VHTF/HIEE; less than $15,000*	5 years
HOME or VHTF/HIEE; $15,000 - $40,000*	10 years
HOME or VHTF/HIEE; more than $40,000*	15 years

**If only homebuyer developer subsidy, a resale provision applies. If DHCD DPA is included in a unit then a recapture provision applies and affordability is based on the amount of DPA only.*

Type of Assistance Provided

Funds made available through the ASNH Program have standard terms based on project type.

Rental project assistance is provided as permanent, must pay debt after all other financial commitments are received. These funds are leveraged to close a financing gap in the affordable housing project, and the amount of funds committed must be the minimum amount needed.

All rental project applications must assume permanent financing structured as a 3% interest-only, deferred principal loan, with must-pay interest over the full required affordability period of time of 30 years. Cash flow loan requests will not be considered. Construction draws or other payments of ASNH funds prior to conversion to permanent financing will not be considered.

Homebuyer project assistance is structured as reimbursement-based construction financing. Construction draws are allowed based on predetermined and specific project completion milestones. No reimbursement draws are permitted until DHCD has received a fully executed deferred loan agreement, and a copy of the restrictive covenant deed of trust recorded on all properties under the loan agreement. Reimbursement draws or remittances are sent to the Applicant's organization address as listed in CAMS via paper check until the organization completes registration with the Department of Accounts for ACH payments.

This structure may also be available to rental projects with only PSH funds assistance.

For all projects, DHCD reserves the right to charge agency-incurred project costs to the project. These costs include only actual, applicable project costs such as environmental review notices and legal services. Any incurred costs charged to the project are structured as a grant, included in the total amount of project assistance. The total ASHN project assistance is reflected in the restrictive deed, the program agreement, underwriting, and subsidy layering analysis.

Additional Criteria

Income Restriction Criteria

Each ASNH awarded source has income restriction criteria, and regulations about how and when income determinations or qualifications are made.

Projects must be able to meet the ASNH Program requirement of a minimum of five units, but the actual number of assisted units in a project will be determined during underwriting. These units must be made available to eligible households that meet the income-restriction requirements of the source based on Area Median Incomes (AMI). Income calculations must be based on HUD's Section 8 income eligibility standard.

For all projects, households must meet income-restriction eligibility requirements at the time that program eligibility is determined, and determinations expire after six months.

For rental projects, all NHTF-assisted units must be restricted to households with incomes at or below 30% AMI; HOME-assisted units must be restricted to households with incomes at or below 60% AMI, and twenty percent (20%) of HOME-assisted units in a project must be further restricted to households with incomes at or below 50% AMI. VHTF and HIEE assisted projects must have units restricted to households with incomes at or below 80%. All ASNH sources allow for rental projects to be mixed-income and/or include 'workforce units,' market-rate or unrestricted units, but these projects must have appropriate numbers of restricted units to meet program requirements and have eligible costs to support the ASNH award value or investment.

For homebuyer projects, all sales must be made to households at or below 80% AMI regardless of ASNH source. For homebuyer projects, closing must occur within six months of income determinations. If closing does not occur during that time, then income eligibility must be re-established.

HOME Program Criteria

Match Funds and non-Entitlement Preference

Eligible projects may be located in any locality in Virginia. For projects requesting HOME funds, there are criteria that change based on the locality in which the project will be developed.
Some localities in Virginia, called HOME Entitlements or HOME Consortiums, receive HOME funds directly from HUD.

Projects located in these localities (listed in **Appendix A**) must meet a *local match requirement*. These projects must have a commitment of 25% of their ASNH Program HOME funds request from locally-administered funds. Examples of local match include local HOME, CDBG, or other federal or state funds awarded and administered by a local government. Match requirements can also be met based on the waiver of locally collected fees directly associated with the specific development (e.g., water and sewer connection fees). Documentation of local match must be included in the application.

Projects located in non-Entitlement or non-Consortium localities do not have a match requirement on their application for ASNH Program HOME funds, and have a scoring preference of 5 points on their HOME funds score.

HOME Environmental Reviews

Projects awarded HOME funds will require an additional environmental record review completed and approved by DHCD. **No development activity including the acquisition of the property can occur prior to the completion of this review, which may include the publication of a notice of findings and the request for release of funds from HUD.** Projects proceeding with development or 'choice limiting' activities prior to the completion of the review may be ineligible.

Coordination of the environmental review will be required for any project combining DHCD's State HOME funds with local HOME or Community Development Block Grant (CDBG) funds.

NHTF Program Criteria

NHTF Environmental Reviews

Projects awarded NHTF funds will require an additional environmental record review. The NHTF Environmental Provisions for new construction and rehabilitation under the Property Standards at 24 CFR § 93.301(f)(1) and (2) are similar to HUD's Environmental Regulations at 24 CFR Parts 50 and 58 for HOME funds. The main difference is that the HTF Environmental Provisions are outcome based, and exclude consultation procedures (including notice requirements and public comment periods) that would be applicable if NHTF project selection was a federal action. Parts 50 and 58 are process based, and include consultation procedures for several laws and authorities where there may be environmental impacts. See CPD notice 16-14 for further details.

Permanent Supportive Housing Criteria

Rental projects may include permanent supportive housing (PSH) units, which is permanent housing made available to individuals in qualified target populations in which supportive services are provided to assist at least that individual (who may be a member of a multi-person household) in achieving housing stability. These units may also have housing assistance in the form of rental

subsidies, or the individuals may have their own tenant-based rental assistance. Projects may target special needs populations such as veterans, formerly homeless, or elderly individuals.

However, for the purposes of achieving a scoring preference (5 points) or accessing the increased funding cap, projects must target households which meet the HUD definition of chronic homelessness, households with at least one member with an intellectual or developmental disability (ID/DD), or households with at least one member with a serious mental illness (SMI).

The minimum number of PSH units required per project to gain the scoring preference is as follows:

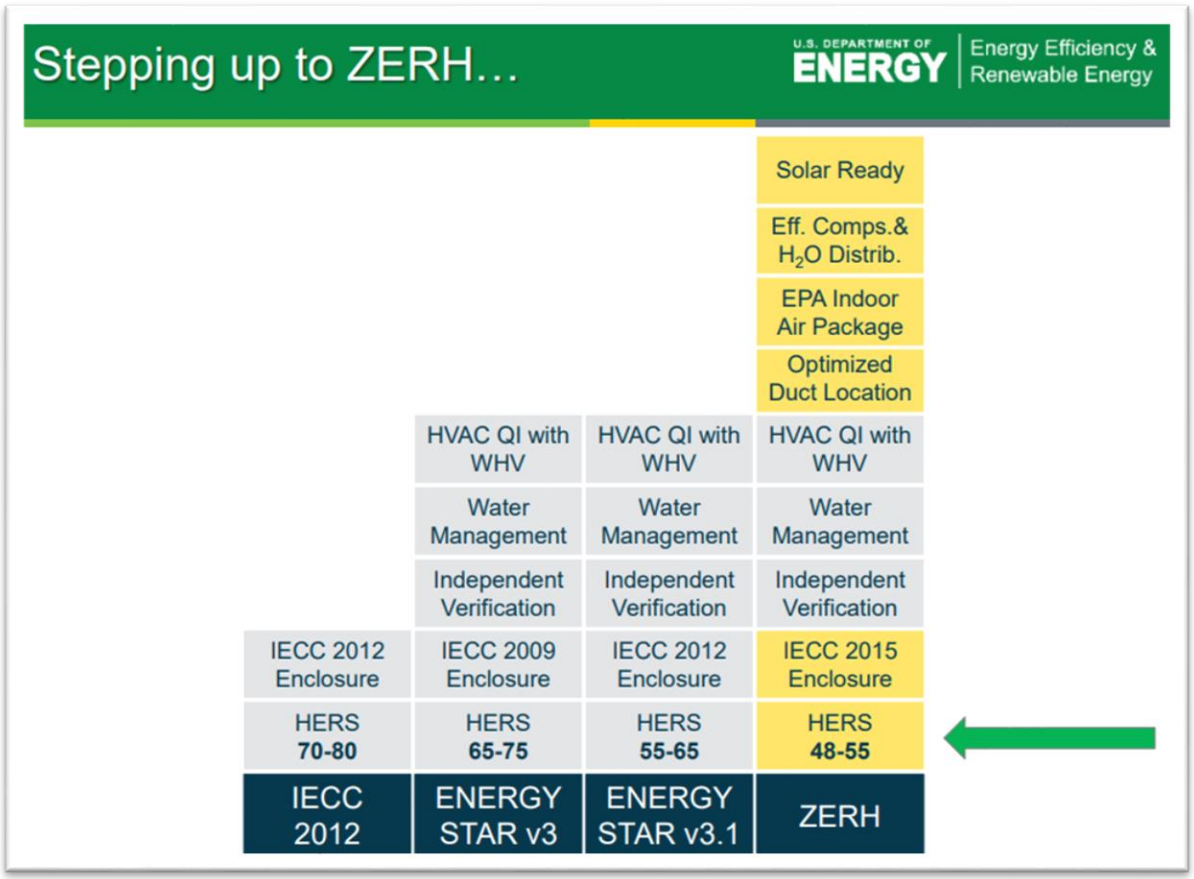
Total Unit Count	PSH requirement
32 units or greater	8% of total units
11-31 units	Minimum of 2 units
10 Units or less	Minimum of 1 unit

Compliance with fair housing always applies, tenants must have a lease in their name, and participation in services may not be a condition of tenancy.

HIEE Funds Criteria

Projects must meet or exceed the following performance requirements, and must submit their HERS rater plan review and preliminary rating, and their preliminary documentation of green build certification. Applications for which these documents are incomplete or missing will be considered ineligible for an award from this ASNH HIEE Supplemental Funding Round, and DHCD staff will advise applicants that they will need to resubmit documentation in conjunction with a completed application for the ASNH competitive loan pool at a later date.

Please note the minimum requirements differ substantially from Virginia Housing's Low-Income Housing Tax Credit (LIHTC) energy efficiency requirements. Meeting the LIHTC Qualified Allocation Plan energy-related standards or meeting EnergyStar standards do not qualify a project for HIEE funding.



Slide courtesy Newport Partners/Jamie Lyons from the ASNH Webinar: HIEE Requirements
Presentation recording available at dhcd.virginia.gov/hiee
Further information available at buildings.energy.gov

HIEE Minimum Energy Efficiency Performance Requirements	
New Construction	Green building certification required* Zero Energy Ready Homes (ZERH)**
Substantial Rehabilitation	Green building certification required* Average HERS index of 70 or below across all units OR 40% improvement in HERS index Additional requirements: ACCA Manual J calculations for heating/cooling loads Fresh air ventilation and dehumidification** Duct leakage testing and sealing*** Architect cost certification of upgrades needed to meet HIEE requirements
Adaptive Reuse	Green building certification required* Average HERS index of 80 or below across all units Additional requirements: ACCA Manual J calculations for heating/cooling loads Fresh air ventilation and dehumidification** Duct leakage testing and sealing*** Architect cost certification of upgrades needed to meet HIEE requirements

*Eligible green building certifications include: LEED, EarthCraft Gold or higher, National Green Building Standard Silver or higher, and Enterprise Green Communities.

**Dehumidification strategy/equipment shall provide for occupant comfort and health by maintaining interior RH in 40-60 percent range. For renovations and adaptive reuse projects, if building/unit envelopes are tightened to new construction standards (5 ACH_{50}), ventilation system(s) shall provide fresh air supply per the most current version of ASHRAE 62.1 or 62.2, or the most current version of USBC, whichever is more stringent.

***Existing ductwork shall be sealed and tested to be ≤10 percent total duct leakage; if HVAC system/ductwork will be newly-installed, duct leakage shall meet new construction energy code requirements (≤4 percent total duct leakage).

Additional Federal and State Requirements

Section 504

Section 504 applies to all ASNH assisted rental projects based on project type, which is determined by DHCD staff in coordination with the Applicant/Developer.

New Construction

New construction of multifamily rental housing with five or more units must be designed and constructed to be readily accessible to and usable by persons with disabilities. All common areas in the building must be made accessible, and a minimum of individual units must also be accessible.

- A minimum of five percent (5%) of the dwelling units in the project (but not less than one unit) must be accessible to individuals with mobility impairments.
- An additional two percent (2%) of the dwelling units (but not less than one unit) must be accessible to individuals with sensory impairments (i.e., hearing or vision impairments).

Rehabilitation: Substantial alterations

Multifamily rental projects of fifteen units or more that undergo "substantial alterations" must also comply with Section 504's accessibility requirements. Substantial alterations are defined as projects where costs of the planned rehabilitation will be seventy-five percent (75%) or more of the replacement cost of the completed facility. For these projects, all common areas in the building must be made accessible, and a minimum of individual units must also be accessible.

- A minimum of five percent of the dwelling units in the project (but not less than one unit) must be accessible to individuals with mobility impairments.
- An additional two percent, at a minimum (but not less than one unit), must be accessible to individuals with sensory impairments.

The requirements for multifamily projects undergoing substantial alterations are found at 24 CFR 8.23(a).

Rehabilitation: Other Alterations

If a multifamily rental project does not meet the definition of substantial alterations, the alterations that are made must, to the maximum extent feasible, make the dwelling units accessible to and usable by individuals with mobility impairments.

If alterations of single elements or spaces of a dwelling unit, when considered together, amount to an alteration of a dwelling unit, then the entire dwelling unit shall be made accessible to persons with mobility impairments. This would include alterations that involve certain kitchen and bathroom renovations, as well as entrance door jamb replacements. In addition, alterations to common spaces must make those areas accessible to the maximum extent feasible.

For this category of rehabilitation, only:

- When a minimum of five percent of the dwelling units (but not less than one unit) are accessible to people with mobility impairments, then no additional units are required to be made accessible
- There is no requirement to make any units accessible to individuals with sensory impairments.

A recipient is not required to make these accessibility alterations if doing so would impose undue financial *and* administrative burdens on the operation of the multifamily housing project (24 CFR 8.23(b)). However, projects in this category of rehabilitation may not be funded at DHCD's sole discretion when projects which do create additional accessible units are eligible within the same application round.

Program agreements will reflect Section 504 units, and will require that any vacant 504 units are listed on Virginia Housing Search and held for at least 60 days before being leased to household not requiring a unit-specific accommodation. Tenant selection plans must also include 504 units.

Fair Housing Act

The Fair Housing Act prohibits discrimination in the sale or rental of housing based race, color, religion, sex, national origin, handicap or familial status. This prohibition applies to all projects assisted with the ASNH program, and any project or applicant that discriminates or projects which are structured to discriminate are ineligible.

Lead Safe Housing

Lead Safe Housing policies apply to ASNH projects, unless they are found to be exempt. For non-exempt projects appropriate measures must be taken to assure that:

- Rehabilitation or demolition activities meet lead safe requirements;
- Development costs include associated costs;
- Homebuyers or tenants will receive notification (if applicable);
- Operating costs include ongoing associated maintenance costs for rental projects; and
- Records are maintained to document all measures taken.

Uniform Relocation Act (URA)

Accommodations for any relocations are required for all funding sources. However, the Uniform Relocation Act (URA) applies to all HOME/NHTF assisted projects where development activity will result in the permanent or temporary dislocation of households, businesses, farms and nonprofit organizations. When permanent or temporary dislocation is possible, a notice of the intent and a survey of the occupants must be conducted prior to the ASNH application. All application must include a completed URA Assessment Form and documentation of the notice and survey results. Development costs must reflect any associated costs that the project anticipates.

Section 3 Requirements

Section 3 requirements apply to all HOME/NHTF-assisted projects. These requirements mean that development-generated opportunities must be designed to benefit to the greatest degree possible low and very low income persons in the project services area and the business that employ them.

Developer hiring, contracting, and subcontracting must be structured to maximize this benefit. Project owner/developers are required to adopt specific goals, develop a Section 3 plan, and comply with required notifications, documentation, and reporting documented to DHCD through CAMS.

Labor Standards

Labor Standards apply to all projects. All projects must assure that workers receive "overtime" compensation at a rate of 1.5 times their basic rate of pay for all hours worked in excess of 40 hours a work week. This applies to all project associated construction contracts funding in whole or in part with HOME/NHTF resources.

Davis-Bacon Act and the Copeland "Anti-Kickback" Act requirements apply to projects with 12 or more HOME assisted units (determined in underwriting by DHCD, in part on the proportion of HOME funds to total development costs). In these cases, Davis-Bacon prevailing wages must be paid to workers at least weekly without any deductions or rebates except permissible deductions. Reporting requirements include the payroll submissions.

Violence Against Women Act

Violence Against Women Act applies to all projects and provides housing protection for survivors of domestic and date violence, sexual assault, and stalking. This requirement requires that all tenants are notified of their rights under the provision. The provision allows for emergency transfers to other units, bifurcation of leases, protection against denials, evictions, and terminations that directly result from being a victim, and allow for a low-barrier certification process.

Environmental Review

All applicants must complete and submit with their application a Phase 1 Environmental Site Assessment. In addition, as stated in the HOME and NHTF Criteria sections above, compliant environmental review must be completed before DHCD can execute any HOME or NHTF Program Agreement to secure a formal commitment of funds.

It is essential that developers not proceed with any project activity (e.g., acquisition, rehabilitation, demolition, construction, etc.) prior to the execution of the program agreement or the project will likely be rendered ineligible for funding. Applicants must allow sufficient time to complete and submit all required environmental site assessment documentation to DHCD.

Coordination on the environmental review procedure is required if combining ASNH resources with CDBG or other federal funding such as local HOME. Part 58 checklists must be submitted within six months of a HOME or NHTF award being made, and prior to any potentially choice limiting activities being undertaken.

Application Submission and Evaluation

All applications for Affordable and Special Needs Housing (ASNH) must be submitted through DHCD's Centralized Application and Management System (CAMS) prior to the application submission deadline.

The deadline for Fall 2022 submissions is October 31, 2022 at 11:59pm
CAMS automatically closes the application to submissions at this time.

The CAMS User Guide provides information and instructions on setting up and managing a CAMS account, and should be used first to troubleshoot any errors. Please allow up to two business days for responses to any CAMS Help Desk request. DHCD technical assistance is limited to normal business hours.

ASNH Application Instructions are available in CAMS to further assist Applicants in completing and submitting applications for ASNH funds. Applications submitted with incorrect or missing information will be reviewed *as is,* and may be ruled ineligible.

DHCD conducts panel reviews of all Applications submitted in CAMS prior to the submission deadline. During this panel review, the Application is first screened to ensure the Project and Applicant meet the eligibility requirements. Projects or Applicants which do not meet eligibility requirements are not provided with a numerical score.

Applicants with outstanding or unresolved findings from audit or monitoring findings, unresolved IRS findings, unresolved compliance findings – including those issues which may be identified to DHCD by another previous partner such as Virginia Housing (VH or VHDA) –, or which are not in compliance with previous DHCD agreements will not be eligible for a funding commitment for any Project until such findings and/or compliance issues are resolved. DHCD staff are committed to working with any interested party to develop a plan for resolution and restoration of eligible status.

Scoring Criteria

Applications are scored on a one hundred (100) point scale, and Projects must score sixty (60) points or higher to be qualified for funding.

Scoring criteria are as follows

- Need – 40 points
    - The Applicant demonstrates through narrative responses and information in attachments that the Project fills a critical need in the market area.
    - For rental projects only, PSH projects receive points (5) in this category
    - For HOME funds only, projects in non-Entitlement or non-Consortium localities receive points (5) in this category

- Feasibility – 30 points

    - The Applicant demonstrates through narrative responses and information in attachments that the Project is likely to come to a timely completion

- Developer Capacity – 30 points
    - The Applicant demonstrates through narrative responses and information in attachments that the development team has the ability to successfully complete projects and deliver affordable housing
    - For HOME funds only, CHDO-involved projects receive points (5) in this category

DHCD staff will rank all qualified Applications based on score. The highest scoring Applications from each round will received offers of funding from DHCD, up to the amount requested in the Application as available based on per-project and per-source caps, and remaining funds for allocation through the ASNH Program. These offers are preliminary awards and are contingent upon the Applicant meeting certain requirements as outlined in the Program Guidelines and in the source-specific letter of award offer.

DHCD reserves the right to retain any funds offered during an application cycle or program year as unallocated, and such unallocated funds will carry forward to future application cycles and program years as allowed.

Notification of Funding Decision

The Office of the Governor of Virginia makes the Affordable and Special Needs Housing program funding award announcements public, typically by the publication of a press release.

After the ASNH Program application cycle closes, ASNH staff are unable to answer inquiries as to the timing or contents of this announcement. Any such inquiries will not be returned.

After the public announcement of ASNH Program awards, DHCD staff will send an email to the Project Primary Contact as listed for each Project in CAMS containing either a notification of awarded funds or a denial of funding. Projects which are denied funding may request to schedule a technical assistance call, or *debrief*, with ASNH staff to discuss comments or feedback on the Application.

Execution of Award Terms

Applicants receiving a notification of awarded funds for Projects are considered preliminarily qualified. For each source awarded, the notification of awarded funds is comprised of two documents. The first document is a letter of award, which will be signed by the Senior Deputy Director of Community Development and Housing.

The second document will contain additional terms of the awarded funds, including interest rate, length of affordability period, and details program requirements (including environmental review processes). This *terms letter* must be countersigned by the Applicant and returned to DHCD staff prior to the issuance of a Program Agreement.

DHCD's expectation is that all Applicants requesting ASNH funds are prepared to return executed *terms letter(s)* in a timely manner. Applicants which delay the return of an executed terms letter without communicating with their assigned Program Administrator may not be eligible for an extension of time to complete the Program Agreement.

Execution of Program Agreement(s)

Applicants have a maximum twelve (12) months from the date on the notification of awarded funds and *terms letter(s)* to complete all program requirements and execute the Project's Program Agreement. This window of time is intended to allow both Applicants and DHCD to complete necessary processes which may have predetermined time requirements, such as Applicant underwriting review or DHCD public notice and comment periods.

The Program Agreement (a formal commitment of funds, and prerequisite for a legal loan commitment for rental projects or prerequisite to Deeds of Trust and remittance eligibility for homeownership projects.) Program requirements vary by source, but may include an environmental review process with public comment periods as required by HUD, and program agreements cannot be issued until all contingencies and program requirements are met.

ASNH Program Agreements generally expire two years from the date of execution, by which time the Project should be completed and ready to schedule permanent conversion or closing (rental projects) or should be completed and ready to submit closing disclosures on final home sales (homebuyer projects). Written requests for extensions of any deadline above must be received by DHCD prior to the expiration of the agreement or commitment, and are approved on a case-by-case basis at DHCD's discretion.

Marketing Materials

DHCD and the specific funding source(s) must be including on all marketing materials to include press releases, the project website, and signage. DHCD requires that a project sign be installed within thirty (30) days of the execution of the Agreement. Please see signage requirements for more details.

Appendix A – HOME Consortiums & Entitlements

Projects in these localities must provide evidence of matching funds as detailed in the Program Guidelines to be eligible for an award of HOME funds from the ASNH Program.

HOME Consortiums

Charlottesville Consortium
- Albemarle County
- Charlottesville
- Fluvanna County
- Greene County
- Louisa County
- Nelson County

New River Consortium
- Blacksburg
- Christiansburg
- Giles County
- Montgomery County
- Pulaski County
- Radford

Suffolk Consortium
- Franklin City
- Isle of Wight
- Southampton
- Suffolk

Winchester Consortium
- Clarke County
- Frederick County
- Page County
- Shenandoah County
- Warren County
- Winchester

HOME Entitlements

Alexandria
Arlington County
Bristol City (TN Consortium)
Chesapeake
Chesterfield County
Danville
Fairfax County, including
- Fairfax City
- Falls Church

Hampton
Henrico County
Lynchburg
Newport News
Norfolk
Portsmouth
Prince William County, including
- Manassas
- Manassas Park

Richmond
Roanoke City
Virginia Beach

Appendix B – HIEE Minimum Energy Efficiency Performance Requirements

HIEE Minimum Energy Efficiency Performance Requirements	
New Construction	Green building certification required* Zero Energy Ready Homes (ZERH)**
Substantial Rehabilitation	Green building certification required* Average HERS index of 70 or below across all units OR 40% improvement in HERS index Additional requirements: ACCA Manual J calculations for heating/cooling loads Fresh air ventilation and dehumidification** Duct leakage testing and sealing*** Architect cost certification of upgrades needed to meet HIEE requirements
Adaptive Reuse	Green building certification required* Average HERS index of 80 or below across all units Additional requirements: ACCA Manual J calculations for heating/cooling loads Fresh air ventilation and dehumidification** Duct leakage testing and sealing*** Architect cost certification of upgrades needed to meet HIEE requirements

*Eligible green building certifications include: LEED, EarthCraft Gold or higher, National Green Building Standard Silver or higher, and Enterprise Green Communities.

**Dehumidification strategy/equipment shall provide for occupant comfort and health by maintaining interior RH in 40-60 percent range. For renovations and adaptive reuse projects, if building/unit envelopes are tightened to new construction standards (5 ACH_{50}), ventilation system(s) shall provide fresh air supply per the most current version of ASHRAE 62.1 or 62.2, or the most current version of USBC, whichever is more stringent.

***Existing ductwork shall be sealed and tested to be ≤10 percent total duct leakage; if HVAC system/ductwork will be newly-installed, duct leakage shall meet new construction energy code requirements (≤4 percent total duct leakage).

Appendix C – Eligible Costs

For all project types, all funded development costs must be allowable:

Eligible or Allowable Costs:

- *Demolition cost*s are eligible costs, however construction must begin within 12 months
- Construction, labor, and materials costs
- Project development costs (e.g., financing fees, legal fees, affirmative action marketing)
- Up to 18 months rental project operating deficit reserve
- Relocation costs for any household in project as a part of the project development costs

Ineligible Costs:

- HOME/NHTF investments not resulting in HOME/NHTF eligible units
- Project reserves other than the rental operating (above) or beyond 18 months
- Costs for the development, operation, or modernization of any public housing
- Some specific costs related to RAD (Rental Assistance Demonstration) projects
- Items not allowed under 2 CFR 200 or not deemed cost-reasonable
- Project-based rental assistance
- Delinquent taxes, fees, charges

Appendix D – Additional Program Requirements and Compliance

Rental Projects

While final cost certification and completion reports are required at closing, progress reports may be required quarterly on each project during the development phase, and regular construction inspections may be conducted to verify progress.

Affordability periods begin after permanent conversion (DHCD loan conversion) when all closing checklist items (which may include but are not limited to completion reports, including lease up data or rent rolls, HUD-required demographic data as determined by source) are provided to DHCD for review and approval.

Assisted units have income restrictions as detailed in the Program Guidelines, with initial certification and annual recertification required. HOME- and NHTF-assisted units also have HUD-determined rent limits. Rents cannot exceed these HUD-determined rent limits, with the exception of project-based rental assistance. Rent increases over those proposed in the project application must be approved by DHCD.

The Compliance in HOME Rental Projects: Guide for Property Owners and HOME Rental Compliance Training provide more detail on income and rent requirements; Additional requirements will be detailed in an individual project's program agreement and loan commitment documents.

Long-Term Compliance

During the affordability period each project will be required to submit annual rent and occupancy reports and project financials. DHCD will verify through onsite monitoring compliance with rent, occupancy, property standards, and other programmatic requirements. **Non-compliance may suspend eligibility for subsequent commitments and could result in the repayment of all funds to DHCD.**

Projects will be inspected for property standards and program compliance within 12 months of project completion. Projects will be inspected thereafter no less than every three years. All rental projects must submit annual rent and occupancy reports and project financials. Onsite inspections and monitoring frequencies are based on performance and risk assessments.

Rental projects must meet program rent, occupancy, and property standards and other applicable federal or state requirements for the duration of the affordability period in accordance with the program agreement. Additional HOME/NHTF program investments cannot occur during this time period. Projects unable to meet these requirements or projects at-risk of non-compliance may be required to submit to more frequent monitoring, to change property management, and/or transfer ownership.

Homebuyer Projects

Project Completion

While final cost certification and completion reports are required at the end of the development phase and prior to the last reimbursement remittance or draw, progress reports may be required quarterly on each project during the development phase, and regular construction inspections may be conducted to verify progress.

For homebuyer developments assisted with any ASNH source, the final reimbursement remittance or draw (typically 10% of the total award) will not be approved until all completion documentation is submitted and approved by DHCD. Completion documentation required may include the COs for all properties named on the deed of trust by DHCD, and covered by the deferred loan agreement between the Applicant and DHCD, closing disclosures and lien documentation from each sale, and completion reports such as the HUD HOME Homebuyer Set Up/Completion report. **Non-compliance could suspend eligibility for additional funds and could result in the repayment of all funds to DHCD.**

HOME-assisted homebuyer developments automatically convert to HOME rental units for the duration of the affordability period if there if there is no ratified sales contract at nine months after the date a Certificate of Occupancy is issued to the project. HUD allows no exception to this requirement.

Value or Sales Limits

Homebuyer properties must be considered *modest*, based on property sales price or value. The sales price cannot exceed 95% of the median area purchase price, using HUD 203 (b) limits or a local market survey. No luxury homes or amenities as determined by neighborhood standards are allowed for assisted units.

Lease-Purchase Projects

Homebuyer projects may be structured as lease-purchase projects, but must be identified as lease-purchase in the application. Lease-purchase projects must convert to a tenant-purchased homebuyer unit within three years. Any units which failing to meet this requirement will convert to HOME rentals unit for the duration of the affordability period. Applicants considering this option **are required** to consult with DHCD prior to submitting an application for a project.

Resale Requirement: Homebuyer Developer Subsidy Projects

Homebuyer units assisted through developer subsidy are subject to a resale provision. A resale provision requires the assisted unit to be resold to an income eligible household if the original purchaser chooses to sell their home prior to the end of the applicable affordability period.

The developer must monitor sales, foreclosures, and title transfers to assure affordability requirements. The developer must ensure that resale requirements are imposed if the housing does not continue to be the principal residence of the occupant or family for the duration of the period of affordability, and must also ensure that the housing is only made available for subsequent purchase to a buyer whose family household qualifies as a low-income family and will use the property as its principal residence.

The resale requirement must also ensure that the price at resale provides the original assisted owner a fair return on investment, which is can be *additional* amount calculated to return, based on the homeowner's original cash/equity investment in the property and any capital improvement made to the property. This calculation limit also ensures that the housing property will remain affordable to a reasonable range of qualified low-income homebuyers for the full period of affordability as determined by DHCD according to the amount of funds invested in the housing.

A "fair return on investment*"* is determined by the resale price that takes into account a return of the initial homebuyer's initial investment plus any capital improvements made to the housing unit, which are typically set or limited based on changes in area median sales price. These factors typically establish the fair market value for the city or county that the property is located. The intent is to provide a fair return to the seller while limiting price based solely on the Median Sales Price to a potential buyer.

To determine a *"*a fair return on investment*"*, the ASNH Program will measure the percentage change in median sales prices over the period of ownership as a reasonable index that is directly related to real estate prices in the area which will simplify the resale approach by taking both market appreciation and depreciation into account. It is important to note that in certain circumstances, such as a declining housing market where home values are depreciating, the original homebuyer may not receive a return on his or her investment because the home sold for less or the same price as the original purchase price. DHCD's intent is to set a resale price that provides a fair return to the original homebuyer while ensuring that the property is affordable to the target population, thus reducing the need for additional subsidies to eligible buyers.

A capital improvement is any addition or alteration to real property that meets the following conditions:

- It substantially adds to the value of the real property, or appreciably prolongs the useful life of the real property; and
- It becomes part of the real property or is permanently affixed to the real property so that removal would cause material damage to the property or article itself.

The value of any capital improvement will be determined by the national average increase in value that a specific type of improvement brings at sale. For example, if homeowner's down payment was $5000, the value of capital improvements is $9000 and the percentage change of median sales price over ownership period was 3.5%, then a calculation of ($5000 + $9000) x 3.5= $490. The fair return on investment is $490, and the total return to the original homebuyer at resale would not exceed $14,490 ($5000 + $9000 + $490).

A *"reasonable range of low-income buyers"* is defined in the ASNH Program as a household or family at or below 80 percent of Area Median Income paying no more than 30 percent of income for principal, interest, property taxes, and insurance.

DHCD will use deed restrictions, covenants running with the land, or other similar mechanisms as the mechanism to impose the resale and continued affordability requirements as outlined in §92.254(a)(5)(i)(A) of the HOME Rule. The developer may use purchase options, rights of first

refusal or other preemptive rights to purchase the housing before any conveyance to preserve affordability. The affordability restrictions shall be revived according to the original terms if, during the original affordability period, the owner of record before the termination event, obtains an ownership interest in the housing.

Recapture Provision: Direct Homebuyer Assistance

ASNH Homebuyer HOME-assisted units including DHCD HOME Down Payment Assistance (DPA) direct buyer assistance are subject to a recapture provision in order to assure that the units either remain affordable (i.e., housing eligible clients) or that DHCD recovers its investment based on the terms of the agreement. Recapture applies and the amount to be recaptured is limited to the amount of direct buyer assistance (not the developer subsidy).

Virginia will use the recapture provision at §92.254(a)(5)(ii))1) to recapture the entire amount. The total original amount of the direct buyer assistance is recaptured from the net proceeds in the case of sale, refinance (see exception below), foreclosure or failure to maintain as primary residency prior to the end of the affordability period. In these cases the required amount returned (total assistance amount from net proceeds) is due and payable in full to DHCD to the Treasurer of Virginia.

The assistance may not be subordinated to refinancing of the first lien position primary mortgage or an equity loan or line of credit during the period of affordability except under special hardship conditions at DHCD's discretion. Affordability requirements are secured by a Restricted Deed of Covenant in the amount of direct assistance. The loan is forgiven in full at the end of the affordability period.

Attachment 59

INVESTING IN VIRGINIA THROUGH ENERGY EFFICIENCY: AN ANALYSIS OF THE IMPACTS OF RGGI AND THE HIEE PROGRAM

JANUARY 2023

VCU L. Douglas Wilder School of Government and Public Affairs

Investing in Virginia through Energy Efficiency: An Analysis of the Impacts of RGGI and the HIEE Program

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ABOUT THE WILDER SCHOOL

The L. Douglas Wilder School of Government and Public Affairs at Virginia Commonwealth University informs public policy through cutting-edge research and community engagement while preparing students to be tomorrow's leaders. The school's Center for Public Policy aims to advance research and training that informs public policy and decision-making to improve our communities.

ABOUT URBAN AND REGIONAL STUDIES AND PLANNING AT VCU

Urban and Regional Studies and Planning (URSP) is an academic unit within the L. Douglas Wilder School of Government and Public Affairs at Virginia Commonwealth University, offering a Bachelors of Urban and Regional Studies and a Masters of Urban and Regional Planning (MURP). Its mission is to educate students to think critically, apply technical and methodological skills, engage with diverse viewpoints, and contribute positively to civic life.

ABOUT THE INSTITUTE FOR SUSTAINABLE ENERGY AND ENVIRONMENTS

The VCU Institute for Sustainable Energy and Environments (ISEE) was formed in 2022 to pursue innovative scientific, technological, policy and social justice solutions addressing the climate and energy crisis. This includes innovations in clean, secure and energy efficient systems, carbon capture and other mitigation strategies, sustainable ecosystems, and environmental justice. The goals of the Institute are to disseminate knowledge on sustainable energy and environments through patents and commercialization, publications, community outreach, engagement with policymakers and pedagogy.

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Frequently Used Acronyms

ACEEE: American Council for an Energy Efficient Economy

AMI: Area Median Income

APCO: Appalachian Power Company

ASNH: Affordable and Special Needs Housing

BIL: Bipartisan Infrastructure Law (i.e., the federal Infrastructure Investment and Jobs Act)

BTU: British Thermal Units

DHCD: Virginia Department of Housing and Community Development

DOE: U.S. Department of Energy

EERE: Office of Energy Efficiency & Renewable Energy (part of U.S. Department of Energy)

EIA: U.S. Energy Information Administration (part of U.S. Department of Energy)

FPL: Federal Poverty Level

GTSA: Grid Transformation and Security Act

HIEE: Housing Innovations in Energy Efficiency

IRA: Inflation Reduction Act

KWH: Kilowatt-hours

LEAD: Low-Income Energy Affordability Data tool

LIHEAP: Low-Income Home Energy Assistance Program

LIHTC: Low-Income Housing Tax Credit

MWH: Megawatt-hours

NREL: National Renewable Energy Laboratory

RECS: Residential Energy Consumption Survey (U.S. Department of Energy)

RGGI: Regional Greenhouse Gas Initiative

SCC: State Corporation Commission

VCEA: Virginia Clean Economy Act

VHDA: Virginia Housing Development Authority (aka Virginia Housing)

WAP: Weatherization Assistance Program

Executive Summary

This study examines the low-income energy efficiency programs funded by Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI). Its goal is to understand the extent to which those programs can address the problem of high energy burdens among Virginia's low-income residents, and to estimate the impacts that those energy efficiency investments could have on the broader Virginia economy.

Our report begins with a review of existing research on "energy burdens," or the concept that some residents, particularly those in lower income brackets, spend a disproportionate percentage of their incomes on home energy costs (heating, cooling, etc.). We then discuss the potential to relieve those burdens through investments in energy efficiency, and summarize some of the federal and state-level policies and programs that support energy efficiency and "weatherization" for low-income households.

We then present our original analysis for this study, which includes the following components:

- A series of maps that evaluate the spatial distribution of low-income energy burdens in Virginia
- A projection of potential future RGGI revenue for Virginia (high and low scenarios) through 2030
- An analysis of the potential energy efficiency benefits from the two RGGI revenue scenarios, including the number of housing units that could be upgraded and the resulting energy consumption reductions and customer bill savings
- An analysis of the broader economic impacts that would result from these RGGI-funded energy efficiency investments, including total economic impact, value added, and jobs created

Some of the more notable findings from our analysis are as follows:

- Average energy burdens for low-income households are at or above the 10% threshold for "Severe" energy burden across much of Virginia, particularly in rural areas.
- Virginia's metro regions have lower low-income energy burdens on average, with some exceptions in in parts of Hampton, Newport News, Norfolk, Portsmouth, and Richmond
- Virginia has approximately 579,000 low-income households located in Census tracts with a High average low-income energy burden (above 6%), and about 154,000 low-income housing households in Census tracts with a Severe average low-income energy burden (above 10%).
- If Virginia continues to participate in the RGGI program through 2030, the estimated total revenue over the decade (2021-2030) will be in the range of $2.5 - $3.3 Billion, resulting in between $125 - $165 million per year for low-income energy efficiency programs.
- This estimated revenue from the RGGI program far exceeds the total funding otherwise available for low-income energy efficiency via existing state and federal programs.
- These RGGI funds could provide energy efficiency upgrades to up to 130,000 homes in the High revenue scenario, leading to over 590,000 MWh in annual electricity reductions and $89 million in annual customer bill savings, for an average of $676 in annual energy savings per household.
- The expenditure of these RGGI energy efficiency funds would have a statewide economic impact of between $2.03 billion and $2.67 billion over the course of the decade (2021-2030), including up to $1.75 billion in Value Added, and would create and sustain up to 2,115 new jobs.

Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) program has generated over $250 million for low-income energy efficiency programs over the past two years (2021-2022). These funds, passed through the Department of Housing and Community Development's (DHCD) Housing Innovations in Energy Efficiency (HIEE) program, support energy-efficiency upgrades in two ways:

- Provide funding to include highly energy-efficient features in new and rehabilitated affordable multi-family housing developments, via the DHCD's existing Affordable and Special Needs Housing Program (ASNH-EE)
- Fund repairs to homes that have been deemed unsuitable for weatherization, via the DHCD's new Weatherization Deferral Repair (WDR) program, thus allowing those homes to gain access to federal Weatherization Assistance Program (WAP) dollars

The $125 million per year that Virginia's participation in RGGI has provided for the HIEE program thus far dwarfs all other low-income energy efficiency programs operating in the state, which are anticipated to provide less than $55 million per year combined over the next few years. This includes about $17.25 million from the federal Low-Income Home Energy Assistance Program (LIHEAP), which primarily provides bill relief but also supports low-income weatherization, and about $13 million a year in WAP funding. Both of these totals include recent short-term funding increases resulting from the 2021 passage of the federal Infrastructure Investment and Jobs Act. The $55 million total also includes the $15 million a year that Dominion Energy and Appalachian Power (APC) are required to spend on low and moderate income (LMI) energy efficiency programs under the provisions of the Grid Transformation and Security Act (GTSA) and the Virginia Clean Economy Act (VCEA). Finally, this total includes an additional $6 million per year from Dominion's Energy Share program, plus low-income energy efficiency investments from Virginia's natural gas utilities, which are believed to total less than $4 million.

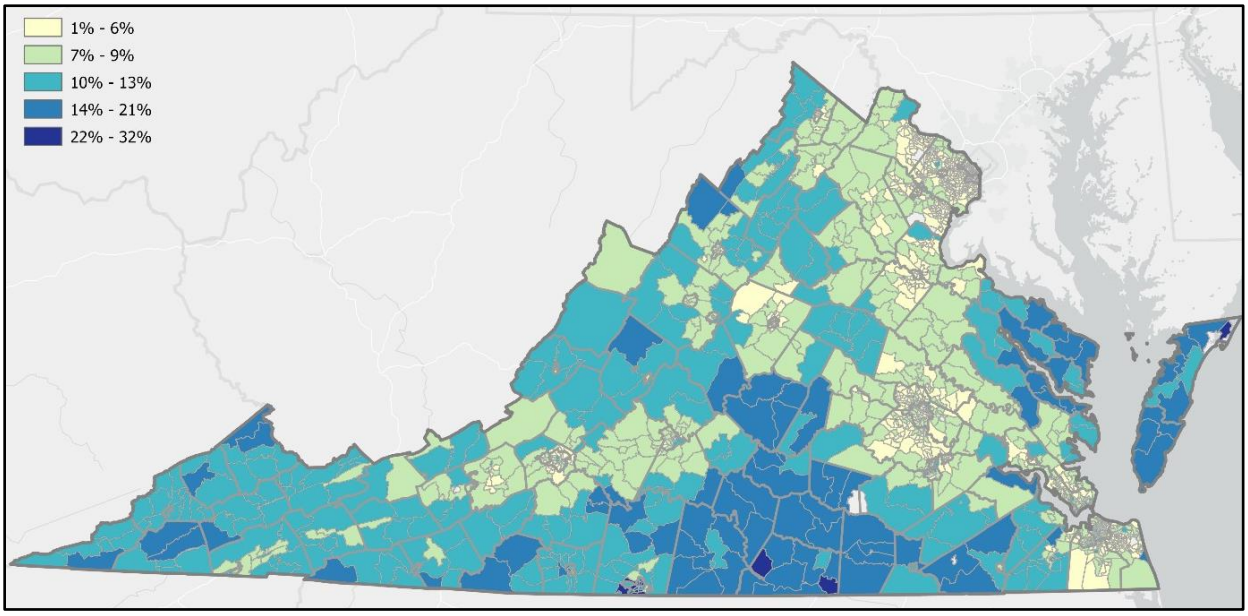
The Challenge of Low-Income Energy Burdens in Virginia

This substantial increase in low-income energy-efficiency funding will go a long way towards addressing the significant "energy burden" problems facing many of Virginia's low-income residents. According to data from the U.S. Department of Energy (DOE), low-income households in Virginia – defined as those earning less than 80% of the Area Median Income (AMI) – spend about 7% of their income on home energy costs (heating, cooling, etc.). This exceeds the 6% threshold that constitutes "High" energy burden. Extremely-low-income households in Virginia (incomes of 0-30% AMI) have an average energy burden of 17%, which is well above the 10% threshold for "Severe" energy burden and more than eight times the 2% average for households with incomes above 80% AMI.

Energy burden is not only a function of income. Low-income households tend to live in less-efficient housing units, have less-efficient appliances, etc., which leads them to spend more on household energy costs (per square foot) compared to non-low-income households. This leads to higher rates of "energy insecurity," in which households react to high energy burdens by reducing their food and/or medical expenditures and/or resort to dangerous coping mechanisms, such as leaving their homes at unhealthy temperatures or using ovens and space heaters to heat their homes.

While low-income energy burdens are a challenge throughout Virginia, they are particularly acute in certain regions. We evaluated these regional disparities, using data from the Census Bureau and the DOE's Low-Income Energy Affordability Data (LEAD) Tool, to produce a series of maps found in Section 3. The first of these maps, shown here as Figure ES-2, demonstrates the average energy burden by Census tract for households with incomes below 80% AMI.

Figure ES-1. Map of Average Energy Burden of Low-Income Households by Census Tract



Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

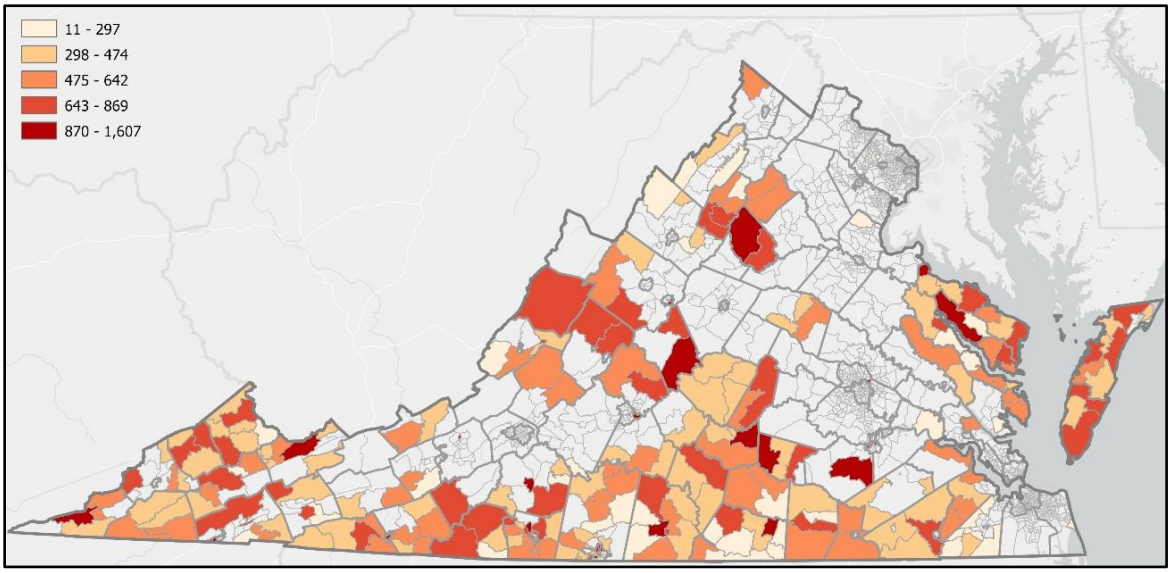
The map above shows that average energy burdens for low-income households are at or above the 10% threshold for Severe energy burden across much of Virginia's rural areas. This is particularly the case in Southwest Virginia, Southside Virginia, the Northern Neck, and the Eastern Shore.

Average low-income energy burdens are generally lower in the state's metro regions. However, Map 1.A. in Section 3.1 shows that concentrations of High to Severe low-income energy burden are found in some urban areas, particularly in parts of Hampton, Newport News, Norfolk, Portsmouth, and Richmond.

Our research also identified some pockets of extreme low-income energy burden. There are 76 Census tracts in Virginia where the average energy burden for low-income households is at or above 15%, or more than twice the national average for households in the 0-80% AMI range. Twelve of those tracts are in the Danville area. There are also 15 Census Tracts in Virginia where the average low-income energy burden is at least 22%, or more than double the threshold for Severe energy burden.

We then mapped the number of housing units within each of the Census Tracts that have average low-income energy burdens exceeding the High and Severe energy burden thresholds, with the latter shown in Figure ES-2 below. Additional housing unit maps are found in Section 3.1 and Appendix C.

Figure ES-2. Housing Units in Census Tracts with Severe Low-Income Energy Burden



Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

The map above demonstrates the total housing units in each of Virginia's Census Tracts where the average energy burden for low-income households exceeds the 10% threshold for Severe energy burden. Like the map shown in Figure ES-1 above, this map demonstrates that many of the low-income households facing Severe energy burdens are found in the state's rural areas, particularly in Southwest Virginia, Southside Virginia, the Northern Neck, and the Eastern Shore.

Section 3.1 includes zoomed in maps of the state's metropolitan regions, which demonstrate some concentrations of High average energy burden for low-income households in urban areas, but very few Census Tracts in which low-income households have a Severe average energy burden.

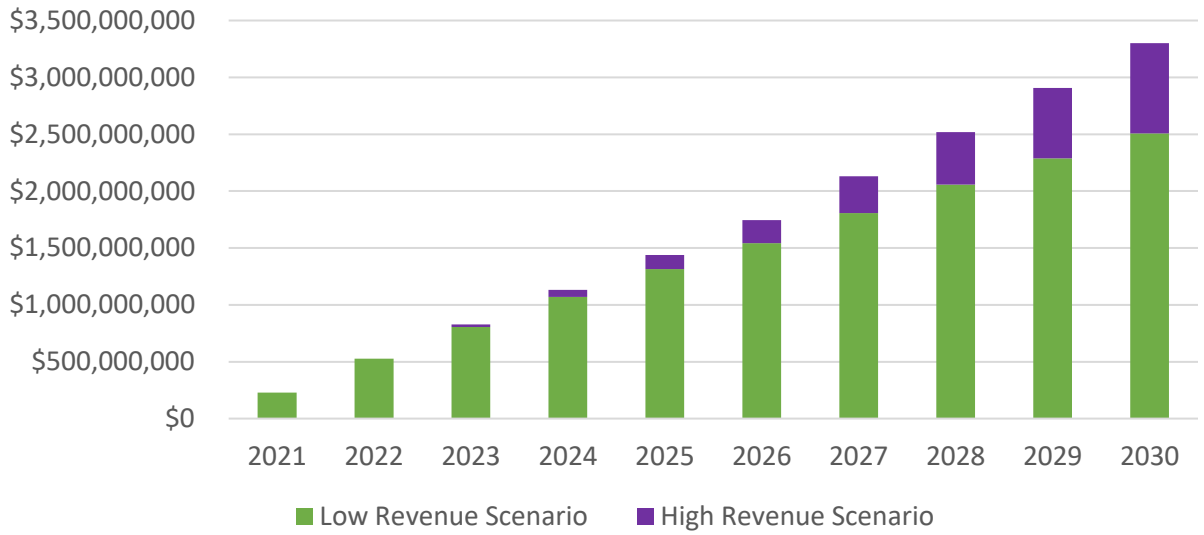
Addressing Virginia's Energy Burden Challenge via RGGI-Funded Energy Efficiency Programs

Energy efficiency is a powerful tool for reducing energy burdens and energy insecurity. Data from the National Renewable Energy Laboratory (NREL) shows that energy efficiency improvements could reduce low-income household electricity use in Virginia by roughly 30%, which is a higher rate than all but five other states. Numerous other studies, from NREL and other sources, have demonstrated the vast potential for reducing low-income energy consumption and energy burdens via cost-effective energy efficiency solutions, as discussed further in Section 1.2 of this report.

However, low-income households face a variety of challenges when it comes to actually realizing these benefits, most significantly the upfront costs of investing in energy efficiency upgrades. Additionally, while a variety of tax credits and other financial incentives are available from the federal, state, and some local governments, utilizing these programs still requires some element of up-front investment. This is why programs that directly provide energy efficiency upgrades to qualifying homes, such as those under Virginia's HIEE program, are particularly important for addressing low-income energy burdens.

If Virginia continues to participate in the RGGI program through 2030, we estimate that the combined total revenue over the decade (2021-2030) will be in the range of $2.5 - $3.3 Billion, as shown in Figure ES-3 below. (A detailed discussion of the RGGI program, the mechanisms by which it raises revenue for Virginia, and our projections of future RGGI revenue is provided in Section 4 of this report).

Figure ES-3. Projected Virginia RGGI Revenue, Low vs. High Scenarios, 2021-2030



Source: VCU analysis of RGGI auction revenue trends and policies

As the Clean Energy and Community Flood Preparedness Act requires 50% of the state's RGGI revenue to be spent on low-income energy efficiency improvements, the total funding to HIEE or other similar programs would be about $1.25 - $1.65 Billion, or about $125 - $165 Million per year on average.

The DHCD created the Housing Innovations in Energy Efficiency (HIEE) program as the entity to manage and distribute these RGGI energy efficiency funds, according to the following objectives:

- Deep energy retrofits (exceeding energy code requirements) that complement existing affordable housing construction and rehabilitation incentives, to ensure lowest income population benefits from long-term cost savings;
- Incorporate innovative approaches that will overcome traditional barriers to building and retrofitting affordable housing at scale;
- Prioritize long-term sustainability/durability and occupant health (e.g. preventing moisture issues, improving ventilation) along with energy efficiency upgrades

The DHCD has approved about $37 million in ASNH-EE and WDR expenditures thus far, leading to weatherization and energy efficiency improvements for nearly 4,000 Virginia homes since July 2021. The DHCD has also announced the release of an additional $80 million in ASNH-EE funds, which could support up to 6,500 more highly energy-efficient multi-family units.

One of the goals of this research project was to estimate the potential number of housing units that could receive energy efficiency upgrades via these HIEE programs, assuming that Virginia remains in RGGI and continues to distribute the funding in a manner similar to the first two years. We then sought to estimate the amount of reduced energy consumption and resulting customer bill savings that would result from those energy efficiency investments.

To create these estimates, we relied on publicly available data from DHCD to estimate the average cost per housing unit for the WDR and ASNH-EE programs, which we then used to calculate the estimated number of units that could be upgraded via each program with continued RGGI / HIEE funding. For the WDR program this included separate average costs for single-family homes (SFH) and multi-family housing units (MFH). The results of this analysis are shown in Table ES-1 below.

Table ES-1. Estimated Units Upgraded via HIEE Programs, per 2021-2030 Revenue Scenario

Revenue Scenario	ASNH - EE	WDR - SFH	WDR - MFH	Total Units
Low ($1.24 billion)	78,373	10,806	11,653	100,832
High ($1.64 billion)	101,833	14,041	15,141	131,015

Source: Calculations by authors

Next, we estimated the total annual energy savings from the housing units receiving energy efficiency upgrades in each RGGI revenue scenario. For this step we used data from the Virginia Center for Housing Research at Virginia Tech, which completed a study of the HIEE program for DHCD in the fall of 2022. The Virginia Tech researchers calculated the average annual energy savings per unit for each of the three types of energy-efficiency upgrades funded by the HIEE program: WDR – single-family; WDR – multi-family, and ASNH-EE. We then multiplied those averages times the housing unit totals shown in Table ES-1, to get the total estimated annual energy and customer bill savings shown in Table ES-2.

Table ES-2. Total Units Upgraded (2021-2030) and Annual (Year 2030) Energy and Bill Savings

RGGI / HIEE Revenue Scenario	Units Upgraded	Total Energy Savings (MMBTU)	Total Energy Savings (MWH)	Total Bill Savings ($Millions)	Bill Savings / Unit ($)
Low ($1.24 billion)	100,832	1,551,322	454,666	$68.20	$676
High ($1.64 billion)	131,015	2,015,703	590,769	$88.62	$676

Source: Calculations by authors, using energy savings data from Virginia Center for Housing Research

To clarify, the energy and customer bill savings shown in Table ES-2 are based on the total number of housing units that could receive energy efficiency upgrades via our estimated HIEE revenue scenarios. These are annual values, representing the projected energy and customer bill savings benefits in the year 2030, based on a projected electricity rate of $0.15 / kWh in the year 2030, as a result of the energy efficiency investments funded by HIEE from 2021-2030. These annual energy savings would continue beyond 2030, with corresponding customer bill savings. Annual energy and customer bill savings realized in the preceding years of the HIEE program (i.e., 2021-2029) would be proportional to the number of energy efficiency projects completed by that time.

Analyzing the Economic Impacts of Virginia's RGGI-Funded Energy Efficiency Programs

In the final stage of this project we created an economic impact model to evaluate how the change in economic activity from Virginia's RGGI-funded energy efficiency investments would impact the broader regional economy. We used IMPLAN, an industry standard for this type of input-output modeling.

The primary result of this analysis is that the expenditure of HIEE funds – $1.24 to $1.64 billion from 2021 through 2030 – would have a statewide impact of between $2.03 and $2.67 billion.

In other words, every dollar spent by the HIEE program generates a total impact of $1.66 – the original $1.00 ("direct impact"), plus another $0.66 generated through indirect and induced impacts. "Indirect impacts" are the dollars from the original expenditures that go to suppliers inside Virginia, while "induced impacts" occur when workers receive income from this new economic activity and subsequently spend those dollars in their communities.

The estimated total impact includes $1.32 to $1.75 billion in Value Added across the 10-year period, which would represent an increase of 0.02% to 0.03% to the state's GDP. We estimate that the Labor Income component of that Value Added ($0.83 to $1.11 billion) would create and sustain 1,552 to 2,115 jobs, at approximately $52,500 to $53,500 per job. These findings are summarized in Table ES-3.

Table ES-3. Summary of HIEE Impact Components, 2021 - 2030 (Low vs. High Scenarios)

Impact	Employment	Labor Income ($Millions)	Value Added ($Millions)
Direct	1,069 - 1,457	$581 - $774	$849 - $1,128
Indirect	217 - 233	$102 - $133	$186 - $240
Induced	311 - 424	$150 - $199	$288 - $382
Total	**1,598 - 2,115**	**$834 - $1,106**	**$1,323 - $1,750**

Unlike the dollar-based impact figures, the job creation figures do not stack cumulatively from year-to-year. Figure 6 shows the number of jobs that the HIEE program would support over the 10-year period, as a function of the amount of revenue generated that year.

Figure ES-4. Annual Employment Supported by HIEE Expenditures, 2021 – 2030

Sources: VCU model of estimated annual RGGI revenue for Virginia (see Section 4)

1. Energy Efficiency as a Solution to Low-Income Energy Burdens

Energy burden and energy insecurity are growing issues for Virginians, particularly among low-income households. The average American household spends $2,177 per year on home energy costs (heating, cooling, lighting, etc.), representing about 3% of their household income.[1] Households that spend more than 6% of their total income on these home energy costs are considered to have "High" energy burden, while those who spend more than 10% are categorized as facing "Severe" energy burden.[2] Households with High or Severe energy burdens often experience "energy insecurity," which refers to an inability to afford basic household heating, cooling, and energy needs, leading to poor health and safety outcomes.

Low-income households are disproportionately more energy burdened, compared to non-low-income households. The concept of a "low-income" household can be defined in different ways, which can sometimes produce seemingly conflicting results when comparing data sources or research studies. Some of the sources cited in this section define "low-income" based on the Federal Poverty Line (FPL), while others are based on percentages of Area Median Income (AMI).[3] Generally speaking, households with incomes of up to 200% of the FPL are considered low-income, as are households with incomes of less than 80% AMI. Households with incomes less than 30% AMI are considered extremely-low-income.[4]

High energy costs are another driver of energy burden and energy insecurity. Virginia's average residential electricity bill of $130.92 per month was 13th highest in the nation as of 2021, but was just 0.33% from the top 10 and 4% away from the top five.[5] The average Dominion Energy customer's bills jumped 30% from 2006-2016,[6] and Appalachian Power bills increased 73% over a similar period.[7]

Energy efficiency is a key strategy to address these challenges, as well-designed energy-efficiency upgrades can substantially reduce household energy costs (i.e., customer bills). Energy efficiency is often cost-effective, according to conventional economic metrics, as an up-front investment in efficiency upgrades can "pay for itself" via reduced energy bills over a reasonable number of years. However, the low-income households that could most benefit from energy-efficiency investments are often unable to do so. First, the majority of low-income households are renters, which means they may not stay in a given housing unit long enough to pay off an energy-efficiency investment, if they are even authorized to make such physical changes to the structure. Low-income homeowners also face barriers, as they often lack the capital or access to financing to make up-front energy efficiency investments.

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[1] U.S. Department of Energy (DOE), Office of Energy Efficiency & Renewable Energy (EERE), 2018. Low-Income Energy Affordability Data (LEAD) Tool. Analysis by authors.

[2] Drehobl, et al., 2020. How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden across the United States.

[3] U.S. DOE, EERE, 2018. *Low-Income Household Energy Burden Varies Among States -- Efficiency Can Help in All of Them*.

[4] U.S. Department of Housing and Urban Development (HUD), 2022. Methodology for Determining Section 8 Income Limits.

[5] U.S. DOE, Energy Information Administration (EIA), 2022. Electric Sales, Revenue, and Average Price. (Table T5a.)

[6] Virginia Poverty Law Center, 2017. *The Myth of Virginia's Rate Utopia: A Comparison of Rates, Riders, and Bills*.

[7] Pate, 2017. *SCC Presentation to the Commission on Electric Utility Regulation*.

A variety of federal, state, and local policies exist to support residential energy efficiency investments, including a number of tax credits and rebates available as a result of the recent federal Inflation Reduction Act. However, these types of incentive-based energy-efficiency programs are generally not accessible for low-income households, as they still require some element of up-front investment. For this study, the more relevant government policies or programs are those that directly support energy-efficiency improvements to low-income households, such as the federal Weatherization Assistance Program (WAP) and the energy efficiency requirements that Virginia and other states place on housing developers who receive the federal Low-Income Housing Tax Credit (LIHTC). Other programs, such as the federal Low-Income Home Energy Assistance Program (LIHEAP) can help reduce low-income energy burdens by providing direct financial assistance to reduce energy bills, but those bill-assistance programs do not provide the same long-lasting benefits that households receive from energy efficiency improvements (some states, including Virginia, use a portion of their LIHEAP funds for weatherization). Finally, electric and natural gas utilities offer a variety of energy efficiency and bill assistance programs for low-income customers, often according to parameters set by state law.

In Virginia, participation in the Regional Greenhouse Gas Initiative (RGGI) has generated over $250 million in low-income energy efficiency funding since 2021, an amount that far exceeds the annual funding provided via the types of programs described above.

1.1. Energy Burden and Energy Insecurity

According to the U.S. Department of Energy (DOE) Office of Energy Efficiency & Renewable Energy's (EERE) Low-Income Energy Affordability Data (LEAD) tool, the average energy burden of low-income households in the U.S. (i.e., those with incomes of 0-80% of AMI) is 7%, compared to 2% for households with incomes above 80% AMI. Broken down into more detail, extremely-low-income households (0-30% AMI) have an average energy burden of 16%, compared to 6% for those in the 30-60% AMI range and 5% in the 60-80% range. In other words, average energy burdens are eight times higher for extremely-low-income households (0-30% AMI), compared to non-low-income households (80% AMI or above).[8]

The average energy burdens across these various income categories are nearly identical for Virginia households, albeit slightly higher (17%) for those in the lowest (0-30% AMI) income bracket. Defining income in a different way, the average energy burden for Virginia households with incomes below the federal poverty level (FPL) is 21%, compared to 18% nationwide. Virginia's average energy burdens are slightly above the national average (8% vs. 7%) for households with incomes between 100-200% of FPL.[9]

However, while low-income energy burdens in Virginia are comparable to the national average, more detailed analysis reveals substantial disparities within the state, with many areas experiencing average energy burdens that far exceed state or national rates. For example, a 2020 study by the American Council for an Energy Efficient Economy (ACEEE) found that 25% of low-income households in the Richmond metro region (defined as less than 200% of the FPL) have an energy burden greater than 15.6%.[10] Energy burden is even more prevalent in some rural parts of the state, as an analysis of LEAD data shows that average energy burdens for low-income households exceed 10% in much of Southwest

[8] U.S. DOE, EERE, 2022. Low-Income Energy Affordability Data Tool. Analysis by authors.

[9] U.S. DOE, EERE, 2022. Low-Income Energy Affordability Data Tool. Analysis by authors.

[10] Drehobl, et al., 2020. How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden across the United States.

and Southside Virginia, reaching as high as 32% in some Census tracts.[11] These local energy burden trends within Virginia are examined in more detail in Section 3 of this report.

These discrepancies are not merely a function of income. According to data from the U.S. Energy Information Administration (EIA), low-income households spend an average of $1.23 per square foot for utilities, while non-low-income households spend $0.98 per square foot.[12] This can be attributed to housing discrimination and market pressures that push low-income people into older, less efficient housing.[13] In particular, older housing, especially in neighborhoods that have experienced historical disinvestment, tend to have poor insulation, an inefficient building envelope, outdated heating and/or cooling systems, and inefficient appliances, all leading to higher energy use.[14]

The disparity in housing conditions leads to higher rates of energy insecurity for low-income households. The characteristics of an energy insecure household can be divided into three categories - physical, economic, and "coping" or behavioral outcomes. Beyond the immediate economic barriers these trends create for vulnerable households, energy insecurity is also an important social determinant of health, as it can eventually lead to significant health issues and dangerous coping strategies.

For example, a low-income household is more likely to live in low-quality housing with older, energy inefficient appliances, which in turn have a higher energy consumption, higher maintenance costs, and increased risk of failure. In response, the household observes certain practices to reduce their use of energy – such as not using air conditioning, or using ovens and space heaters to heat their homes – leading to uncomfortable and potentially unsafe conditions. Besides the acute risks of fire, these strategies have been proven to disrupt sleep, cause stress, anxiety, and depression, increase risks of respiratory illness, and even increase the risk of death due to extreme heat, extreme cold, or carbon monoxide exposure. The elderly and children are most vulnerable to these impacts.[15, 16]

The U.S. Department of Energy's Residential Energy Consumption Survey (RECS) provides data on energy insecurity across different housing types and population demographics. The 2020 RECS data indicates that 27% of U.S. households reported having experienced at least one form of energy insecurity at some point, such as reducing food and/or medical expenditures in order to pay for energy costs, or leaving their homes at an unhealthy temperature. This includes 23% of households living in single-family homes, and 35% of those living in apartments, as well as 40% of renters and 37% of households with children under 18. The prevalence of these forms of energy insecurity varies greatly by income level and racial demographics, as indicated in Figure 1.[17]

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[11] U.S. DOE, EERE, 2022. Low-Income Energy Affordability Data (LEAD) Tool. Analysis by authors.

[12] Virginia Poverty Law Center, 2018. *Electricity Burden and the Myth of Virginia's Rate Utopia*.

[13] Graff, et al., 2021. *Which Households Are Energy Insecure? An Empirical Analysis of Race, Housing Conditions, and Energy Burdens in the United States*. Energy Research & Social Science. 79.

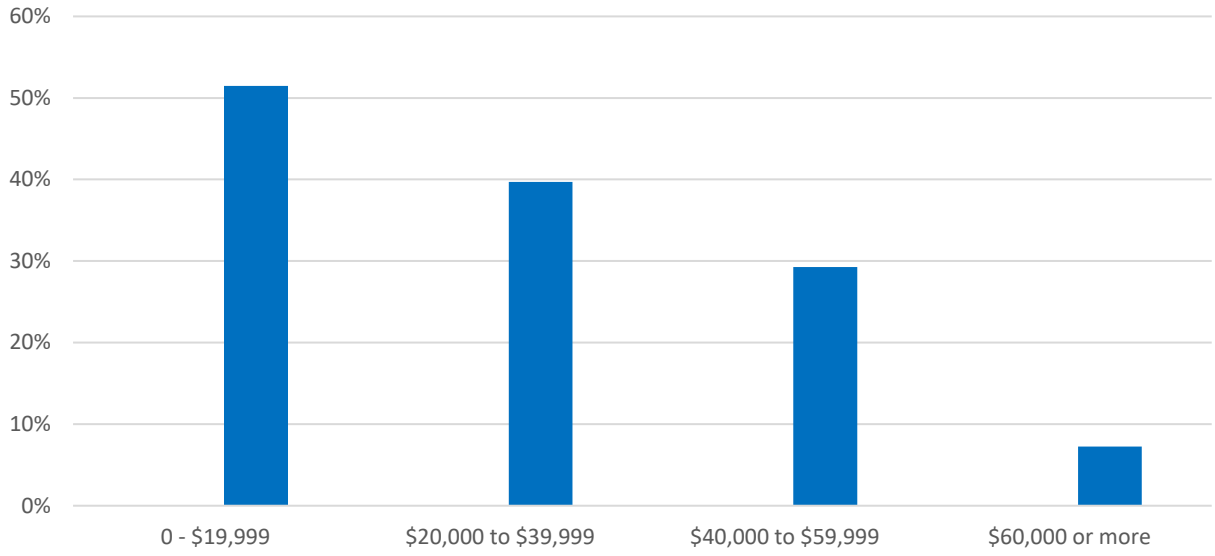
[14] Lewis, et al., 2019. Energy Efficiency as Energy Justice: Addressing Racial Inequities Through Investments in People and Places. Energy Efficiency.

[15] Hernández, et al., 2014. Energy Insecurity among Families with Children.

[16] Graff, et al., 2021. *Which Households Are Energy Insecure? An Empirical Analysis of Race, Housing Conditions, and Energy Burdens in the United States*. Energy Research & Social Science. 79.

[17] U.S. DOE, Energy Information Administration, 2020. Residential Energy Consumption Survey (RECS).

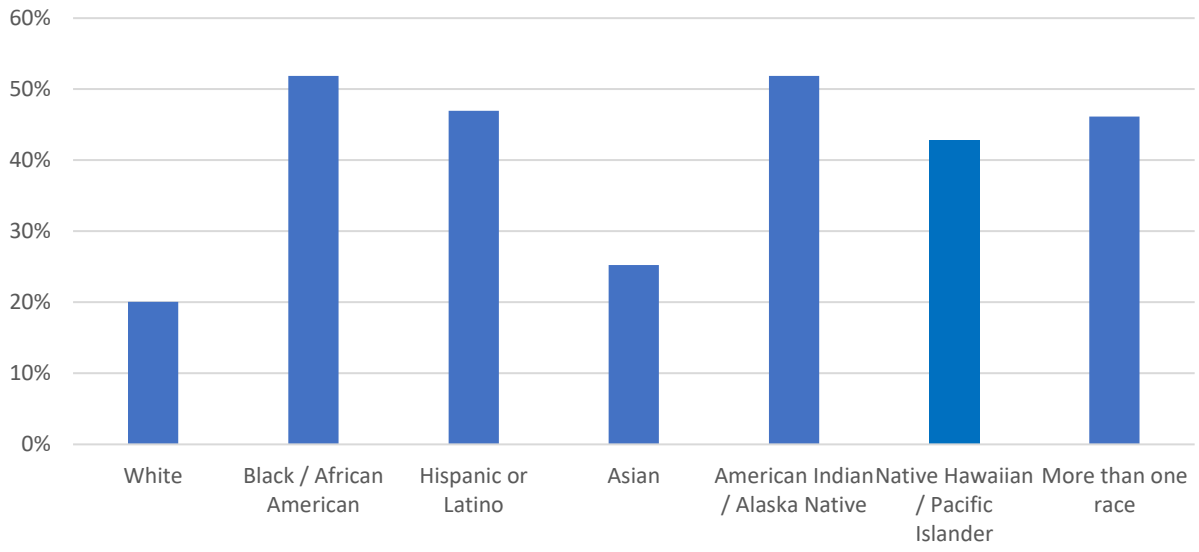
Figure 1. Percentage of Households Experiencing Energy Insecurity, by Household Income



Source: U.S. DOE, 2020. Residential Energy Consumption Survey. Table HC11.1. Additional analysis by authors.

Energy insecurity also varies greatly by race, with about 20-25% of White and Asian households experiencing these impacts, versus 43-52% in all other racial categories, according to the RECS data.

Figure 2. Percentage of Households Experiencing Energy Insecurity, by Racial Category



Source: U.S. DOE, 2020. Residential Energy Consumption Survey. Table HC11.1. Additional analysis by authors.

1.2. Energy Efficiency Opportunities and Policies

An analysis of U.S. Department of Energy data by the American Council for an Energy Efficient Economy (ACEEE) suggests that energy efficiency can reduce residential energy consumption by 25-35% for all income groups. For low-income households, these energy consumption savings could reduce energy burdens by 25%.[18] Potential savings for Virginia households are even higher, as data from the National Renewable Energy Laboratory (NREL) shows that Virginia is one of six states in the highest range of potential low-income household electricity savings, at 29-32%.[19]

Energy efficiency is also a cost-effective option for reducing energy burdens. Cost-effectiveness can be understood as an investment in energy efficiency that produces cost savings – via lower energy bills – that offset the initial investment. Cost effectiveness can be measured in a variety of ways, most commonly through the Simple Payback Period (SPP), or the number of years it takes for energy bill savings to catch up with the initial up-front cost of the energy-efficiency investment. Another method is to calculate the Net Present Value (NPV) of an energy-efficiency investment, or the difference between the initial cost of an upgrade and the energy bill savings over a given period of time. For an energy-efficiency investment to be considered cost-effective, one would look for the SPP to be fewer years than the "life" of the efficiency upgrades, or an NPV greater than zero over that product lifespan.[20]

However, it must be noted that these traditional cost effectiveness metrics do not consider a variety of other important factors. Most notably, basic SPP and NPV calculations typically do not account for future price increases for the energy that is being saved (e.g., electricity is highly likely to cost more per kilowatt-hour in five or ten years than it does today). These metrics also do not recognize important co-benefits that come with an energy-efficiency investment. For example, reducing energy insecurity through energy efficiency can improve residents' health, as detailed in section 1.1. In addition to reducing medical bills, this can lead to fewer medical absences from work and/or school.[21]

Researchers from the National Renewable Energy Laboratory (NREL) have completed numerous studies on residential energy efficiency opportunities in the United States. One study from 2017 estimated that cost-effective energy efficiency retrofits (NPV > 0) to single-family detached homes in the U.S. could produce 4.2 quadrillion British Thermal Units (BTUs) of annual energy savings, equal to 24.4% of all primary energy consumption in those types of homes and 4.2% of all primary energy consumption nationwide.[22] State-level analysis found the potential energy savings in Virginia to be even greater, at approximately 30% of total primary energy consumption in single-family detached homes.[23]

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[18] Drehobl, et al., 2020. *How High Are Household Energy Burdens?: An Assessment of National and Metropolitan Energy Burden across the United States*

[19] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, 2018. *Low-Income Household Energy Burden Varies Among States -- Efficiency Can Help in All of Them*.

[20] Wilson, et. al., 2019. Evaluating energy efficiency potential in low-income households: A flexible and granular approach. Energy Policy vol. 129, p. 710-737.

[21] Wilson, et. al., 2019. Evaluating energy efficiency potential in low-income households: A flexible and granular approach. Energy Policy vol. 129, p. 710-737.

[22] Wilson, et al., 2017. Energy Efficiency Potential in the U.S. Single-Family Housing Stock.

[23] Wilson, et al., 2017. Energy Efficiency Potential in the U.S. Single-Family Housing Stock. See Table A-1, Figure A-2.

The economic benefits and potential savings are especially important for low-income households. In one study, researchers estimated that cost-effective energy efficiency upgrades (defined as an SPP of 13-19 years and NPV > 0) could result in a total potential energy cost savings of $13 billion per year for low-income households across the U.S., or $726 per year per household.[24]

A subsequent NREL study found that economically viable energy-efficiency upgrades to single-family detached homes in Virginia with incomes of less than 200% of the federal poverty level could reduce those customers' bills by $356 million. Among those with incomes of less than 80% of AMI, the total increases to $514 million in potential cost-effective energy efficiency savings.[25] Per the LEAD dataset, there are 375,604 single-family detached homes in Virginia with incomes below 200% of the federal poverty level, and 569,559 below 80% AMI.[26] Cross-referencing these figures generates a potential cost-effective per-household energy savings of $902.45 per year for households below 80% AMI, and $947.48 per year for households below 200% of the federal poverty level.

For multi-family housing, a 2016 study by Optimal Energy found that electricity savings of over 20% could be cost-effectively achieved for affordable multi-family housing units in Virginia, resulting in over $227 million in electricity cost savings, or $354 million after including natural gas and other fuels.[27]

However, while low-income energy efficiency has great technical potential, there are many barriers to low-income residents actually realizing those opportunities, most significantly the upfront cost of investing in energy-efficiency upgrades. One barrier is that many existing energy-efficiency programs are not specifically designed for low-income households. These "market-rate" programs, i.e. programs that provide a tax credit, rebate, or other economic incentive to offset the up-front cost of an energy efficiency upgrade, are generally inaccessible to non-low-income households, due to an inability to meet even those reduced upfront costs, and/or a lack of qualifying credit.[28]

These challenges are compounded for renter-occupied households, which represent an estimated 59% of all low-income households across the country. Owners and landlords do not have a financial incentive to pay for energy-efficiency improvements, which leaves the energy burden on the tenants.[29] This is known as the "split-incentive" problem, in that the residents of multifamily buildings or other rental housing units can benefit from energy-efficiency improvements to reduce their energy bills, but the owners of those units would not realize any economic benefit and therefore have no direct financial incentive to pay for those efficiency improvements.[30]

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[24] Wilson, et. al., 2019. Evaluating energy efficiency potential in low-income households: A flexible and granular approach. Energy Policy vol. 129, p. 710-737.

[25] Wilson, et. al., 2019. Evaluating energy efficiency potential in low-income households: A flexible and granular approach. Energy Policy vol. 129, p. 710-737.

[26] U.S. DOE, EERE, 2022. Low-Income Energy Affordability Data Tool. Analysis by authors.

[27] Optimal Energy, 2015. Potential for Energy Savings in Affordable Multifamily Housing.

[28] American Council for an Energy-Efficient Economy, 2022. Low-Income Energy Efficiency Programs.

[29] U.S. DOE, State and Local Solution Center, 2021. Low-Income Community Energy Solutions.

[30] Samarripas, York, 2019. Closing the Gap in Energy Efficiency Programs for Affordable Multifamily Housing.

1.2.1 Federal Programs to Address Energy Burden and Increase Energy Efficiency

This section discusses the primary federal programs that support residential energy efficiency or can help to reduce energy burdens for low-income households. While a variety of tax credits and other programs exist to support market-rate energy-efficiency investments for the broader population, those are generally not accessible to low-income households for the reasons stated earlier in section 1.2.

One of the most significant sources of support for low-income residential energy efficiency is the U.S. Department of Energy's Weatherization Assistance Program (WAP). The WAP program was created in 1976 to provide upgrades to "weatherize" homes for households with incomes less than 200% of the federal poverty level.[31] These improvements, such as insulation and air sealing as well as updated appliances, also contribute to improving health and safety standards by reducing energy related hazards. The WAP program supports 8,500 jobs and provides weatherization services to approximately 35,000 homes across the U.S. yearly, with an average annual savings of $372 per household.[32]

The Low-Income Home Energy Assistance Program (LIHEAP) was formed in 1981 and provides federal assistance – passed through state, territorial, and tribal agencies – to reduce energy costs for low-income households.[33] This program primarily provides monetary relief to low-income households, in the form of heating, cooling, and emergency bill assistance, but states also have the flexibility to allocate up to 15% of their LIHEAP funds to energy conservation measures (often via the same agency that manages the WAP program).[34] From 2018-2022 Virginia received roughly $85-$95 million per year in LIHEAP funds, but this number is increasing to over $115 million in FY 2023 due to additional funding from the Infrastructure Investment and Jobs Act.[35] In FY 2022 Virginia spent 42% of its LIHEAP funds on heating assistance, 20% on cooling and crisis assistance, and 15% on weatherization. (Federal law allows states to spend up to 10% of LIHEAP funds on administration, and carry up to 10% to the next fiscal year).[36]

The Low-Income Housing Tax Credit (LIHTC) program was created by the Tax Reform Act of 1986, and allows state and local agencies to issue approximately $8 billion in tax credits for the acquisition, rehabilitation, or new construction of rental housing targeted to lower-income households.[37] State agencies receive a set amount of tax credits, based on population, which are then distributed according to the state's qualified allocation plan. These plans typically include criteria for energy efficiency and green building, to support sustainability and resilience for low-income families.[38] The Virginia Housing Development Authority (aka Virginia Housing) requires projects that receive LIHTC credits to achieve certain energy efficiency benchmarks,[39] as discussed in Section 1.4.1 of this report.

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[31] U.S. DOE, EERE, 2022. Weatherization Assistance Program.

[32] U.S. DOE, EERE, 2022. Weatherization Assistance Program Factsheet.

[33] U.S. Department of Health and Human Services (DHHS), Office of Community Services, 2022. Low Income Home Energy Assistance Program.

[34] U.S. DHHS, LIHEAP Clearinghouse, 2022. LIHEAP Program Components.

[35] U.S. DHHS, Office of Community Services, 2022. LIHEAP Fact Sheet FY2022.

[36] U.S. DHHS, LIHEAP Clearinghouse, 2022. LIHEAP Funds by Program Component.

[37] U.S. HUD, Office of Policy Development and Research, 2022. Low-Income Housing Tax Credit (LIHTC).

[38] Wasser, 2021. *Deep Dive: How State LIHTC Programs Reference Third-Party Green Building Programs*.

[39] Virginia Center for Housing Research, 2017. Sustaining Energy Efficiency: Longitudinal Evidence of Virginia's Low-Income Housing Tax Credit Properties.

In 2021 the U.S. Congress passed the Infrastructure Investment and Jobs Act, also known as the "Bipartisan Infrastructure Law" (BIL). The BIL is intended to support various aspects of American infrastructure, such as rebuilding roads, bridges, and rails, expanding access to clean drinking water, ensuring high-speed internet access, tackling the climate crisis, advancing environmental justice, and investing in communities.[40] The BIL also supports low-income residential energy efficiency by including $3.5 billion in additional WAP funds.[41] This will provide a one-time investment of $65.59 million for Virginia, on top of the state's regularly allocated WAP funding.[42] The BIL makes another $550 million available for energy efficiency and clean energy projects through the Energy Efficiency and Conservation Block Grant Program.[43] In recent years Virginia has used these block grant funds for projects such as audits and improvements to public buildings, energy efficiency training for localities,[44] and building energy code trainings,[45] none of which is specifically targeted to low-income households.

In 2022, Congress passed the Inflation Reduction Act (IRA),[46] which included billions of dollars in grant and loan programs, as well as a variety of new and modified tax incentives, to support investments in clean energy technology and address the climate change crisis. The IRA extends tax credits for residential energy efficiency projects with a total of $8.6 billion split between the Home Energy Performance-Based Whole-House Rebate program and the High-Efficiency Electricity Home Rebate Program.[47] However, these programs are generally not applicable to low-income households, as they still require some up-front investment in order to receive the applicable tax credits and rebates. Furthermore, low-income homeowners that do not have an income tax liability cannot access these credits.[48] There is a provision that allows local governments and non-profits to receive these tax credits in rebate form, but this option cannot be used by individual households.[49]

1.2.2 Virginia Energy Efficiency Programs

A variety of state, local and utility-sponsored energy-efficiency programs are available in Virginia, offering customers tax credits, subsidies, and rebates for installing and using energy-efficient appliances and products. These programs are available to the general public, and help to reduce energy use and carbon emissions, but without addressing energy burdens for low-income households. For example, the Virginia Department of Taxation created a financial incentive program for residential properties called

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[40] The White House, Briefing Room Statement, 2021. Fact Sheet: The Bipartisan Infrastructure Deal.

[41] Bertrand, Environmental and Energy Study Institute, 2022. How the Inflation Reduction Act and the Bipartisan Infrastructure Law Work Together to Advance Climate Action.

[42] Warner, M. 2022. Warner & Kaine Announce More than $65 Million in Federal Funding to Make Virginia Homes More Energy Efficient and Lower Utility Costs.

[43] Bertrand, Environmental and Energy Study Institute, 2022. How the Inflation Reduction Act and the Bipartisan Infrastructure Law Work Together to Advance Climate Action.

[44] Central Shenandoah Planning District Commission. Energy.

[45] Southeast Energy Efficiency Alliance. Regional Investments: Southeast Energy Efficiency Fund.

[46] Committee for a Responsible Federal Budget, 2022. *What is the Inflation Reduction Act*.

[47] The White House, 2022. Clean Energy Innovation and Implementation. Building A Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investment in Clean Energy and Climate Action.

[48] Utility Dive, 2022. *The Inflation Reduction Act leaves low-income homeowners out of the clean energy transition. Or does it?*

[49] Clean Energy Group, 2022. *CEG Comments on Direct Pay Option within the Inflation Reduction Act*.

the Income Tax Reduction for Energy-Efficient Products program.[50] Taxpayers may deduct from their taxable personal income an amount equal to 20% of the sales taxes paid for certain equipment, capped at $500. Another state financial incentive is the Property Tax Assessment for Energy Efficient Buildings. This program allows local jurisdictions to assess the property taxes of energy efficient buildings at a reduced rate, by considering them as a separate class of property for local taxation purposes. Localities that have enacted this ordinance include Charlottesville and Virginia Beach.[51]

Another existing program is the State Energy Program (SEP). The SEP is a federal program that provides funding and technical assistance for states to administer energy efficiency and renewable energy programs.[52] From 2015 to the present, Virginia has received $9.4 million from SEP, for an average of $1.34 million/ year. Virginia uses these funds for a few programs, only one of which, the Commercial-Property Assessed Clean Energy (C-PACE) programs, can be accessed by residential property owners.[53] Virginia's C-PACE program can be used by owners of commercial and 5+-unit multi-family buildings to cover the up-front cost of energy efficiency and clean energy projects. The cost is then paid back through annual property tax increases. These programs are not currently available for homeowners, and there are no income eligibility requirements.[54] While C-PACE programs have been enabled in 18 Virginia localities,[55] it has not been widely used, and has mostly remained within the commercial sector.[56]

Before the Virginia Clean Economy Act (VCEA) was passed in 2020, utility companies had some limited energy efficiency programs for low-income customers. For example, Dominion Energy has run its EnergyShare program for 40 years, which currently provides about $6.5 million per year in bill assistance and $6 million in weatherization for vulnerable customers.[57] Appalachian Power Company (APCO) launched a low-income weatherization program in 2014 that supplemented existing state and federal weatherization programs,[58] for which they were able to recover the costs through their base rate.[59]

Some of Virginia's natural gas utilities also offer small low-income energy efficiency programs. For example, Washington Gas and Columbia Gas of Virginia both operate programs in partnership with Community Housing Partners, which together offer about $1.5 million in upgrades per year.[60]

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[50] Database of State Incentives for Renewables and Efficiency, 2020. Income Tax Deduction for Energy-Efficiency Products, North Carolina Clean Energy Technology Center and North Carolina State University

[51] Database of State Incentives for Renewables and Efficiency, 2020. Local Option – Property Tax Assessment for Energy Efficient Buildings, North Carolina Clean Energy Technology Center and North Carolina State University.

[52] U.S. DOE, EERE, 2020. State Energy Program National Evaluation

[53] U.S. DOE, EERE, 2022. Weatherization and Intergovernmental Programs Office Project Map-Virginia

[54] Virginia Energy. PACE

[55] Virginia Energy Efficiency Council, 2022. C-PACE.

[56] Energy News Network, 2021. Virginia finally has its first C-PACE success story, a decade after initial law.

[57] Dominion Energy, 2021-22. EnergyShare Annual Report.

[58] Appalachian Power, 2015. Appalachian Power Launches Two Programs to Help Virginia residential customers use energy more efficiently.

[59] Virginia State Corporation Commission, 2018. Petition of Appalachian Power Company for approval to extend two existing demand-side management programs; Final Order.

[60] Community Housing Partners, 2023. Personal communication from Chase Counts, Senior Director of Operations, Energy Solutions. (January 12, 2023).

In 2018, the passage of the Grid Transformation and Security Act (GTSA) required the state's two primary investor-owned electric utilities propose just over $1 billion in customer energy efficiency programs over the next decade – $870 million for Dominion and $140 million for APCO – including any previously approved energy efficiency programs existing at the time. It did not include specific energy savings goals or require the State Corporation Commission (SCC) to approve the proposed programs.[61]

In 2020, the Virginia Clean Economy Act (VCEA) was signed into law. This legislation is designed to create a 100% carbon-free electricity grid and end in-state fossil fuel generation in Virginia by the year 2050, in addition to creating thousands of new instate jobs in renewable energy and keeping bills low with ratepayer protections and energy efficiency investments.[62] The VCEA includes a specific program that caps monthly bills for low-income Virginians to help alleviate the energy burden of rising costs.[63]

The passage of the VCEA also set mandatory Energy Efficiency Resource Standards for investor-owned electric utilities, which must be met through energy efficiency programs for customers. These standards set a mandatory target of 5% energy reduction for Dominion by 2025, while APCO's reduction target is 2%. After 2025, the SCC is directed to set these targets every three years. They are enforceable because approval of new fossil fuel plants is contingent on evidence of reaching these targets. Dominion and APCO are able to recover the cost of energy efficiency programs though their customers.

The VCEA also increased the percentage of the utilities required energy efficiency spending that must go to LMI households from 5 to 15%.[64] As noted above, the GTSA required the state's investor-owned utilities to spend a combined $1.01 Billion over 10 years, thus about $15 million per year must go to LMI programs. According to the SCC's annual report on energy efficiency programs pursuant to the VCEA, Dominion's Income and Age Qualifying Home Improvement program will spend around $27 million over seven years. They report that this will result in 9,588 Megawatt-hours (MWh) of annual electricity savings. This same report indicates that APCo's low-income single and multi-family programs will result in a net electricity savings of 1,460 MWh per year.[65]

In 2020, the Virginia General Assembly passed the Clean Energy and Community Flood Preparedness Act (HB 981 / SB 1027), which directed the Department of Environmental Quality to develop regulations for entering Virginia into the Regional Greenhouse Gas Initiative (RGGI). The legislation requires that 50% of Virginia's revenue from RGGI "shall be credited to an account administered by [the Department of Housing and Community Development (DHCD)] to support low-income energy efficiency programs," while 45% shall be used for "assisting localities and their residents affected by recurrent flooding, sea level rise, and flooding from severe weather events," with the last 5% going to administrative costs.[66]

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[61] Virginia Legislative Information System, 2018. VIRGINIA ACTS OF ASSEMBLY -- 2018 SESSION.

[62] Chesapeake Climate Action Network, 2020. The Virginia Clean Economy Act (HB1526 and SB851): Putting Virginia on the Path to 100% Clean Electricity.

[63] Chesapeake Climate Action Network, 2020. The Virginia Clean Economy Act SB 851.

[64] American Council for an Energy-Efficient Economy, 2022. State and Local Policy Database: Virginia.

[65] Virginia State Corporation Commission, 2022. Combined Report on Energy Efficiency Programs and Feasibility of Achieving Energy Efficiency Goals.

[66] Virginia Legislative Information System, 2020. HB 981 Clean Energy and Community Flood Preparedness Act.

2. The Regional Greenhouse Gas Initiative (RGGI) and Energy Efficiency for Virginia

The Regional Greenhouse Gas Initiative (RGGI) is an agreement between eleven eastern U.S. states to lower greenhouse gas emissions from power plants by establishing a regional cap on carbon dioxide (CO_2) emissions. To enforce the cap, power plants in participating states must purchase allowances to cover their carbon emissions. Each allowance permits the emission of 1 short ton of CO_2. Participating states receive a set number of allowances based on their share of regional emissions, with the total cap going down each year. Participating states sell CO_2 allowances quarterly at auctions, organized and regulated by RGGI member states and an independent market monitor. To ensure stability in the market for allowances, there is a minimum reserve price, as well as minimum and maximum prices that will trigger either the removal of allowances or the release of reserve allowances.[67]

So far, Virginia has brought in $524 million in revenue from eight quarterly RGGI auctions, which would have translated into $262 million in low-income energy-efficiency funding via the DHCD's Housing Innovations in Energy Efficiency program (HIEE).[68] However, in 2022 the General Assembly diverted $11.4 million from HIEE to support the town of Hurley, VA, which had experienced a major flooding event in 2021.[69] This results in a final total of $252 million allocated to the HIEE program thus far, as shown in Table 1 and Figure 3 below.

Table 1. RGGI Revenue and HIEE Allocations for FYs '21-23

Fiscal Year	Auctions	RGGI Revenue ($Millions)	HIEE Allocation ($Millions) [a]
2021	51	$43.59	$21.79
2022[b]	52, 53, 54, 55	$258.27	$117.73[c]
2023	56, 57, 58	$224.6	$112.3
Totals		$526.5	$251.8

Source: RGGI, 2022. Cumulative Allowances and Proceeds-Virginia. Additional calculations by authors.

a. HIEE *revenue is equal to half of the total RGGI auction results for Virginia for each fiscal year*

b. While Auction 52 took place in June 2021 (i.e., FY '21) and Auction 56 occurred June 2022 (FY '22), the resulting funds were allocated to the DHCD FY '22 and FY '23 budgets, respectively.[70, 71]

c. The total shown here for the FY 2022 HIEE allocation includes 50% of that year's RGGI revenue ($129.1 million), minus the $11.4 million diverted to the Hurley Flood Relief fund.

[67] The Regional Greenhouse Gas Initiative, 2021. RGGI 101 Fact Sheet.

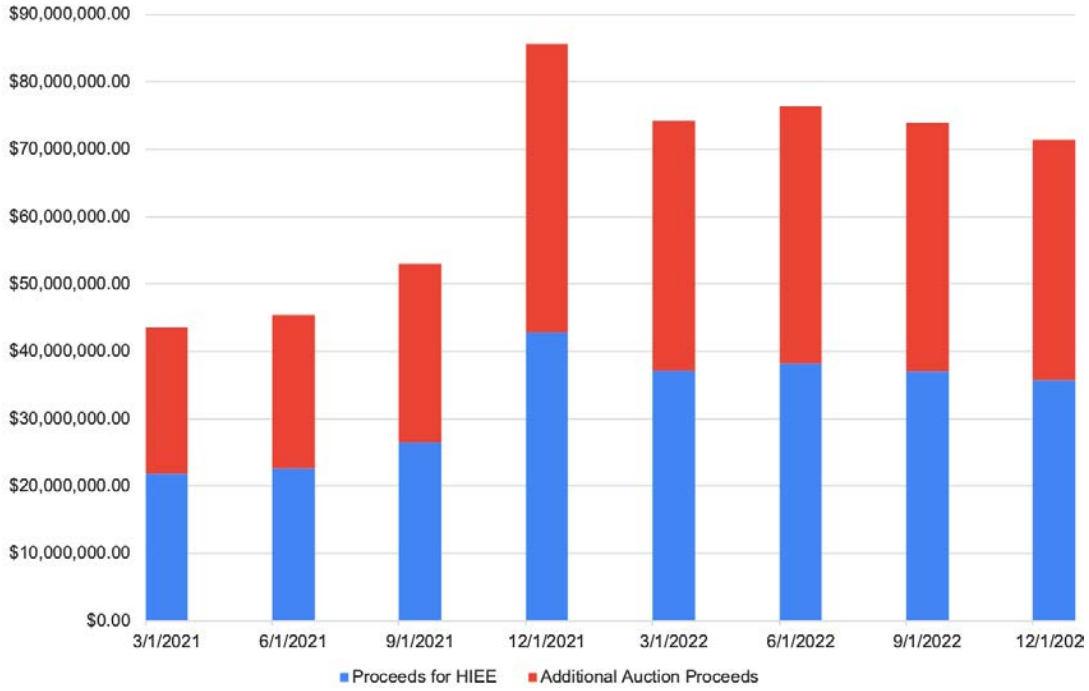
[68] The Regional Greenhouse Gas Initiative, 2022. *Cumulative Allowances and Proceeds-Virginia*.

[69] Moomaw, G. and Vogelsong, S., 2022. *After months of wrangling, Virginia has a budget deal. What's in it?*

[70] Virginia Department of Housing and Community Development (DHCD), 2021. Housing Innovations in Energy Efficiency (HIEE) Program: Fifth Stakeholder Advisory Group and Public Meeting (presentation slides).

[71] Virginia DHCD, 2021. *Housing Innovations in Energy Efficiency (HIEE) Program: Ninth Stakeholder Advisory Group and Public Meeting* (presentation slides).

Figure 3. Quarterly RGGI Auction Revenue for Virginia, March 2021 – December 2022



Source: RGGI, 2022. Cumulative Allowances and Proceeds-Virginia. Additional calculations by authors.

2.1. The Housing Innovations in Energy Efficiency (HIEE) Program

Upon passage of the Clean Energy and Community Flood Preparedness Act, the DHCD formed the HIEE program as the entity to manage and distribute the low-income energy efficiency funds generated by Virginia's participation in the RGGI program. The DHCD formed a 15-member Stakeholder Advisory Group, comprised of "advocacy groups, affordable housing developers, housing development authorities, weatherization agencies and building energy consultants" to provide expertise on the affordable housing market, "achieve broad agreement on key program components," and help the agency "connect with community and thought leaders on strategic investments of Regional Greenhouse Gas Initiative (RGGI) funds.[72]

A presentation from the first stakeholder meeting listed the following objectives for the RGGI funds:

- Deep energy retrofits (exceeding energy code requirements) that complement existing affordable housing construction and rehabilitation incentives, to ensure lowest income population benefits from long-term cost savings;
- Incorporate innovative approaches that will overcome traditional barriers to building and retrofitting affordable housing at scale;

[72] Virginia DHCD, 2020. Housing Innovations in Energy Efficiency (HIEE) Program: First Stakeholder Advisory Group and Public Meeting (presentation slides).

- Prioritize long-term sustainability / durability and occupant health (e.g. preventing moisture issues, improving ventilation) along with energy efficiency upgrades[73]

The HIEE Stakeholder Advisory Group met at least nine times between Dec. 2020 and Dec. 2021. By the fourth meeting, in Feb. 2021, the DHCD had decided to divide the HIEE funds across the Affordable and Special Needs Housing (ASNH), Weatherization Deferral Repair (WDR), and Housing Innovations Partnership (HIP) grants programs, according to the percentages indicated in Table 2.

Table 2. RGGI Revenue and HIEE Allocations for FYs '21-23

Fiscal Year	ASNH	WDR	HIP
FY '21	40%	60%	0%
FY '22	60%	30%	10%

Source: Virginia Department of Housing and Community Development, 2021. Housing Innovations in Energy Efficiency (HIEE) Program: Fourth Stakeholder Advisory Group and Public Meeting (presentation slides).

The RGGI auctions have generated over $250 million in funding for HIEE, as shown in Table 1, approximately $117 million of which has been spent or committed to energy efficiency projects thus far:

- In July, 2021, the DHCD announced the release of over $21 million in ASNH funds (from various sources) to support 24 low-income multi-family housing projects across Virginia. This included $6.2 million in HIEE funds, which was divided among 11 projects with a total of 707 units.[74]
- In January, 2022, the DHCD announced the release of an additional $60 million in ASNH funds. This included $22.96 million from HIEE, divided among 25 projects with a total of 1,682 units.[75]
- In an October 2022 webinar, DHCD staff stated that approximately $80 million in HIEE funding would be available for Affordable and Special Needs Housing projects (ASNH) during FY '23.[76]
- According to a December, 2022 update from DHCD, the WDR program has committed $7.92 million thus-far, including funds spent and the estimated costs of pre-approved projects. The current total of 558 projects (306 completed, and 252 pre-approved) includes 544 single family projects and 507 multi-family units across 14 projects, for a total of 1,051 units.[77]
- No HIEE funds appear have been spent to-date via the HIP program.

[73] Virginia DHCD, 2020. Housing Innovations in Energy Efficiency (HIEE) Program: First Stakeholder Advisory Group and Public Meeting (presentation slides).

[74] Virginia DHCD, 2022. *Governor Northam Announces Over $21 Million in Affordable and Special Needs Housing Loans*.

[75] Virginia DHCD, 2022. *Governor Northam Announces Over $60 Million in Affordable and Special Needs Housing Loans*.

[76] Virginia DHCD, 2022. *Affordable and Special Needs Housing-ASHN-How to Apply*. Minute 20:00. [Webinar].

[77] Virginia DHCD, 2022. Personal communication from Aaron Shoemaker, Program Administrator, Energy Efficiency Office. (December 8, 2022).

2.2. The Affordable and Special Needs Housing (ASNH) Program

The ASNH program combines funds from a variety of sources, including HIEE, to "expand the supply of decent, safe, sanitary, and affordable housing available to low-income, very low-income, and extremely-low income Virginians." Eligible projects fall into one of three categories – new construction, substantial rehabilitation, or adaptive reuse – and must include a minimum of five units of housing. The HIEE funding dedicated to the ASNH program is intended to "assist affordable housing project development teams in completing energy efficiency upgrades that would not have been feasible otherwise," and which meet certain energy performance requirements indicated in Table 3 below. Additional HIEE energy efficiency requirements include green building certification, fresh air ventilation, dehumidification, and duct leakage testing and sealing, among others stipulations.[78]

Table 3. Energy Efficiency Requirements for HIEE Funds Included in ASNH Program

Project Type	VA Housing LIHTC Requirement	HIEE Requirement
New Construction	ENERGY STAR v3.0	Zero Energy Ready Homes (ZERH)
Substantial Rehab	30% improvement in HERS index [a] or HERS index 80 (or below)	40% improvement in HERS index or avg. of HERS 70 (or below) across all units
Adaptive Reuse	HERS index 95 (or below)	Average HERS index of 80 or below across all units

Source: Virginia Department of Housing and Community Development, 2021. Housing Innovations in Energy Efficiency (HIEE) Program: Seventh Stakeholder Advisory Group and Public Meeting (presentation slides.

a. The Home Energy Rating System (HERS) Index is a standard metric for home energy efficiency. A score of 100 represents baseline standard energy efficiency for a given unit type, and lower scores represent increasing efficiency. A HERS index 80 indicates that a housing unit is 20% more efficient than the baseline reference unit.[79]

Individual ANSH projects that meet the HIEE performance requirements are eligible for HIEE awards of up to $2 million, or 10% of the total project construction costs, whichever is less.[80] To avoid confusion, the HIEE funds dedicated to the ASNH program are hereafter referred to as "ASNH-Energy Efficiency" funds (ASNH-EE) in this report. As indicated above, the DHCD has announced over $29 million in ASNH-EE funds, supporting 2,389 total units,[81, 82] with an additional $80 million available for FY '23.[83]

[78] Virginia DHCD, 2022. Affordable and Special Needs Housing Competitive Application Program Guidelines FY 2023 (presentation slides).

[79] RESNET, 2022. What is the HERS Index?

[80] Virginia DHCD, 2022. Affordable and Special Needs Housing Competitive Application Program Guidelines FY 2023 (presentation slides).

[81] Virginia DHCD, 2022. *Governor Northam Announces Over $21 Million in Affordable and Special Needs Housing Loans.*

[82] Virginia DHCD, 2022. *Governor Northam Announces Over $60 Million in Affordable and Special Needs Housing Loans.*

[83] Virginia DHCD, 2022. Affordable and Special Needs Housing Competitive Application Program Guidelines FY 2023 (presentation slides).

2.3. The Weatherization Assistance (WAP) and Weatherization Deferral Repair (WDR) Programs

The WDR program is funded exclusively by HIEE, and supports repairs to housing units (single-family homes or multi-family buildings) that are in such poor condition as to have been deemed unsuitable for weatherization, and have thus been "deferred" from the U.S. federal government's Weatherization Assistance Program (WAP).[84] In Virginia, DHCD administers this program in partnership with WAP providers throughout the state. Virginia receives funds from WAP each year to realize specific weatherization projects through the state's weatherization providers.

Nationally, about 1 in 5 households that apply for the WAP program have to be rejected because the homes are in such poor condition that they are not deemed eligible for weatherization. In Virginia, weatherization providers had to defer services to 525 out of 2,901 applicants (25%) in 2018. As the weatherization program grows, the anticipated number of deferrals in Virginia increases to 1,500 per year.[85] The WDR program bridges this gap by investing in repairs needed to bring otherwise ineligible households out of deferral.[86]

A review of the annual "State Plans" that DHCD submits to the U.S. Department of Energy indicates that Virginia received approximately $22.62 million in WAP funding from 20018-2022, of which $15.61 million was spent on program operations (i.e., spent directly on weatherization projects). This resulted in the weatherization of over 2,300 homes (average of around $6,700 per unit), as shown in Table 4 (note that these plans do not distinguish between single-family and multi-family units).[87]

A report from the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy provides slightly different numbers for weatherization in Virginia. According to that data, the state received $36.4 million in WAP funding from 2015-2022, and has weatherized 6,628 homes in that time period (an average of 828.5 homes per year at less than $5,500 per unit). The same source also indicates that Virginia weatherized an average of 707 homes per year from 2010-2021.[88]

[84] Virginia DHCD, 2022. Affordable and Special Needs Housing Competitive Application Program Guidelines FY 2023 (presentation slides).

[85] Counts, C., 2020. Utilizing Virginia RGGI Revenue to Support Existing Low-Income Energy Efficiency Programs.

[86] Virginia DHCD, 2021. *Virginia Weatherization Deferral Repair Program Guidelines: 2021-2022.*

[87] Virginia DHCD, 2022. Weatherization Assistance Program (WAP). Data pulled from links for DOE State Plans, 2018-2022.

[88] U.S. DOE, EERE, 2022. Weatherization and Intergovernmental Programs Office Project Map – Virginia.

Table 4. Annual WAP Allocations for Virginia Weatherization Projects

Calendar Year	Total WAP Funding ($Millions)	Program Operations ($Millions)	Total Dwelling Units Weatherized	Average Cost per Dwelling Unit [a]
2018	$3.14 [b]	$2.34	325	$7,212
2019	$4.74	$2.84	377	$7,526
2020	$6.28	$3.69	490	$7,531
2021	$6.44	$3.85	649	$5,938
2022[c]	$5.16	$2.89	488	$5,932
Totals	$22.62	$15.61	2,329	$6,702

Source: Virginia Department of Housing and Community Development, 2022. Weatherization Assistance Program (WAP). *Data pulled from links for DOE State Plans, 2018-2022.*

[a] *Totals in this column do not exactly match results from dividing Program Operations / Total Dwelling Units Weatherized columns, due to rounding of Program Operations totals.*

[b] *The 2018 plan only included funding totals for subgrantee awards. All other years also included overhead totals.*

[c] *The 2022 DOE State Plan is still listed as a "draft" on DHCD's website as of 12/12/22.*

The passage of the federal Infrastructure Investment and Jobs Act (H.R.3684) in November 2021, commonly known as the Bipartisan Infrastructure Law (BIL), includes $3.5 billion for the WAP program. This will provide $65.59 million for Virginia WAP,[89] which is in addition to the regular WAP annual grants and is available until expended.[90] The DHCD's draft application for these funds indicates that $38.5 million of those funds would go to program operations, resulting in the weatherization of 4,808 units of housing at an average of around $8,000 per unit weatherized.[91]

Assuming that Virginia's regular annual WAP awards continue to fund about 465 units per year (the average from 2018-2022 per Table 4), that would add up to about 3,720 units weatherized from 2023 through 2030. If the additional BIL funds were distributed over that same period of time, those projected additional 4,808 units would bring the total to over 8,500 units, or about 1,065 per year.

[89] Warner, M. 2022. Warner & Kaine Announce More than $65 Million in Federal Funding to Make Virginia Homes More Energy Efficient and Lower Utility Costs.

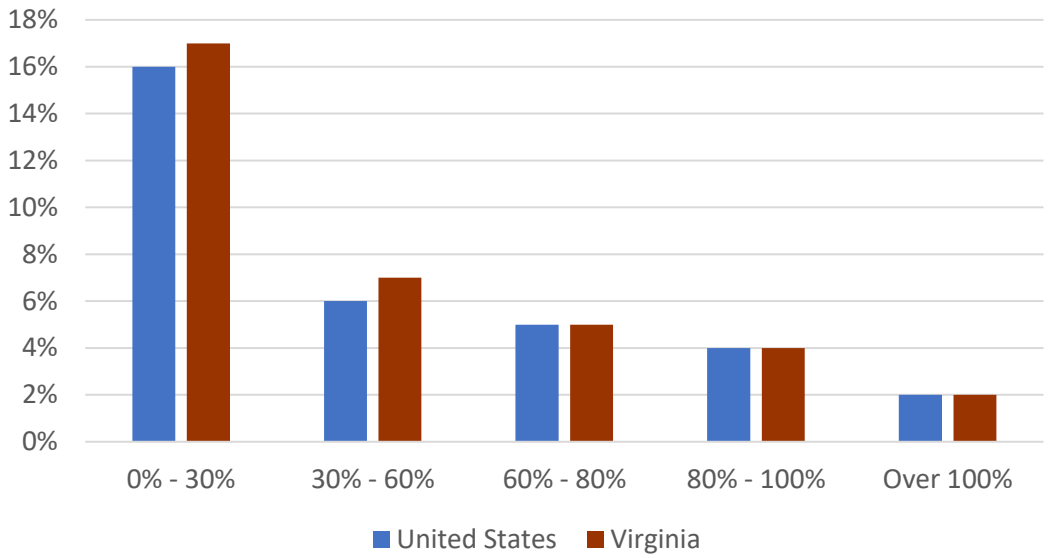
[90] U.S. DOE, 2022. Weatherization Program Notice BIL 22-1.

[91] Virginia DHCD, 2022. Weatherization Assistance Program (WAP). DRAFT BIL WAP 2022-2027 State Plan.

3. Analysis of Energy Burden in Virginia

As discussed earlier in this report, the U.S. Department of Energy's (DOE) Low-Income Energy Affordability Data (LEAD) Tool demonstrates how low-income households spend significantly greater percentages of their income on household energy costs (heating, cooling, etc.). This is particularly true of extremely-low-income households, i.e., those household incomes between 0-30% of the Area Median Income (AMI), whose average energy burden of 16% is eight times higher than that of households with an income above 80% AMI. Average energy burdens for Virginia households generally match those national averages across AMI income groups, as shown in Figure 4 below.[92]

Figure 4. Average Energy Burden by Household Income, Virginia vs. United States



Source: U.S. DOE, EERE, 2022. Low-Income Energy Affordability Data Tool. Analysis by authors.

Using the Federal Poverty Level (FPL) as the income metric, rather than AMI, produces somewhat different results. The FPL is a standardized metric that applies equally across the contiguous United States, based on family size (e.g., $27,750 for a family of four).[93] The AMI is calculated at the regional level, and can vary widely. In Virginia, the 30% AMI threshold for a family of 4 is $42,700 in the Washington-Arlington-Alexandria region, but is less than half of that amount in many other regions of the state (e.g., $21,350 in King and Queen County).[94]

The average energy burden for Virginia households with incomes below the FPL is 21%, compared to 18% nationwide. Virginia's average energy burdens are also slightly above the national average (8% vs. 7%) for households with incomes between 100-200% of FPL.[95]

[92] U.S. DOE, EERE, 2022. Low-Income Energy Affordability Data Tool. Analysis by authors.

[93] U.S. DHHS, 2022. Poverty Guidelines.

[94] U.S. HUD, 2022. 2022 Adjusted Home Income Limits: Virginia.

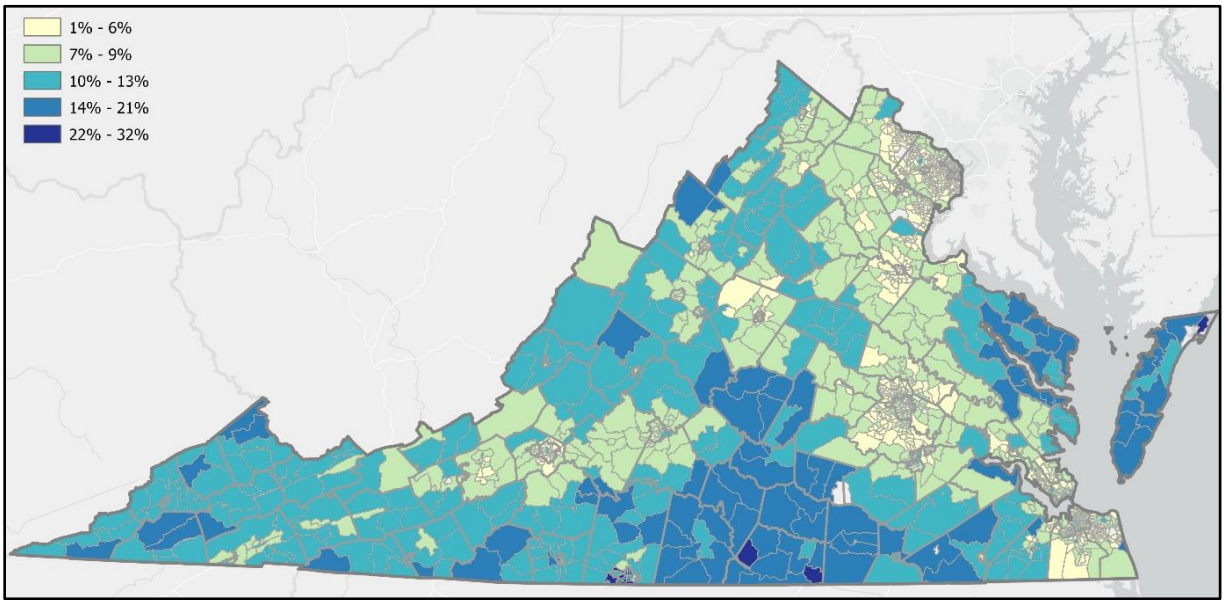
[95] U.S. DOE, EERE, 2022. Low-Income Energy Affordability Data Tool. Analysis by authors.

3.1. Regional Comparison of Average Low-Income Energy Burdens Across Virginia

Comparing Virginia's energy burdens to the national average obscures the substantial disparities that exist within the state. To evaluate these regional disparities, we conducted additional analysis using raw data from the LEAD tool, which incorporates the US Census Bureau's 2018 American Community Survey (ACS) Public Use Microdata Samples (PUMS),[96] and the US Census TIGER/Line Geodatabases.[97] More details on these data sources and our methodology can be found in Appendix A.

Through this process we calculated the average energy burden for low-income households (incomes below 80% AMI), for every Census tract in Virginia, as shown in Map 1 below. Hereafter we refer to the average energy burden for low-income households in a given Census tract using the acronym AEB-LI.

Map 1. Average Energy Burden of Low-Income Households by Census Tract (2018)



Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

Map 1 demonstrates that low-income households face High (above 6%) to Severe (above 10%) average energy burdens throughout much of the state. Every Census Tract shaded in any color but light yellow has an AEB-LI of at least 7%. Much of the state's rural areas have an AEB-LI of 10% and above, including nearly all of Southwest Virginia, Southside Virginia, the Northern Neck, and the Eastern Shore.

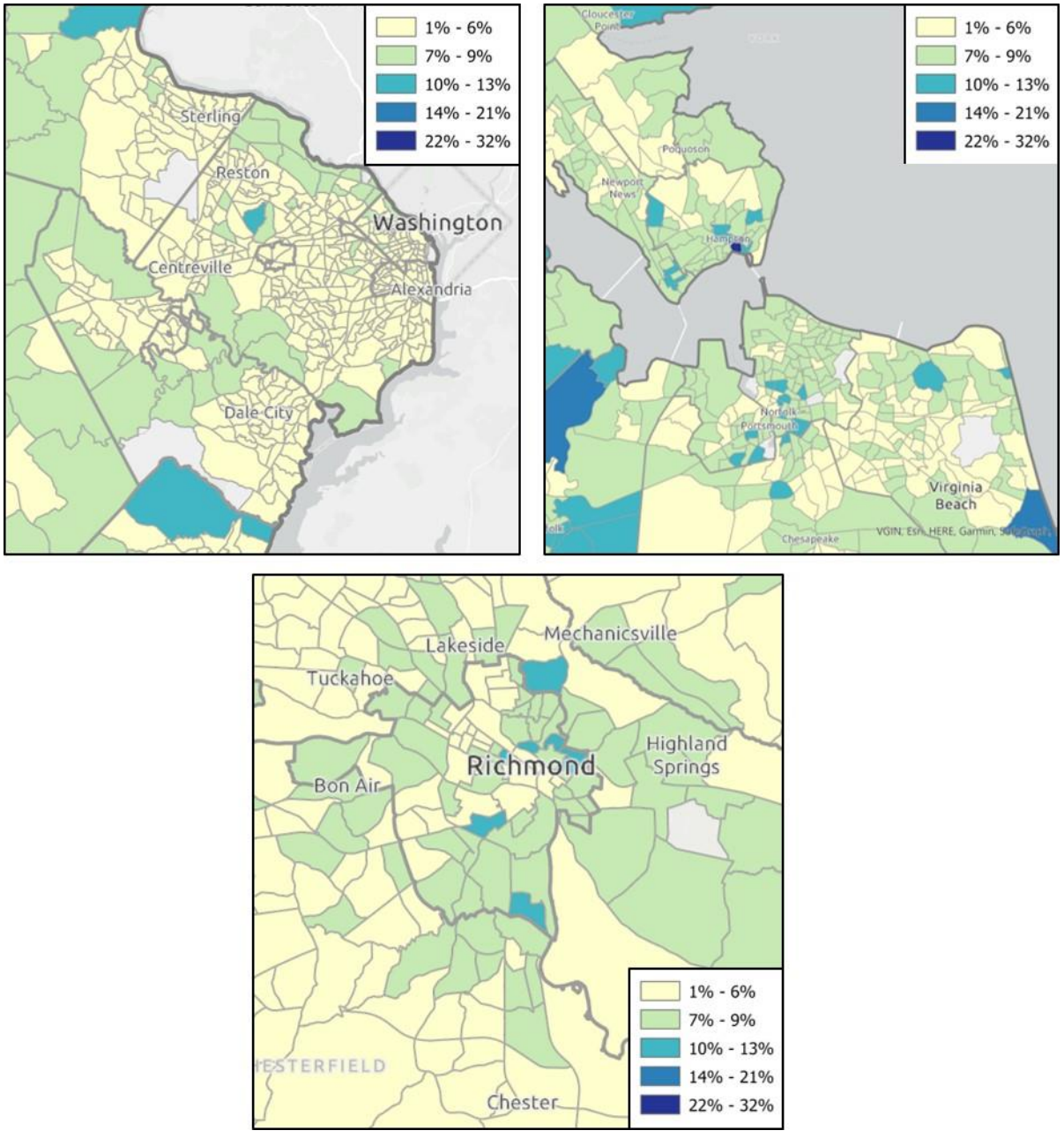
A detailed look at the LEAD data demonstrates that there are 76 Census Tracts in Virginia with an AEB-LI of at least 15%, more than twice the national average of 7% for households in that same income bracket. Of those, twelve are located in the Danville area. The other localities with at least six such Census Tracts are Mecklenburg County (8), Halifax County (7), and Accomack County (6). There are also 15 Census Tracts in Virginia that have an AEB-LI above 22%. This is over three times the national average energy burden for households in that same income bracket. (See detailed list in Appendix B).

[96] U.S. Census Bureau, 2022. Public Use Microdata Sample (PUMS).

[97] U.S. Census Bureau, 2022. TIGER/Line Geodatabases.

Map 1 suggests that AEB-LI percentages are relatively low in the state's metropolitan regions, compared to many rural areas. While this is generally accurate, Map 1.A shows that zooming into those regions reveals pockets of higher AEB-LI throughout each of those regions, particularly in parts of Hampton, Newport News, Norfolk, Portsmouth, and Richmond.

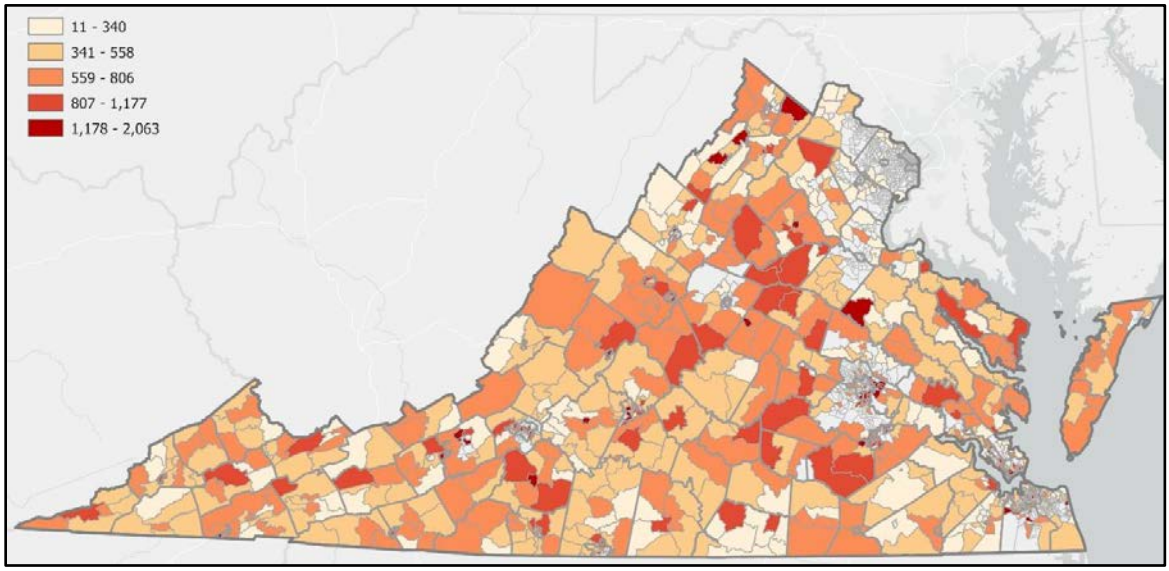
Map 1.A. Average Energy Burden of Low-Income Households (2018) – Metro Regions



We then identified the Census tracts in which the AEB-LI is above 6%, and those above 10%, to reflect the standard definitions of "High" energy burden and "Severe" energy burden, respectively. Within these AEB-LI High energy burden and AEB-LI Severe energy burden Census tracts we then calculated the total housing units, single-family homes (SFH) and multi-family housing units (MFH).

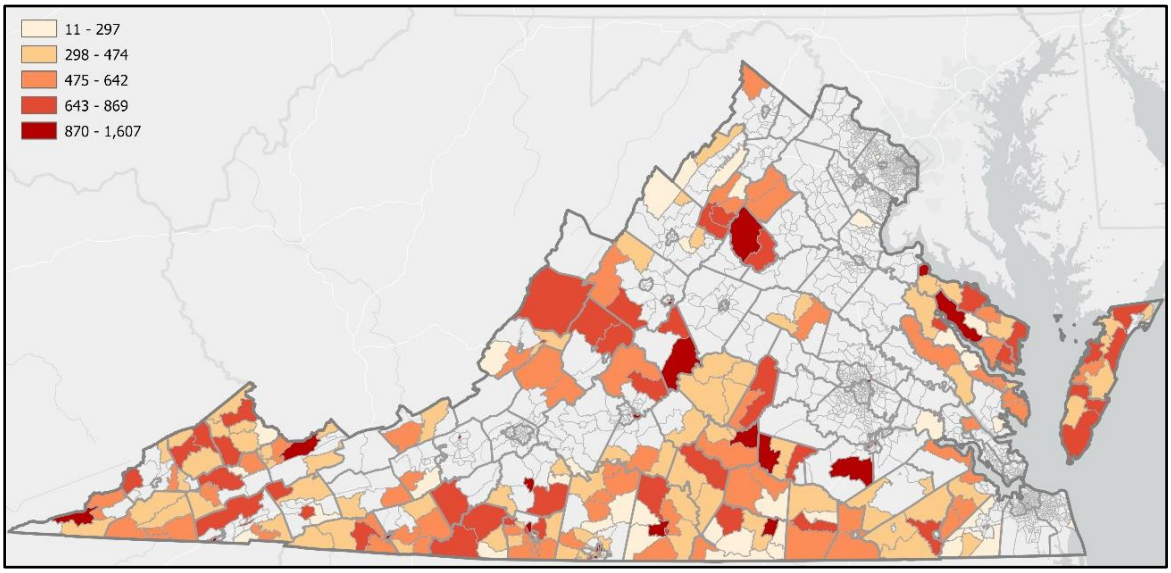
Maps 2 and 3 below show the number of housing units within Virginia Census tracts that have High or Severe average energy burdens, respectively, among their low-income households (0 - 80% AMI). Similar maps focused on single-family homes and multi-family units can be found in Appendix C.

Map 2. Housing Units in Census Tracts with High Low-Income Energy Burden (2018)



Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

Map 3. Housing Units in Census Tracts with Severe Low-Income Energy Burden (2018)

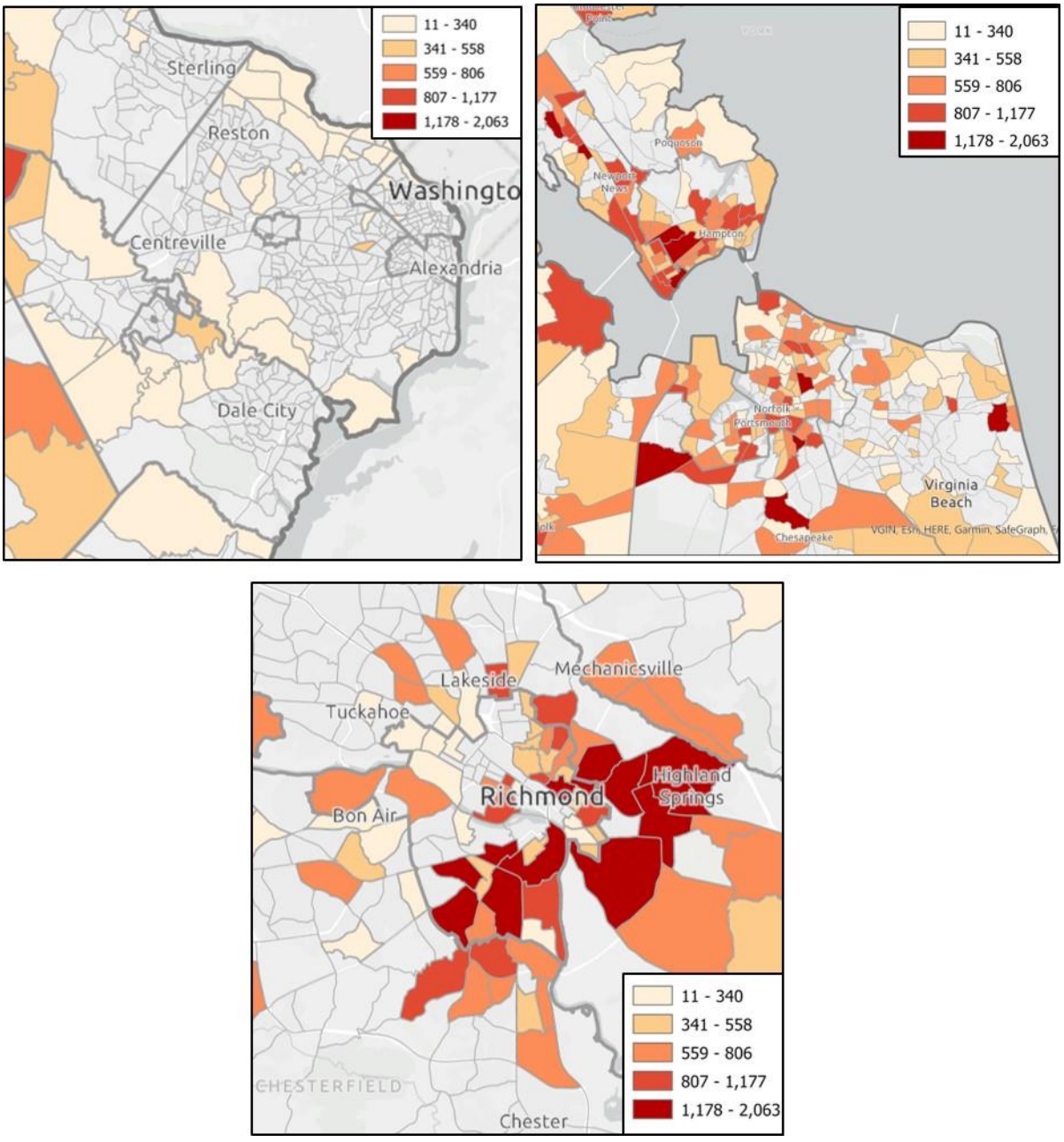


Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

Maps 2 and 3 demonstrate concentrations of High AEB-LI housing units in many rural areas of Virginia, similar to Map 1, along with pockets of Severe AEB-LI throughout much of the state. Many of these Severe AEB-LI tracts are found in SW Virginia, Southside Virginia, the Northern Neck, and the Eastern Shore, again consistent with Map 1. Map 2 also shows concentrations of households in High AEB-LI Census Tracts in some exurban areas outside of the Northern Virginia and Richmond metro regions.

Maps 2.A and 3.A identify housing units in High and Severe AEB-LI areas of the state's metro regions.

Map 2.A. Housing Units in Tracts with High Low-Income Energy Burden – Urban Regions

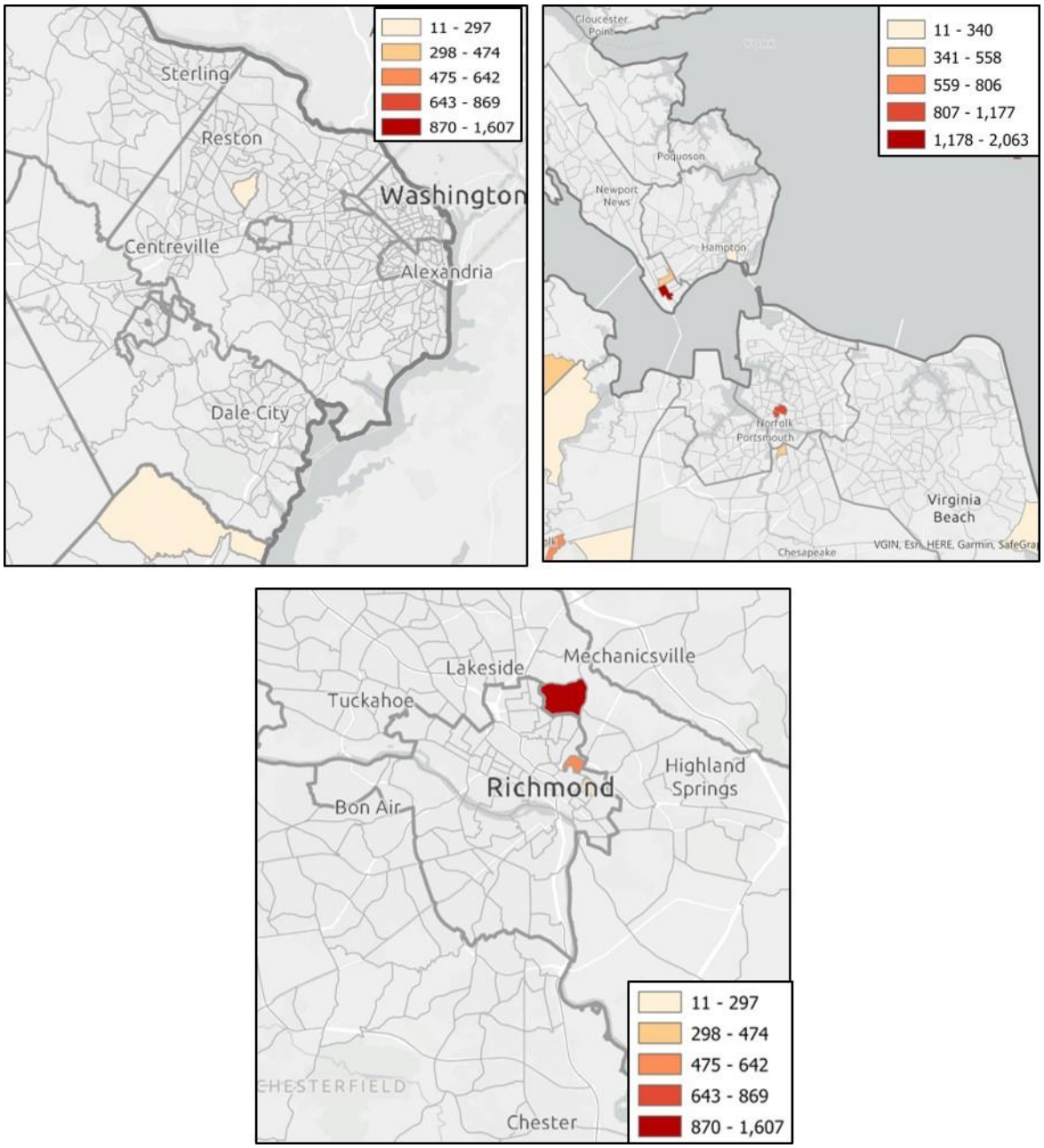


Map 2.A. shows significant concentrations of housing units in High AEB-LI Census Tracts in both the Hampton Roads and Richmond regions, but very little in the Northern Virginia region. In Hampton Roads

this includes large parts of the cities of Hampton, Newport News, Norfolk, and Portsmouth, among other parts of the region. In the Richmond area this includes much of the city's Southside, Northside, and East End areas, as well as portions of eastern Henrico County and northern Chesterfield County.

While the urbanized portions of the Hampton Roads and Richmond regions have large areas with High AEB-LI, Map 3.A. shows that very few of the Census Tracts in those regions have Severe AEB-LI.

Map 3.A. Housing Units in Tracts with Severe Low-Income Energy Burden (2018)



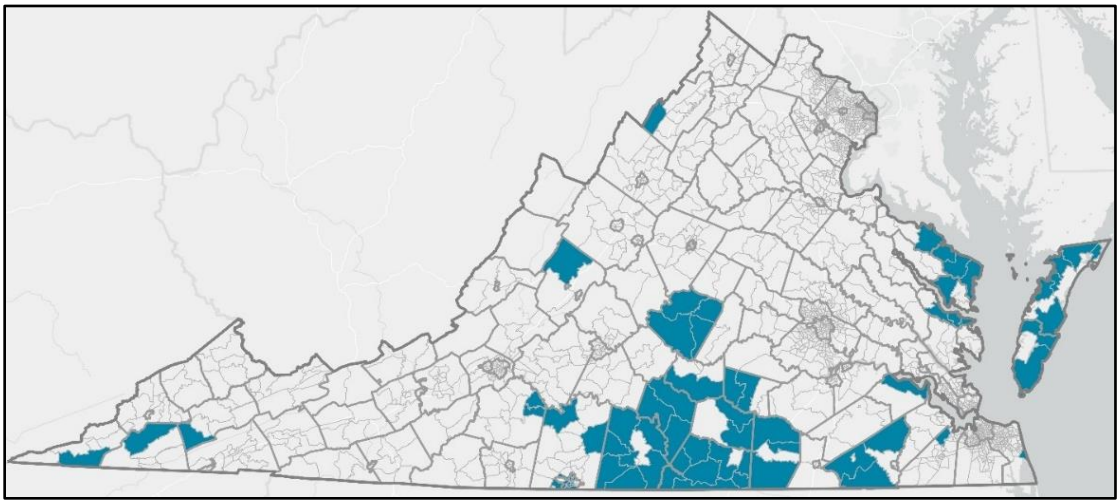
3.2. Discussion of Low-Income Energy Burden Findings

The housing data represented in Maps 2 and 3 shows that there are approximately 579,000 households in Virginia that have low-incomes (below 80% AMI) and are located in Census tracts with a High average low-income energy burden (above 6%). This includes roughly 436,000 single-family units and 143,000 multi-family units. Of these, about 154,000 total low-income housing households are located in Census tracts with a Severe average low-income energy burden (above 10%). This includes about 129,000 single-family units and 25,000 multi-family units. (Please note that the single-family plus multi-family units do not add up to the exact total units, due to rounding within the underlying data). For comparison, Census data estimates that there are about 3.25 million households in Virginia as of 2019.[98]

It is important to clarify that the household totals in the preceding paragraph do not represent an estimate of the total households that are actually both low-income and High or Severe energy burdened. Rather, they are low-income households located in Census tracts for which the average low-income energy burden is High or Severe. There are certainly some low-income households in those High or Severe AEB-LI tracts that do not have high energy burdens, just as there are likely many low-income households that do have High energy burdens but are located in tracts where the AEB-LI is not so high.

A closer examination of the 76 tracts with an AEB-LI of at least 15%, shown below in Map 4, indicates that about 10 of them have extreme concentrations of poverty, with anywhere from 48% to 94% of households below 80% AMI. However, the majority do not have extraordinary concentrations of low-income households. In fact, the average percent of households with incomes below 80% AMI in these 76 Census Tracts, 34.2%, is just a shade above the average of 32.9% for all Census Tracts in Virginia. Rather, the common thread among these Census Tracts with an AEB-LI of at least 15% is that almost all of them have an average annual energy cost (AAEC) that is much higher than the statewide average of $2,343. In fact, the average AAEC for those tracts ($3,717) is nearly 60% higher than the statewide average. In 14 of those Census Tracts the AAEC is more than double the statewide average, and in most of those the average energy burden is above 10% for all households. This suggests the opportunity to significantly reduce energy burdens in those areas through investments in low-income energy efficiency.

Map 4. Census Tracts with Average Low-Income Energy Burden above 15%



[98] U.S. Census Bureau. American Community Survey Data. 5-Year Estimates, 2017-2021.

4. Modeling Virginia's Future RGGI Income and Energy Efficiency Benefits

4.1. Understanding RGGI Policies and Trends

This section describes our methodology and assumptions for predicting future RGGI revenue for Virginia. As discussed in Section 1.3, participating states receive a set number of "allowances" based on their share of a regional emissions cap that goes down each year. Power plants in participating states must purchase these allowances at quarterly auctions, with each allowance permitting the emission of one short ton of CO_2.

The program includes three "auction mechanisms" that collectively ensure stability in the allowance market. The Minimum Reserve Price is the minimum price that allowances can be sold for at a RGGI auction. The Cost Containment Reserve (CCR) and Emissions Containment Reserve (ECR) are reserves of allowances that help provide market stability if the cost of reducing emissions is higher or lower than expected. The CCR allowances are made available for sale at an auction if the allowance price would otherwise exceed a set trigger price. Conversely, ECR allowances are withheld from sale at an auction, if the price would otherwise fall below a set trigger price.[99]

Virginia's base budget allowance began at 27,160,000 in 2021 and reduces by 840,000 per year, down to 19,600,000 in 2021.[100] However, RGGI announced in 2021 that there would be an "adjustment for banked allowances," which would adjust each state's allowances over the coming five years in order to account for an excess of allowances that had been privately banked from 2009-2020. The effect of this adjustment is a reduction of Virginia's allowances by 4,329,155 per year from 2021-2025.[101]

The ECR trigger prices, set by RGGI program operators, began at $6.00 when Virginia entered the market in 2021. They will increase by 7% per year, reaching $11.02 in 2030.[102] The CCR trigger prices began at $13.00 and will also increase by 7% per year, to $23.89 in 2030.[103] Over the eight auctions since Virginia joined RGGI, the auction clearing price has remained between the ECR and CCR trigger prices, with one exception. In late 2021, the auction price surged from $9.30 in the September auction to the CCR trigger price of $13.00 in the December auction, resulting in the release of 3.9 million allowances from the Cost Containment Reserve, including 888,829 for Virginia. Subsequent prices have remained close, but have not met, the 2022 CCR trigger price of $13.91, closing at $12.99 in the December 2022 auction.[104]

This information is summarized in Table 5, which identifies Virginia's base budget allowances, adjustments, resulting actual allowances, and the identified ECR and CCR trigger prices for each year from 2021-2030. The "net adjustments" column includes the aforementioned adjustment for banked allowances, which reduces Virginia's total by 4,329,155 per year from 2021-2025, as well as the additional 888,829 in allowances added to Virginia's total from the Cost Containment Reserve in 2021.

[99] The Regional Greenhouse Gas Initiative, 2021. RGGI 101 Fact Sheet.

[100] Virginia Legislative Information System, 2020. 9VAC5-140, Table 140-5A. CO2 allowance allocations.

[101] The Regional Greenhouse Gas Initiative, 2021. Third Adjustment for Banked Allowances Announcement.

[102] Virginia Legislative Information System, 2020. 9VAC5-140, Table 140-1B. CO_2 ECR Trigger Price.

[103] Virginia Legislative Information System, 2020. 9VAC5-140, Table 140-1A. CO_2 CCR Trigger Price.

[104] The Regional Greenhouse Gas Initiative, 2022. Allowance Prices and Volumes.

Table 5. Adjusted Virginia RGGI Allowance Totals and Price Trigger Points, 2021-2030

Year	Base Budget Allowances	Net Adjustments	Actual Allowances	ECR Trigger Price	CCR Trigger Price
2021	27,160,000	-3,440,326	23,719,674	$6.00	$13.00
2022	26,320,000	-4,329,155	21,990,845	$6.42	$13.91
2023	25,480,000	-4,329,155	21,150,845	$6.87	$14.88
2024	24,640,000	-4,329,155	20,310,845	$7.35	$15.92
2025	23,800,000	-4,329,155	19,470,845	$7.86	$17.03
2026	22,960,000	-4,329,155	18,630,845	$8.41	$18.22
2027	22,120,000	0	22,120,000	$9.00	$19.50
2028	21,280,000	0	21,280,000	$9.63	$20.87
2029	20,440,000	0	20,440,000	$10.30	$22.33
2030	19,600,000	0	19,600,000	$11.02	$23.89

Sources identified in preceding text and footnotes.

In order to model future RGGI revenue for Virginia, one must start with estimates for the future clearing prices. If those estimates at any point reach the ECR or CCR trigger prices shown above, then the total number of allowances sold would have to decrease or increase accordingly.

To date there have been very few attempts to model future RGGI clearing prices. The most notable attempt comes from a study prepared by ICF International, as part of RGGI's "second program review," which led to the development of RGGIs 2017 Model Rule.[105] This study modeled a lower projected RGGI allowance price curve that would rise from about $8 in 2023 to roughly $13 in 2030, and a higher projected curve starting at around $14 in 2023 and reaching $23 in 2030 (all prices in nominal dollars for those future years). This lower projected price curve remains above the ECR trigger price from 2021-2030, and the higher price curve remains below the CCR price.[106] While the actual RGGI auction prices were lower than ICF's modeled lower price curve through mid-2020, auction prices have been closer to ICF's modeled higher price curve since September 2021.

4.2. Modeling Future RGGI Clearance Prices and Virginia Revenue Scenarios

Given the recent clearing price trends, relative to the ICF's modeled price curves, it is reasonable to assume that RGGI clearance prices are likely to remain above the ECR trigger price, and below the CCR trigger price, from 2023 through 2030.[107] The CCR trigger has only been reached once since late 2015, as a result of the significant clearance price surge in the December 2021 auction. The ECR trigger price has

[105] The Regional Greenhouse Gas Initiative, 2022. Program Review.

[106] ICF International, 2017. DRAFT 2017 Model Rule Policy Scenario Overview.

[107] Shobe, W., 2022. University of Virginia. Personal communication. (December 8, 2022).

not been reached since it came into effect in January 2021. The modeled RGGI clearance prices from ICF do not reach the trigger prices, in either their low price or high price scenarios, from 2023 through 2030.

Given these assumptions, our Low-end and High-end Virginia RGGI revenue scenarios are as shown in Table 6. Both scenarios include the actual Virginia allowances sold, average clearing prices, and actual resulting RGGI revenue for 2021 and 2022. The Low-end, conservative scenario assumes that the average annual clearing price drops by 2.5% per year from the actual average of $13.59 in 2021 to $11.10 in 2030. This is the steepest possible average annual drop in prices without triggering the ECR at any point. The High-end, more aggressive scenario assumes that the average annual clearing price will increase by 5% a year, to $20.07 in 2030, which would not exceed the CCR at any point. All prices are listed in nominal dollars for their respective years.

With the assumption that neither the ECR or CCR price is reached, the allowances sold each year equal the "Actual Allowances" shown in Table 5. The minimum revenue is then calculated as the allowances sold times the Low average clearing price, while the maximum revenue is the allowances sold times the High clearing prices. (Again, actual values are shown for 2021 and 2022, while 2023-2030 are modeled).

Table 6. Modeled Allowances, Clearing Prices, and Virginia Revenue, Low and High Scenarios

Year	Allowances Sold	Average Clearing Price (Low)	Average Clearing Price (High)	Estimated Revenue – Low ($Millions)	Estimated Revenue – High ($Millions)
2021	23,719,674	$9.47	$9.47	$227.64	$227.64
2022	21,990,845	$13.59	$13.59	$298.80	$298.80
2023	21,150,845	$13.25	$14.27	$280.59	$302.17
2024	20,310,845	$12.92	$14.98	$262.72	$304.70
2025	19,470,845	$12.59	$15.73	$245.58	$306.72
2026	18,630,845	$12.28	$16.52	$229.12	$308.18
2027	22,120,000	$11.97	$17.34	$264.82	$383.59
2028	21,280,000	$11.67	$18.21	$248.39	$387.48
2029	20,440,000	$11.38	$19.12	$232.62	$390.79
2030	19,600,000	$11.10	$20.07	$217.49	$393.47
Totals	**208,713,899**			**$2,507.77**	**$3,303.54**

Source: RGGI data and analysis by authors

As a result of the methods outlined above, the estimated total RGGI revenue for Virginia from 2021-2030 is $2.5 billion in the Low scenario, and $3.3 billion in the High scenario. The resulting HIEE funding, 50% of the total, is therefore $1.25 billion (Low scenario) to $1.65 billion (High scenario).

4.3. Modeling Household Energy Savings from HIEE Energy Efficiency Investments

In this section we analyze available data on the performance of the HIEE energy efficiency programs to-date, and estimate the projected energy and customer bill savings that the programs could produce through the year 2030. These estimates are presented in two scenarios – Low revenue and High revenue – based on the potential range of RGGI-generated HIEE revenue from the year 2021-2030. As the revenue projections in the prior section are in real, nominal dollars for the years 2021-2030, all cost estimates in this section incorporate reasonable assumptions for inflation over that same period. The initial steps in this modeling process, conducted separately for both revenue scenarios, are as follows:

- Identify a reasonable assumption for how future HIEE revenue would be distributed across the Weatherization Deferral Repair (WDR) and Affordable and Special Needs Housing energy efficiency (ASNH-EE) funds, as well as the distribution of WDR funding across single-family (WDR-SFH) versus multi-family (WDR-MFH) housing projects.
- Identify the average cost per unit upgraded via the ASNH-EE, WDR-SFH, and WDR-MFH projects completed to-date, and project those costs forward through 2030 at a reasonable inflation rate.
- Divide the annual funding estimates for each project type – ASNH-EE, WDR-SFH, and WDR-MFH – by their respective projected costs per unit, producing an estimated number of units receiving energy efficiency or weatherization deferral upgrades, per year (2021-2030), via each program.

Here one must note that there is a natural lag time between when the state receives RGGI funding and when the subsequent HIEE funds result in completed energy efficiency projects. As previously discussed, the revenue generated for the HIEE program since Virginia joined RGGI equals nearly $252 million ($526.5 in RGGI auction revenue times 50%, minus the $11.4 million diverted to the Hurley flood relief fund). But as of December, 2022, DHCD had spent or committed only $37.08 million of those funds (29.16 to ASNH-EE and $7.92 to WDR), with another $80 million in ASNH-EE funds to be released in FY ‘23. Therefore, in our analysis, the number of units identified for each year corresponds to the estimated number of units that could be upgraded with the revenue generated that year, with an understanding that the actual energy efficiency projects would take place within the subsequent couple of years.

Once the projected number of units upgraded per year has been calculated, the next steps are to estimate the resulting energy efficiency and customer savings benefits. These savings are calculated in the aggregate, based on the total number of housing units that could receive energy efficiency upgrades via the projected HIEE revenue through 2030, and represent the annual energy and customer bill savings benefits resulting from those energy efficiency investments. This is calculated as follows:

- Multiply the number of housing units that could be upgraded, per project type (ASNH-EE, WDR-SFH, and WDR-MFH), by their corresponding estimated annual energy savings per housing unit, in millions of British thermal units (MMBTUs).
- Convert the estimated total annual energy savings from MMBTU to kilowatt-hours (kWh), and multiply the resulting estimated electricity savings times an estimated electricity rate ($ / kWh) for the year 2030, projected forward based on past electricity rate trends.

A key assumption, discussed further below, is that all of the energy savings from the HIEE programs are in the form of reduced electricity consumption. Another key assumption of this analysis is that every WDR project results in a subsequent WAP project, as is the intent of the WDR program, with ensuing energy efficiency benefits. These steps are discussed in more detail in the following sections.

4.3.1. Estimating Total Units to be Upgraded with Future HIEE Program Funds

As noted in Section 1, Table 2, the initial distribution of HIEE funds for FY 2021 was 60% to WDR and 40% to ASNH-EE. In FY 2022 these percentages were essentially reversed, with 60% of funds going to ASNH-EE, 30% to WDR, and 10% to a proposed "Housing Innovations Partnerships" grant program.

Of the HIEE funds spent or committed to-date, roughly 80% has gone to ASNH-EE, versus 20% to WDR. This does not include the additional $80 million in ASNH-EE funds announced in late 2022, which will skew the percentage even higher towards that program. Projecting forward, the amount of weatherization deferral repair work that can be completed is constrained by both the capacity of the state's weatherization provider network as well as the availability of federal WAP funds. While Virginia has experienced a substantial increase in WAP funding from the Bipartisan Infrastructure Law, that is a one-time source of additional funds that is currently only available until expended.

Considering these factors, our model assumes that 85% of HIEE funds generated from 2021-2030 will be dedicated to the ASNH-EE program, and 15% to the WDR program. This amount of funding would still support substantial ongoing weatherization deferral support, as indicated in the final modeling results.

The next critical assumption is the distribution of WDR funds between single-family and multi-family projects. The aforementioned total of $7.92 million in WDR expenditures thus far includes both funds already spent and the estimated costs of projects currently approved and in-progress, including both single-family and multi-family projects. However, detailed cost data is only available for the $4.60 million that has actually been spent thus far. Of those funds, 86.5% ($4.02 million) has been spent on single-family WDR projects, and 13.5% ($627,000) on multi-family projects.[108]

Moving forward, we assume that WDR funding will be split 85% to single-family projects and 15% to multi-family. This results in an overall HIEE funding distribution of 85% to ASNH-EE, 12.75% to WDR-SFH, and 2.25% to WDR-MFH.

Data on the estimated cost per unit for the three HIEE program types is based on information released by DHCD. For ASNH-EE, a July 2021 announcement indicated that $6.2 million in ASNH-EE funds would be spent across 11 projects, supporting a total of 707 units.[109] A subsequent announcement in January 2022 included $22.96 million in ASNH-EE funds, supporting 1,682 units across 25 projects.[110] Combining the numbers from these two announcements results in an average cost per unit of $12,190. For WDR, the aforementioned totals provided by DHCD indicate an average cost per unit of $13,260 for WDR-SFH and $2,170 for WDR-MFH.

Our model uses these totals as the average cost per unit for the respective programs in 2021 and 2022. For future years we apply a 3% average annual increase to each of these costs. This assumption is based on analysis from CBRE, one of the country's leading real estate services and investment firms, which

[108] Virginia DHCD, 2022. Personal communication from Aaron Shoemaker, Program Administrator, Energy Efficiency Office. (December 8, 2022).

[109] Virginia DHCD, 2021. Governor Northam Announces Over $21 Million in Affordable and Special Needs Housing Loans.

[110] Virginia DHCD, 2022. Governor Northam Announces Over $60 Million in Affordable and Special Needs Housing Loans.

indicates a 14% increase in construction costs from 2021-2022 and anticipates that price escalation "should stabilize to the 2% - 4% range in 2023 and 2024, on par with historical averages."[111] Projecting the per-unit project costs forward at 3% per year, beginning in 2023, results in averages of $15,442 for ASNH-EE, $16,797 for WDR-SFH, and $2,749 for WDR-MFH in the year 2030.

With these assumptions in place for the annual HIEE revenue scenarios, distribution of revenue across project type, and average costs per unit, we can then calculate an estimated number of units across each program that could be upgraded with anticipated funding through the year 2030. While the more detailed calculation tables can be seen in Appendix D, the final results are summarized in Table 7 below.

Table 7. Estimated Units Upgraded via HIEE Programs, per 2021-2030 RGGI Revenue Scenario

Revenue Scenario	ASNH - EE	WDR - SFH	WDR - MFH	Total Units
Low ($1.24 billion)	78,373	10,806	11,653	100,832
High ($1.64 billion)	101,833	14,041	15,141	131,015

As discussed above, there is a natural lag time between when the state receives RGGI funding and when the subsequent HIEE funds result in completed energy efficiency projects. Therefore, the totals shown above correspond to the estimated number of units that could be upgraded with the total revenue generated from 2021-2030, with an assumption that the actual energy efficiency projects would take place within the subsequent couple of years.

4.3.2. Estimating Energy Consumption and Bill Savings from HIEE Energy Efficiency Investments

Having determined the estimated number of units to be upgraded under each funding scenario, we can now project the resulting energy efficiency and customer savings benefits.

First, we used data from the Virginia Center for Housing Research at Virginia Tech, which completed a study of the HIEE program for DHCD in the fall of 2022. The Virginia Tech study found that the WDR-SFH projects that had been completed by that time had generated an average energy savings of 37.1 MMBTU per year, versus 4.8 MMBTU per year for multi-family units in WDR-MFH projects.[112]

As noted above, these modeled savings incorporate the resulting energy efficiency upgrades that would occur as the completed WDR project is further weatherized, with federal funds, via the WAP program. The additional costs of those WAP projects are not incorporated here, as the intent of this study is to evaluate the benefits of the RGGI funding that Virginia routes through HIEE, and the capacity of the WDR program to unlock federal WAP dollars for low-income Virginia residents is one such benefit.

The Virginia Tech study also modeled the energy savings resulting from the various types of ASNH-EE projects. As discussed in Section 1.4.1, any project receiving ASNH funds can be assumed to also be receiving the Low-Income Housing Tax Credit (LIHTC), administered through Virginia Housing. Projects receiving the LIHTC tax credit in Virginia are required to achieve a certain level of energy efficiency performance, based on their project type (new construction, substantial rehabilitation, or adaptive

[111] CBRE, Inc. 2022. 2022 U.S. Construction Cost Trends.

[112] Virginia Center for Housing Research, Virginia Tech, 2022. *Housing Innovations in Energy Efficiency Report*.

reuse), and projects that receive ASNH-EE funds via the HIEE program are expected to reach even more rigorous energy efficiency benchmarks (see details in Table 3).

Therefore, the energy savings from a given ASNH-EE project can be calculated based on that margin between the LIHTC requirements and the ASNH-EE requirements. The Virginia Tech study found those marginal savings to be 29% for New Construction projects, 20% for Substantial Rehabilitation, and 14% for Adaptive Reuse. The Virginia Tech study also calculated an estimated average per-unit energy consumption, in energy use intensity (EUI), customer bill amounts (dollars per year) and greenhouse gas emissions (CO_2-equivalent, or CO_2-e) for each ASNH-EE project type.

Table 8. Annual per Unit Energy Performance of ASNH-EE Projects vs. LIHTC Requirements

Project Type	Energy Savings (EUI)	Energy Savings (%)	Bill Savings ($)	GHG Savings (tons CO_2-e)
New Construction	6.97	29%	$200	1.6
Substantial Rehab	7.94	20%	$103	0.8
Adaptive Reuse	6.90	14%	$154	1.3

Source: Virginia Center for Housing Research, Virginia Tech, 2022. Housing Innovations in Energy Efficiency Report.

Based on the results from Table 8, and employing the current carbon coefficient for electricity in Virginia (626.3 lbs / MWh),[113] we were able to calculate the average annual energy savings for housing units upgraded via each ASNH-EE program. For example, according to the Virginia Tech study, an ASNH-EE new construction project emits 1.6 tons CO_2-e / year less than an equivalent project meeting only the LIHTC energy efficiency requirements. The aforementioned carbon coefficient rate for Virginia electricity of 626 lbs / MWh translates to 3193 kWh / ton. Multiplying this carbon ratio times the 1.6 ton difference in emissions results in an annual energy savings of 5,110 kWh from the ANSH-EE new construction unit. At a conversion rate of 3,412 Btu / kWh, this equals 17.43 MMBTU.

Replicating this same process for substantial rehabilitation and adaptive reuse projects resulted in estimated annual energy savings per housing unit of 8.72 MMBTU and 14.16 MMBTU respectively. Using the detailed data on units per ASNH-EE housing type from the DHCD's July 2021 and January 2022 press releases, we then calculated a weighted average of 13.97 MMBTU savings from all ASNH-EE units, relative to equivalent low-income housing units that meet the LIHTC performance standards only.

With the average annual energy savings calculated for ASNH-EE, WDR-SFH, and WDR-MFH projects, we were then able to calculate the total energy savings (MMBTU) and electricity savings (kWh) for the year 2030, for both revenue scenarios. To convert electricity savings to customer bill savings required an estimated cost of electricity in the year 2030. We calculated this estimate based on data from the U.S. Energy Information Administration, which shows that the average retail price of electricity in Virginia has increased from 7.79 cents / kWh in 2002 to 11.96 cents / kWh in 2021, for an average annual growth rate of 2.17%. Extrapolating that same growth rate out produces an estimated average price of 15 cents per kWh in 2030. Multiplying that projected price times the estimated electricity savings produced the estimated total and average per unit customer bill savings shown in Table 9.

[113] U.S. Environmental Protection Agency, 2022. eGrid 2020. See data for SRVC sub-region.

Table 9. Total Units Upgraded (2021-2030) and Annual (Year 2030) Energy and Bill Savings

RGGI / HIEE Revenue Scenario	Units Upgraded	Total Energy Savings (MMBTU)	Total Energy Savings (MWH)	Total Bill Savings ($Millions)	Bill Savings / Unit ($)
Low ($1.24 billion)	100,832	1,551,322	454,666	$68.20	$676
High ($1.64 billion)	131,015	2,015,703	590,769	$88.62	$676

Source: Calculations by authors, using energy savings data from Virginia Center for Housing Research, Virginia Tech, 2022. Housing Innovations in Energy Efficiency Report.

To reiterate, the energy and customer bill savings shown above are based on the total number of housing units that could receive energy efficiency upgrades via the projected HIEE revenue from 2021 through 2030. These are annual values, representing the projected energy and customer bill savings benefits in the year 2030, as a result of the energy efficiency investments funded by HIEE. These annual energy savings would continue in subsequent years (i.e., beyond 2030), with resulting customer bill savings increasing along with the average price of electricity. Annual energy and customer bill savings realized in the earlier years (i.e., 2021-2029) would be proportional to the number of HIEE energy efficiency projects completed by a given year, and the average electricity price at that time.

A key assumption of this analysis is that virtually all residential energy use in the year 2030 comes in the form of electricity, with direct consumption of natural gas or other fossil fuels for heating, water heating, etc. having been largely phased out in the residential sector. This assumption is in part for simplicity's sake. To include an estimated percentage of energy savings that would come from direct fossil fuel use, rather than electricity, would introduce significant additional complexity to the analysis, without substantively impacting the final results. This assumption is also reflective of a trend towards electrification in new and renovated housing, particularly for subsidized housing units.

5. Economic Impact Analysis of Virginia's HIEE Program

An economic impact model describes how a change in economic activity in one or more industries can influence a broader regional economy. The model developed for this analysis utilizes IMPLAN, an input-output modeling system. An input-output model traces a change in spending from the source backwards through the supply chain, identifying how much of the spending is likely to remain inside the region with suppliers and workers, and how it will be spent in turn. The resulting dollar figures describe how the original change in economic activity reverberates through a regional economy, making an impact greater than the initial dollar figure.

The total economic impact of a given economic activity is comprised of several dimensions, as each stage of that activity is comprised of resources that go towards supplies, labor, profit, and taxes. The components of the total impact are divided into Employment, Labor Income, and Value Added. Value Added refers to the amount that a good increases in value at each step of the production process, after subtracting the cost of materials. More broadly, the value added of an industry is the difference between its gross sales and the cost of its supplies (including raw materials, energy, and services).[114]

Each component of economic impact flows from one of three possible stages in the economic process.

1. Direct impacts: Direct impacts are dollars that come from the initial source or change. In this case, the direct impacts are those that flow directly from HIEE funds.
2. Indirect impacts: These impacts flow from an industry's "backward linkages," or the relationship an industry has to its supply chain. For example, a bakery relies on supplies and materials produced by grain farmers, flour producers, and packaging manufacturers. An increase in demand at the bakery will influence purchases from those suppliers.
3. Induced impacts: Labor income changes allow households that receive that labor income to spend additional money on wants and needs. Induced impacts refer to the new spending that happens as a result of income changes spurred by direct and indirect impacts.

The direct impact constitutes the largest component of economic impact. However, indirect and induced impacts represent an essential component of a market economy, as they demonstrate the effects of backwards linkages, supply chains, and household spending that occur in response to direct impacts.

Economic impact analyses should not be considered a cost-benefit analysis. The impacts described may be considered benefits to one industry and costs to another. Impact analysis describes economic activity flowing from a change in production. The input-output modeling used in economic impact analysis is not able to trace the path of each dollar after it leaves the region. Inter-regional economic activity, where spending happens between economic regions, is not captured. Further, input-output models are static. They model changes in demand using existing knowledge of supply chains, but they do not model how those changes may increase or decrease the availability and cost of supplies and labor.

[114] U.S. Bureau of Economic Analysis, 2006. What Is Industry Value Added?

5.1. Model Inputs and Outputs

An economic impact begins with a change in economic activity. In this case, we are modeling the spending associated with HIEE revenue generated between 2021 and 2030. After identifying the total HIEE funding for each year, we can divide that funding by program (WDR and ASNH-EE) and, ultimately, categorize each program's dollars by industry equivalent IMPLAN category (e.g., construction of new multifamily residential structures). Similar efforts have classified RGGI-related energy efficiency spending by states in IMPLAN's construction and maintenance categories.[115] Those dollars are entered into the model using the relevant industry code and dollar year.

The model uses a combination of industry and employment multipliers, household spending estimates, and regional purchasing coefficients, or estimates of the percentage of a region's demand for a good met by production within that region. Together, these tools are used to estimate how the inputs – $1.24 billion to $1.64 billion in total – will change demand for suppliers, change demand for labor, and change household spending patterns. The results are expressed in 2022 dollars.

5.2. Economic Impact Analysis Results

The anticipated output of HIEE funding from 2021 through 2030—between $1.24 billion and $1.64 billion – would have a statewide impact between $2.03 and $2.67 billion (see Table 10).

Each dollar dedicated to the HIEE program flows through a chain of workers, manufacturers, and suppliers inside and outside of Virginia. Each dollar that leaves the state is considered economic leakage. The dollars that remain inside Virginia, passing from contractor to supplier to manufacturer to worker, constitute what we describe as the economic impact of the original event or spending.

For every $1.00 of HIEE funds spent, the total impact is between $1.656 and $1.658—the original $1.00 plus another $0.66 generated through indirect and induced effects (see Table 11). This means that HIEE program spending has a "multiplier effect" of 1.66, which is comparable to those of the following industries in Virginia:[116]

- Air transportation 1.666
- Wood windows and door manufacturing 1.661
- Glass container manufacturing 1.659
- Paper mills 1.654
- Electric power generation - Solar 1.651
- Electric power generation - Hydroelectric 1.634
- Electric power generation - Fossil fuel 1.619

These multipliers do not indicate that the industries have a net benefit or cost. They describe the ways that dollars flow backwards through the supply chain and worker households inside the region.

[115] Hibbard, P., et al., 2018. The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States.

[116] IMPLAN, 2021. Estimates of Industry Multipliers in Virginia.

The HIEE program's total economic impact is summarized in Table 10. Please note that the table does not include every element of economic impact, and some elements are subcategories of others. For example, Labor Income is a component of Value Added.

Table 10. Estimated Economic Impacts of the HIEE Program in Virginia, 2021 through 2030

Revenue Scenario	Output	Value Added	Labor Income	Employment [a]
Low	$2.03 Billion	$1.32 Billion	$834 Million	1,552
High	$2.67 Billion	$1.75 Billion	$1.11 Billion	2,115

Sources: CURA modeling and analysis of VCU projections of HIEE program spending

[a] *Figure represents new jobs across 10-year study period.*

The impact of HIEE-related spending from 2021 to 2030 will be a function of how much money is spent, and when. In Section 4 we modeled the estimated Low and High ranges of annual RGGI revenue, 50% of which will go to the HIEE program, based on the amount of CO_2 allowances available each year and a reasonable estimate of the potential range of allowance prices. As discussed in that section, the HIEE revenue generated from a given year's RGGI auction allowances will fund a certain amount of energy efficiency upgrades via the WDR and ASNH-EE programs over the subsequent years. This allows for an estimation of the economic impacts of that spending on a year-by-year basis.

The estimated annual economic impacts range between $200 million and $300 million each year, resulting in the aforementioned cumulative effect of between $2.0 billion (Low scenario) and $2.7 billion (High scenario), as shown in Figure 5.

Figure 5. Cumulative Economic Impact of HIEE Expenditures, 2021 – 2030

Sources: VCU model of estimated annual RGGI revenue for Virginia (see Section 4)

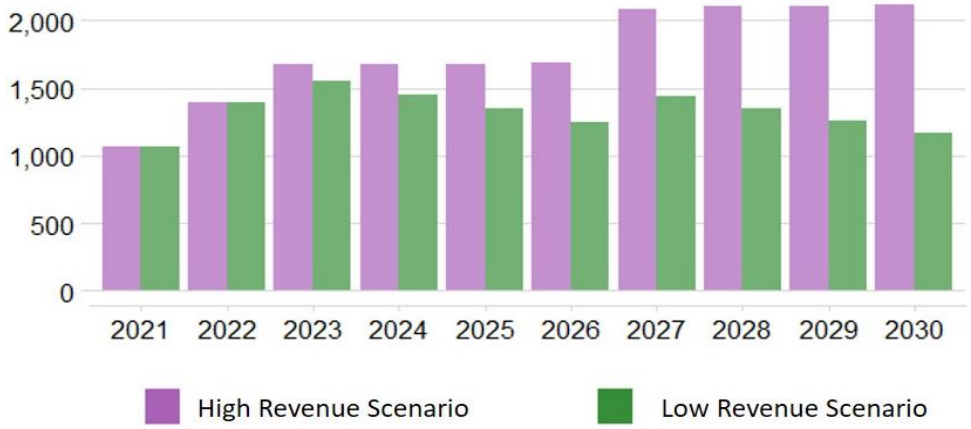
The total impact includes $1.32 (Low RGGI revenue scenario) to $1.75 billion (High revenue scenario) in Value Added across the 10-year period. Value added can be considered a measure of contribution to Virginia's GDP. The Value Added impact of the HIEE program generates an average annual contribution of $132 to $175 million to the state GDP, or around 0.02% to 0.03% of the 2021 GDP.[117]

[117] U.S. Bureau of Economic Analysis, 2022. What Is Industry Value Added?

We estimate that $0.83 to $1.11 billion of the value added would go towards Labor Income, which includes all employee compensation (salaries, benefits, payroll taxes) and "proprietor income" (i.e., payments received by self-employed individuals and unincorporated business owners).[118] This labor income across 10 years would create and sustain 1,552 to 2,115 jobs, at approximately $52,500 to $53,500 per job. The remainder of the value added would go towards corporate profits, capital depreciation, and taxes, and is treated as leakage.

Unlike the dollar-based impact figures, employment is not able to be stacked year-over-year in a cumulative manner. After the change in economic activity supports the job, adding it to the total year-after-year would misrepresent the impact. Figure 6 shows the number of jobs that the HIEE program would support over the 10-year period, as a function of the amount of revenue generated that year.

Figure 6. Annual Employment Supported by HIEE Expenditures, 2021 – 2030



Sources: VCU model of estimated annual RGGI revenue for Virginia (see Section 4)

Table 11 breaks down the direct, indirect, and induced impacts of projected HIEE funding through 2030. Indirect and induced impacts total $806 million to $1.06 billion over 10 years, roughly 40% of the aforementioned total economic impacts under the Low and High revenue scenarios. Those impact phases represent dollars that have moved through the initial round of business spending to other suppliers in Virginia (indirect) and spending by workers shopping in Virginia (induced).

Table 11. Summary of HIEE Direct, Indirect, and Induced Impacts, 2021 through 2030

Revenue Scenario	Direct	Indirect	Induced	Total
Low	$1.22 Billion	$326 Million	$480 Million	$2.03 Billion
High	$1.61 Billion	$422 Million	$636 Million	$2.67 Billion

Sources: CURA modeling and analysis of VCU projections of HIEE program spending

[118] Clouse, C., 2020. IMPLAN – Support. Understanding Labor Income (LI), Employee Compensation (EC), and Proprietor Income (PI).

The direct impact constitutes the largest component of economic impact. However, the indirect and induced impacts together account for about 40% of the total impact in each scenario, demonstrating the effects of backwards linkages, supply chains, and household spending that are essential components of a market economy. The induced impact outpaces the indirect impact, highlighting the importance of household spending in the Virginia's economy. Consumer spending often occurs close to home, and the dollars continue to ripple through the economy.

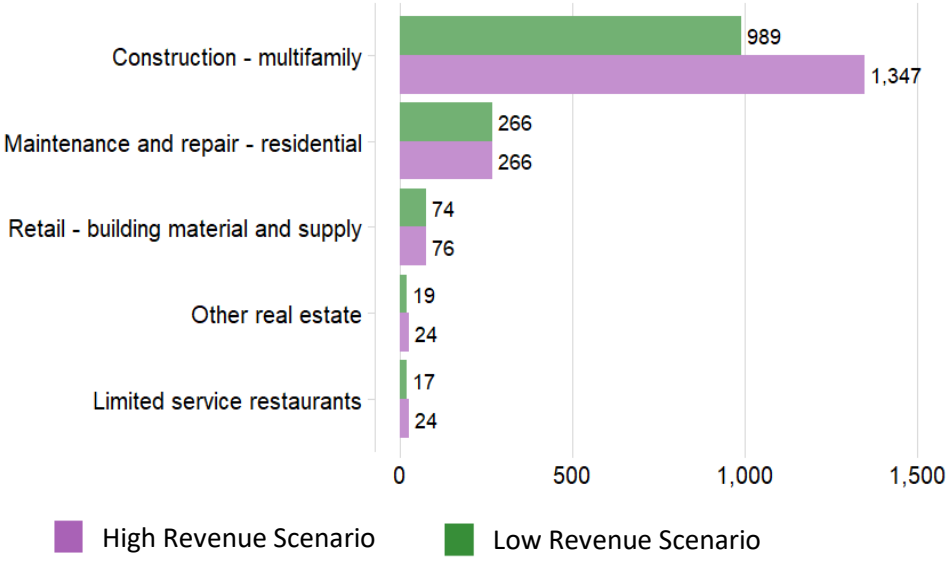
Table 12 merges the information in the previous two tables, demonstrating in greater detail how the various elements of economic impact (employment, labor income, and value added) are distributed across the direct, indirect, and induced components of that impact, per the HIEE revenue scenarios.

Table 12. Summary of HIEE Impact Components, 2021 - 2030 (Low vs. High Scenarios)

Impact	Employment	Labor Income ($Millions)	Value Added ($Millions)
Direct	1,069 - 1,457	$581 - $774	$849 - $1,128
Indirect	217 - 233	$102 - $133	$186 - $240
Induced	311 - 424	$150 - $199	$288 - $382
Total	1,552 - 2,115	$834 - $1,106	$1,323 - $1,750

The indirect effects of HIEE funding would create and support 217 to 233 jobs through 2030. The induced effects – those generated by the new household spending that accompanies increases in labor income – would support 311 to 424 jobs through 2030. The influence of those effects is visible in the industries the model estimates will see the greatest increase in employment, such as the increases in retail and restaurant employment shown in Figure 7 below.

Figure 7. Industries with Largest Employment Impact



Sources: VCU model of estimated annual RGGI revenue for Virginia (see Section 4)

6. Summary and Conclusions

The research presented here has demonstrated the vast scope of the low-income energy burden challenge in Virginia, as well as the potential to significantly mitigate those energy burdens through continued participation in the energy efficiency programs funded by Virginia's participation in RGGI.

Hundreds of thousands of low-income households in Virginia experience "High" or "Severe" energy burdens, based on the percent of their incomes that are spent on home energy costs. This energy burden challenge does not sort out along geographic, demographic, or political lines. Concentrations of severe energy burden can be found throughout much of Virginia's rural areas, from the farthest corner of Southwest Virginia to the Eastern Shore, as well as in some of the state's most urban neighborhoods. This includes pockets of extreme energy burden, where low-income households are spending over 20% of their incomes on home energy costs. At these high levels, energy burden is not merely a financial challenge, but brings with it a degree of energy insecurity that threatens residents' health and safety.

Existing federal, state, and utility-sponsored energy efficiency programs – without RGGI – are insufficient to address the vast scope of the energy burden problem in Virginia. The variety of tax credits and financial incentives available to support residential energy efficiency, including the recently adopted or expanded tax credits under the federal Inflation Reduction Act, are largely inaccessible to low-income Virginians who live in rental housing and/or cannot afford even the subsidized up-front costs of energy-efficiency investments. The long-standing federal WAP and LIHEAP programs provide meaningful weatherization services for low-income residents, but even with increased funding under the Bipartisan Infrastructure Law they only address a tiny portion of the problem. While recent Virginia laws direct investor-owned utilities to invest significant funding into achieving ambitious energy-efficiency targets, only 15% of those funds are required to support Low- and Moderate-Income households.

The energy efficiency funding generated through Virginia's participation in RGGI vastly exceeds that of these other existing programs. While the aforementioned federal and state / utility programs will provide less than $55 million per year over the coming years, Virginia's RGGI revenue has already generated $250 million for low-income energy efficiency programs in just two years (2021-2022). If Virginia remains in the RGGI program through 2030, then we project the total funds raised for low-income energy efficiency to be between $1.24 and $1.64 billion over the course of the decade.

Using available data from the state, and a recent analysis from Virginia Tech, we were able to estimate the reduced energy consumption and customer bill savings that these future RGGI energy efficiency funds could provide. According to our calculations, Virginia's projected RGGI revenue through 2030 could eventually lead to energy efficiency improvements for anywhere from 100,000 to 130,000 low-income homes. The resulting energy savings would be between 1.56 and 2.01 trillion Btu per year, or 455,000 to 591,000 MWh of electricity. This would result in $68 to $89 million in customer bill savings per year, at an average of $676 per year per household.

Finally, we estimate that spending the projected RGGI funds through 2030 would have a statewide economic impact of between $2.03 and $2.67 billion. These findings indicate a "multiplier effect" of 1.66, meaning that every dollar invested in low-income energy efficiency generates an additional $0.66 in indirect and induced impacts. The estimated total impact includes $1.32 to $1.75 billion in Value Added across the 10-year period, which would represent an increase of 0.02% to 0.03% to the state's GDP. We estimate that the Labor Income component of that Value Added ($0.83 to $1.11 billion) would create and sustain 1,552 to 2,115 jobs, at approximately $52,500 to $53,500 per job.

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Appendix A. Energy Burden Mapping Methodology

Low-Income Energy Affordability Data (LEAD)

The US Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) developed the Low-Income Energy Affordability Data (LEAD) Tool, to help users examine household energy characteristics in relation to household income levels. The LEAD Tool provides three income models to depict income levels: Area Median Income (AMI), Federal Poverty Level (FPL), and State Median Income (SMI). For mapping purposes of this study, AMI was chosen to account for income variations across Virginia, and to establish the threshold of "low-income" defined as income below 80% AMI.

At the time of the study, the LEAD Tool provides estimates derived from the US Census Bureau's 2018 American Community Survey (ACS) Public Use Microdata Samples (PUMS). In specific, LEAD includes estimated household energy cost, energy burden, and housing count according to the following criteria:

- Geographic levels – this study obtained and mapped LEAD at the Census Tract level
- AMI levels – income below 80% AMI was defined as "low-income" in this study
- Building age (construction year of housing unit)
- Heating fuel types
- Building types – this study excluded boat/RV/van and mobile/trailer from single- and multi-family units counts
- Tenure status (homeowner or renter)

A notable limitation of the LEAD data is that it always reports average energy burdens as whole numbers, without a clear indication of how those numbers are rounded. Therefore, we identified Census tracts with a LEAD-reported Average Energy Bruden of seven or more as High Energy Burden, and eleven or more as Severe Energy Burden. It is possible that this method excludes some Census tracts with an actual, un-rounded Average Energy Burden above 6.0 from the High Energy Burden category, or some above 10.0 from the Severe Energy Burden category. However, we chose to err on the side of caution, and avoid inadvertently including Census tracts in which the actual Average Energy Burden is less than 6.0 or 10.0 from those categories.

Census Geography

Given that the LEAD Tool provides estimates based on 2018 Census data, this study obtained 2018 Virginia Census Tracts from the US Census TIGER/Line Geodatabases page. This study also obtained the 2018 ACS Table B01003 which contains tract-level geography names and population estimates.

Geodatabase Creation and Mapping

The LEAD Tool allows users to specify their own criteria and download the respective data sets in CSV (comma-separated values) format. A number of CSV files about household energy cost, energy burden, and housing count were downloaded according to the criteria stated earlier. The CSV files were further prepared in Excel before they were joined to the 2018 Virginia Census Tracts in ArcGIS Pro. The resulting geodatabase contains attributes listed in the table below.

Attribute	Description
GEO_ID	Unique Identifier
County	Jurisdiction Name (County or City)
Tract	Census Tract Number
Pop_2018	Population (2018 ACS 5-year estimate)
Total_HU	Total - Housing Counts (Single- and Multi-Family combined)
Total_AAEC	Total - Average Annual Energy Cost ($)
Total_AEB_pct	Total - Average Energy Burden (% income)
Single_HU	Single-Family - Housing Counts
Single_AAEC	Single-Family - Average Annual Energy Cost ($)
Single_AEB_pct	Single-Family - Average Energy Burden (% income)
Multi_HU	Multi-Family - Housing Counts
Multi_AAEC	Multi-Family - Average Annual Energy Cost ($)
Multi_AEB_pct	Multi-Family - Average Energy Burden (% income)
AMI_below80_AEB	Low-Income (below 80% AMI) - Average Energy Burden (% income)
AMI_below80_HU	Low-Income (below 80% AMI) - Housing Counts (Single- and Multi-Family combined)
AMI_below80_AEB_single	Low-Income (below 80% AMI) - Single-Family Average Energy Burden (% income)
AMI_below80_HU_single	Low-Income (below 80% AMI) - Single-Family Housing Counts
AMI_below80_AEB_multi	Low-Income (below 80% AMI) - Multi-Family Average Energy Burden (% income)
AMI_below80_HU_multi	Low-Income (below 80% AMI) - Multi-Family Housing Counts

Three sets of maps were created to illustrate the spatial distribution and variation of average energy burden, high energy burden (above 6%), and severe energy burden (above 10%) low-income households at the Census Tract level. Virginia Census Tracts were classified into five groups using the Natural Breaks method which optimizes classification by minimizing the within-group difference while maximizing the between-group difference. These maps and their associated attributes are listed below.

<u>Average Energy Burden</u>

- Average Energy Burden of Low-Income (below 80% AMI) Households
  Attribute: AMI_below80_AEB
- Average Energy Burden of Single-Family Low-Income (below 80% AMI) Households
  Attribute: AMI_below80_AEB_single
- Average Energy Burden of Multi-Family Low-Income (below 80% AMI) Households
  Attribute: AMI_below80_AEB_multi

High Energy Burden (above 6%) Housing Units

- Housing Units of High Energy Burden and Low-Income (below 80% AMI)
  Attribute: AMI_below80_HU, where AMI_below80_AEB > 6
- Single-Family Housing Units of High Energy Burden and Low-Income (below 80% AMI)
  Attribute: AMI_below80_HU_single, where AMI_below80_AEB_single > 6
- Multi-Family Housing Units of High Energy Burden and Low-Income (below 80% AMI)
  Attribute: AMI_below80_HU_multi, where AMI_below80_AEB_multi > 6

Severe Energy Burden (above 10%) Housing Units

- Housing Units of Severe Energy Burden and Low-Income (below 80% AMI)
  Attribute: AMI_below80_HU, where AMI_below80_AEB > 10
- Single-Family Housing Units of Severe Energy Burden and Low-Income (below 80% AMI)
  Attribute: AMI_below80_HU_single, where AMI_below80_AEB_single > 10
- Multi-Family Housing Units of Severe Energy Burden and Low-Income (below 80% AMI)
  Attribute: AMI_below80_HU_multi, where AMI_below80_AEB_multi > 10

Appendix B. Census Tracts in Virginia with Extreme Low-Income Energy Burden

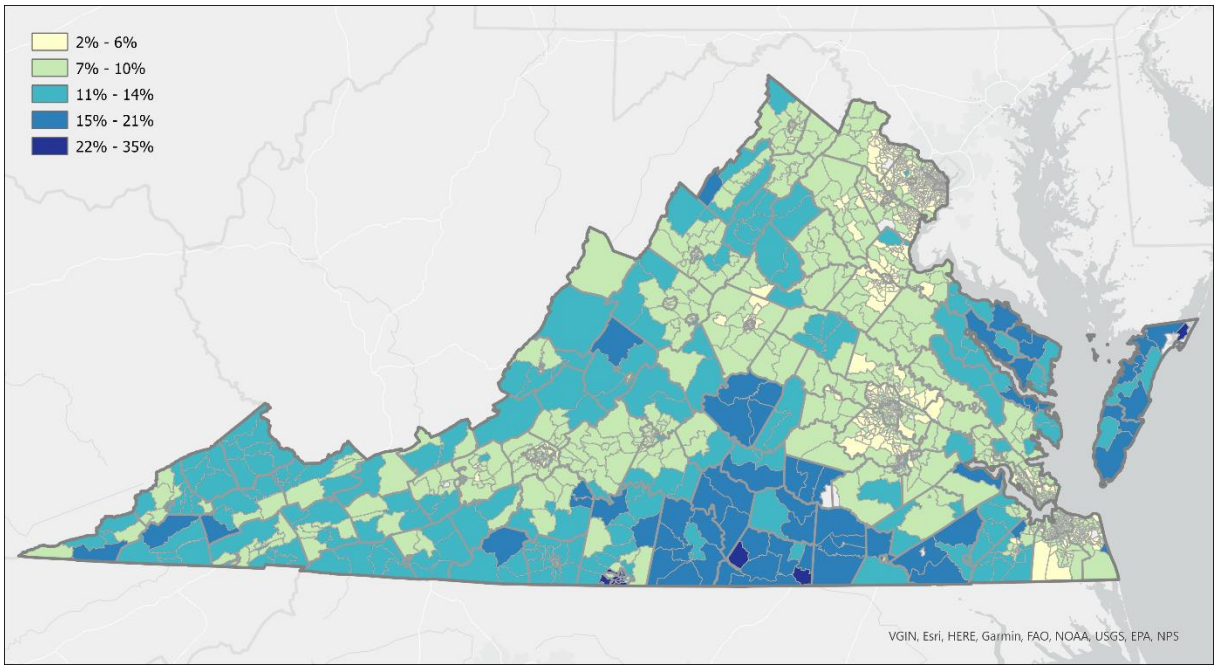
The following table lists all 76 Virginia Census Tracts in which the average energy burden (AEB) for all low-income households (AEB-LI) is 15% or above (i.e., twice the U.S. national average). These tracts are listed in descending order based on their AEB-LI. The table also lists the percent of all households in each tract that are low-income (PCT HU < 80 AMI), the Average Annual Energy Costs (AAEC) for all households in that Census Tract, and the average annual energy burden (AEB) for all households in the Tract.

County	Census Tract	Pop. (2018)	Housing Units	PCT HU < 80 AMI	AAEC	AEB (All Households	AEB (AMI < 80)
Danville city	4	3300	1389	72.1%	$5,117	18	32
Danville city	11	1387	596	58.6%	$5,283	12	29
Danville city	6	1945	919	48.5%	$5,250	11	29
Albemarle County	109.03	3159	98	93.9%	$1,538	20	29
Danville city	10	3944	1548	63.8%	$4,903	12	27
Danville city	3	2840	1461	57.2%	$5,237	15	26
Danville city	8	2676	1214	38.2%	$4,702	8	26
Mecklenburg County	9301.02	2872	1207	17.1%	$5,754	10	25
Accomack County	901	2899	1523	26.3%	$4,941	7	25
Danville city	12	1866	759	33.9%	$4,805	8	24
Pittsylvania County	112	2254	1075	44.1%	$4,693	10	24
Mecklenburg County	9305	1616	706	25.5%	$3,972	6	23
Hampton city	114	2744	250	90.0%	$2,031	10	22
Danville city	9	3323	1567	50.5%	$4,784	10	21
Mecklenburg County	9307	2096	1095	22.6%	$4,496	8	21
Northumberland County	202	2906	1394	29.1%	$4,049	6	20
Mecklenburg County	9306	2819	991	25.7%	$4,002	6	20
Lunenburg County	9303	2357	872	28.4%	$3,835	7	20
Danville city	5	1931	910	65.4%	$3,658	11	20
Nottoway County	2	2809	1169	29.9%	$3,381	6	20
Brunswick County	9301	3195	1445	26.6%	$3,341	6	20
Danville city	7	3346	1340	31.9%	$5,122	6	19
Middlesex County	9512	2720	1134	35.9%	$4,606	7	19
Danville city	2	4100	1846	50.1%	$4,177	9	19
Buckingham County	9301.01	4240	1674	21.2%	$3,399	6	19
Virginia Beach city	454.12	1591	590	21.5%	$5,211	4	18
Shenandoah County	402.01	2362	1015	22.8%	$5,040	6	18
Accomack County	905	2310	1015	39.8%	$3,243	6	18
Danville city	1	5543	2545	35.4%	$4,487	8	17
Franklin County	201.01	5026	2274	20.5%	$3,734	4	17
Brunswick County	9303	5168	2134	26.9%	$3,570	6	17
Halifax County	9303.01	2521	1019	24.5%	$3,544	6	17
Halifax County	9302.01	4560	1802	39.4%	$3,430	7	17
Halifax County	9301	3116	1131	31.2%	$3,402	7	17
Charlotte County	9303	3782	1350	25.4%	$3,370	6	17

County	Census Tract	Pop. (2018)	Housing Units	PCT HU < 80 AMI	AAEC	AEB (All Households	AEB (AMI < 80)
Rockbridge County	9302	4045	1682	44.3%	$3,280	5	17
Mecklenburg County	9303	3487	1104	30.0%	$3,262	5	17
Westmoreland County	101	4729	2079	32.0%	$4,051	5	16
Lancaster County	301	3230	1454	41.9%	$3,900	6	16
Northumberland County	201	3672	1636	34.1%	$3,713	6	16
Accomack County	902	5960	2563	25.8%	$3,702	7	16
Lunenburg County	9301	5602	1726	35.1%	$3,481	7	16
Mecklenburg County	9308	4032	1458	34.2%	$3,461	6	16
Buckingham County	9302.01	5412	1247	28.6%	$3,451	6	16
Middlesex County	9511	2589	1163	42.4%	$3,385	6	16
Mecklenburg County	9301.01	3063	1114	25.0%	$3,356	6	16
Northampton County	9303	4093	1830	38.0%	$3,171	5	16
Charlotte County	9301	5322	2058	37.4%	$3,154	6	16
Accomack County	908	3609	1348	30.1%	$3,141	6	16
Brunswick County	9302.01	2126	742	37.7%	$3,126	7	16
Halifax County	9302.02	2293	970	30.1%	$3,109	6	16
Mecklenburg County	9304	5248	2000	43.0%	$3,098	7	16
Scott County	303	3104	1271	24.7%	$3,069	7	16
Lee County	9504	2616	1050	35.9%	$2,710	7	16
Franklin County	201.02	2691	1193	16.8%	$4,294	4	15
Northumberland County	203	5645	2656	31.9%	$3,910	4	15
Surry County	8601	2779	1233	42.0%	$3,769	6	15
Southampton County	2005	3704	1494	27.4%	$3,651	5	15
Southampton County	2001	4110	1650	28.5%	$3,502	6	15
Prince Edward County	9303	7124	2089	27.3%	$3,486	5	15
Southampton County	2002	2613	1007	31.5%	$3,480	5	15
Suffolk city	753.02	2402	973	28.7%	$3,441	4	15
Middlesex County	9510	3601	1511	34.9%	$3,408	5	15
Pittsylvania County	103	3964	1777	23.9%	$3,298	6	15
Halifax County	9304	3854	1469	24.4%	$3,296	5	15
Buckingham County	9302.02	4425	1689	21.4%	$3,264	5	15
Buckingham County	9301.02	2927	1217	27.9%	$3,256	7	15
Accomack County	903	2527	1021	36.9%	$3,208	5	15
Nottoway County	3	7300	2471	36.0%	$3,198	6	15
Pittsylvania County	107	1603	685	24.5%	$3,163	6	15
Charlotte County	9302	2991	1135	35.3%	$2,977	6	15
Halifax County	9303.02	4231	1974	28.3%	$2,935	5	15
Accomack County	906	3693	1875	35.1%	$2,896	5	15
Northampton County	9301	4386	1833	38.8%	$2,893	5	15
Halifax County	9306	5071	2076	45.5%	$2,882	6	15
Russell County	303	3778	1535	29.8%	$2,584	6	15

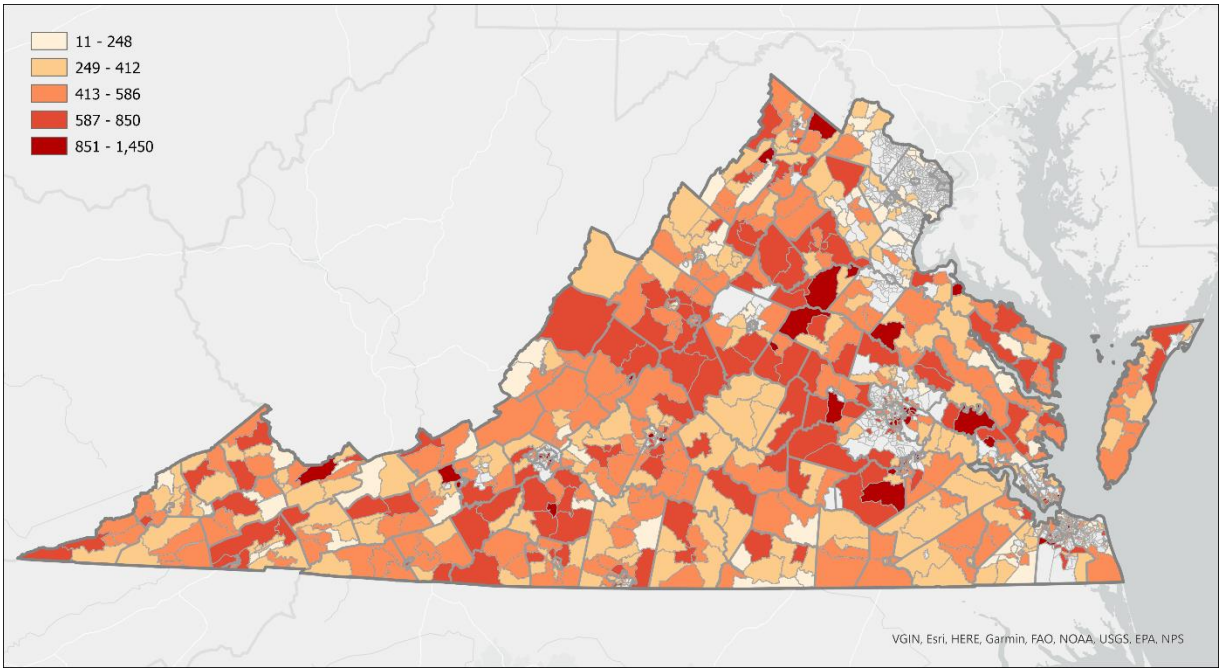
Appendix C. Energy Burden Maps – Single and Multi-Family Homes

Map A-1. Average Energy Burden of Single-Family Low Income (below 80% AMI) Households by Census Tract in 2018



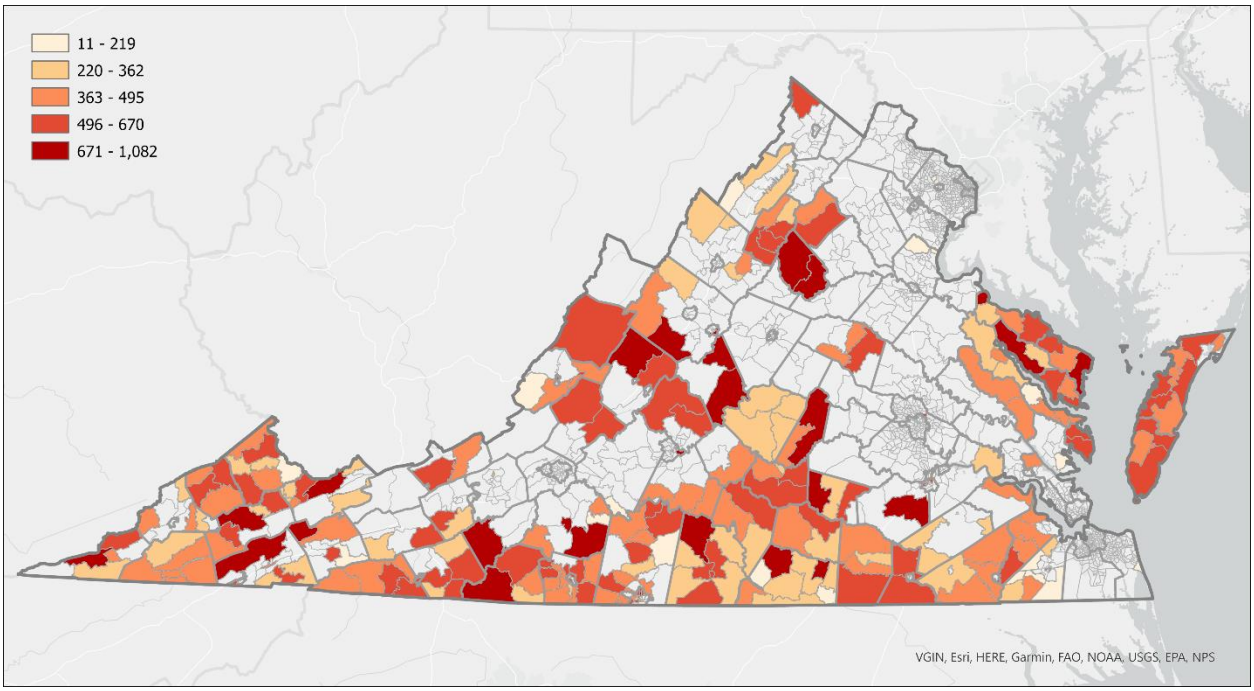
Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

Map A2. Single-Family Housing Units (435,796) of High Energy Burden (above 6%) and Low Income (below 80% AMI) by Census Tract in 2018



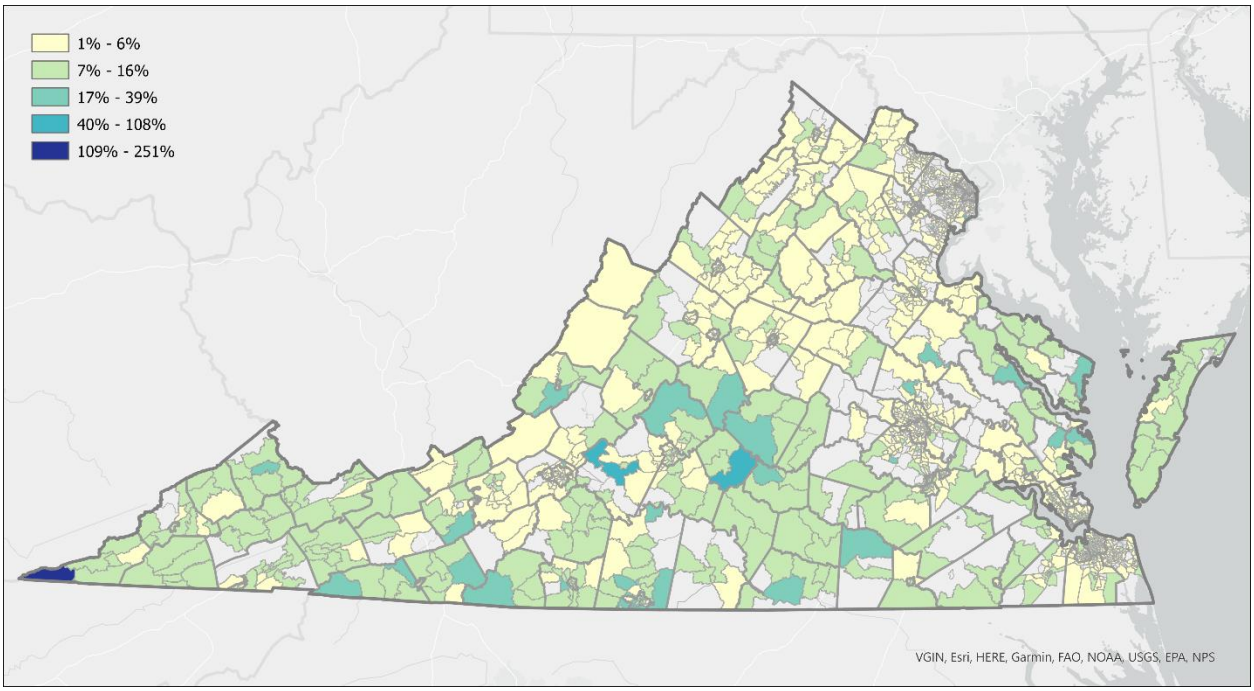
Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

Map A3. Single-Family Housing Units (128,979) of Severe Energy Burden (above 10%) and Low Income (below 80% AMI) by Census Tract in 2018



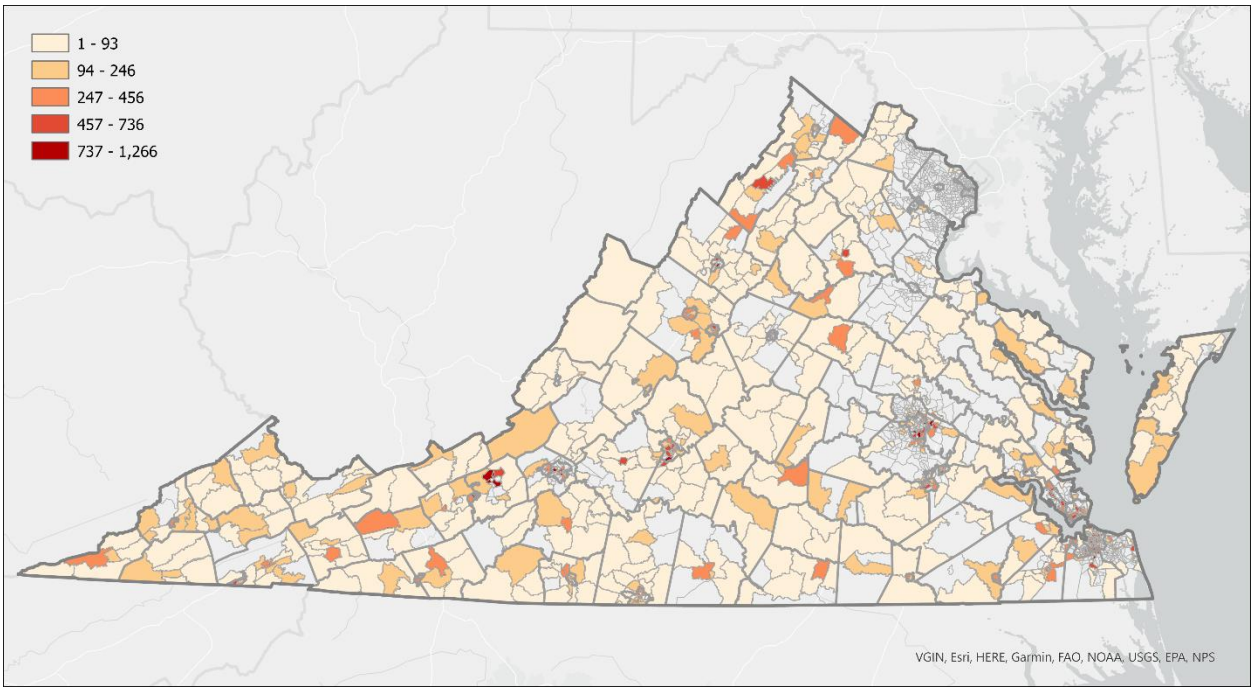
Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

Map A4. Average Energy Burden of Multi-Family Low Income (below 80% AMI) Households by Census Tract in 2018



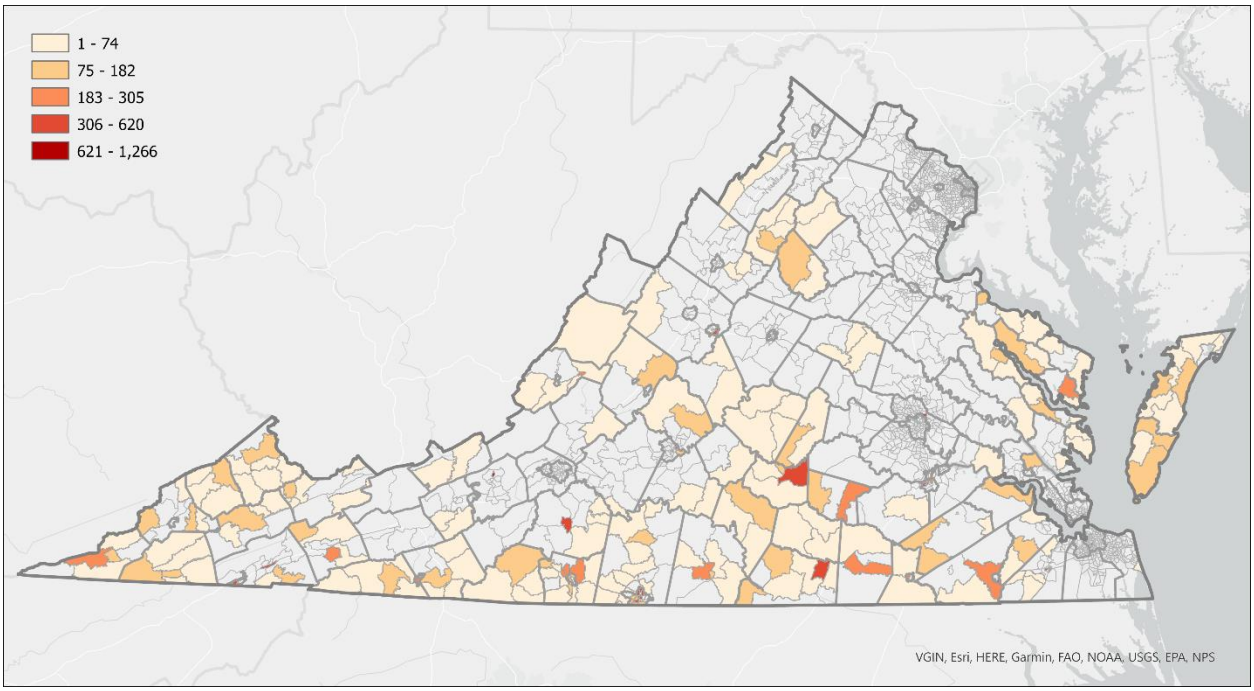
Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

Map A5. Multi-Family Housing Units (143,195) of High Energy Burden (above 6%) and Low Income (below 80% AMI) by Census Tract in 2018



Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

Map A6. Multi-Family Housing Units (25,160) of Severe Energy Burden (above 10%) and Low Income (below 80% AMI) by Census Tract in 2018



Source: Low-Income Energy Affordability Data (LEAD), US Department of Energy

Appendix D. Data Tables for HIEE Program Modeling

Tables A.2 and A.3 below demonstrate the detailed calculations for the total number of low-income housing units, listed in Table 7, that could receive energy efficiency upgrades under our Low and High RGGI / HIEE revenue scenarios, respectively. The Total HIEE Revenue column is equal to half of Virginia's actual RGGI revenue in 2021-2022, and projected revenue for 2023-2030 (Low and High scenarios), per the process outlined in Section 4.2 and summarized in Table 6. The HIEE revenue totals for 2022 include the $11.4 million deduction from that year's HIEE budget and transferred to the Hurley flood relief fund.

As described in Section 4.2.1, we assume an overall HIEE funding distribution of 85% to ASNH-EE projects, 12.75% to WDR-Single-Family projects, and 2.25% to WDR-Multi-Family projects, which is consistent with the actual HIEE funding distributions to-date. The Total HIEE Revenue values, multiplied by those percentages, produce the values listed in the respective "Budget by Project Types" columns.

The average costs per unit for 2021-2022 are based on our calculations of the actual costs per unit for each HIEE project type, based on available DHCD data. For each subsequent year the average costs per unit are increased by 3%. Dividing the Budget by Project Type values by the Average Cost per Unit values produces the "Potential Units Funded" totals for each HIEE project type.

Table A.4. shows our detailed calculations for the reduced energy consumption and customer bill savings that would result from the energy efficiency upgrades calculated for each revenue scenario. The total units match the values found in Tables A.2 and A.3. The Energy Savings per Unit are based on research findings reported by the Virginia Center for Housing Research at Virginia Tech. Customer bill savings are based on Virginia's average electricity rate of $0.12 / kWh in 2021, increased by 2.17% per year in ensuing years, consistent with the statewide trend from 2002-2021.

Table A.2. Housing Model Details – Low Revenue Scenario

Year	Total HIEE Revenue ($Million)	Budget by Project Types			Average Cost per Unit			Potential Units Funded		
		ASNH-EE	WDR-SFH	WDR – MFH	ASNH-EE	WDR-SFH	WDR – MFH	ASNH-EE	WDR-SFH	WDR – MFH
2021	$113.82	$96.75	$14.51	$2.56	$12,190	$13,260	$2,170	7,936	1,094	1,180
2022	$138.00*	$117.30	$17.60	$3.11	$12,190	$13,260	$2,170	9,623	1,327	1,431
2023	$150.88	$119.09	$17.86	$3.15	$12,556	$13,658	$2,235	9,485	1,308	1,410
2024	$152.13	$111.50	$16.72	$2.95	$12,932	$14,068	$2,302	8,622	1,189	1,282
2025	$153.13	$104.21	$15.63	$2.76	$13,320	$14,490	$2,371	7,824	1,079	1,163
2026	$153.85	$97.23	$14.58	$2.57	$13,720	$14,924	$2,442	7,086	977	1,054
2027	$191.80	$112.55	$16.88	$2.98	$14,132	$15,372	$2,516	7,964	1,098	1,184
2028	$193.74	$105.57	$15.84	$2.79	$14,555	$15,833	$2,591	7,253	1,000	1,078
2029	$195.40	$98.86	$14.83	$2.62	$14,992	$16,308	$2,669	6,594	909	981
2030	$196.73	$92.43	$13.86	$2.45	$15,442	$16,797	$2,749	5,986	825	890
Total	**$1,639**	**$1,055**	**$158.32**	**$27.94**	**NA**	**NA**	**NA**	**78,373**	**10,806**	**11,653**

Table A.3. Housing Model Details – High Revenue Scenario

Year	Total HIEE Revenue ($Million)	Budget by Project Types			Average Cost per Unit			Potential Units Funded		
		ASNH-EE	WDR-SFH	WDR – MFH	ASNH-EE	WDR-SFH	WDR – MFH	ASNH-EE	WDR-SFH	WDR – MFH
2021	$113.82	$96.75	$14.51	$2.56	$12,190	$13,260	$2,170	7,936	1,094	1,180
2022	$138.00*	$117.30	$17.60	$3.11	$12,190	$13,260	$2,170	9,623	1,327	1,431
2023	$150.88	$128.25	$19.24	$3.39	$12,556	$13,658	$2,235	10,214	1,408	1,519
2024	$152.13	$129.31	$19.40	$3.42	$12,932	$14,068	$2,302	9,999	1,379	1,487
2025	$153.13	$130.16	$19.52	$3.45	$13,320	$14,490	$2,371	9,772	1,347	1,453
2026	$153.85	$130.77	$19.62	$3.46	$13,720	$14,924	$2,442	9,532	1,314	1,417
2027	$191.80	$163.03	$24.45	$4.32	$14,132	$15,372	$2,516	11,536	1,591	1,715
2028	$193.74	$164.68	$24.70	$4.36	$14,555	$15,833	$2,591	11,314	1,560	1,682
2029	$195.40	$166.09	$24.91	$4.40	$14,992	$16,308	$2,669	11,078	1,528	1,647
2030	$196.73	$167.22	$25.08	$4.43	$15,442	$16,797	$2,749	10,829	1,493	1,610
Total	**$1,639**	**$1,394**	**$209.03**	**$36.89**	**NA**	**NA**	**NA**	**101,833**	**14,041**	**15,141**

Table A.4. Energy Savings Model Details

Low Scenario	Total Units	Energy Savings / Unit (MMBTU)	Total Energy Savings (MMBTU)	Total Energy Savings (MWH)	Total Bill Savings ($Millions)	Energy Savings per Unit (kWh)	Bill Savings per Unit ($)
ASNH-EE	78,373	13.97	1,094,485	320,775	$48.12	4,093	$613.94
WDR - SFH	10,806	37.10	400,903	117,498	$17.62	10,873	$1,631.01
WDR - MFH	11,653	4.80	55,934	16,393	$2.46	1,407	$211.02
Totals	**100,832**	**NA**	**1,551,322**	**454,666**	**$68.20**	**4,509**	**$676.37**
High Scenario	**Total Units**	**Energy Savings / Unit (MMBTU)**	**Total Energy Savings (MMBTU)**	**Total Energy Savings (MWH)**	**Total Bill Savings ($Millions)**	**Energy Savings / Unit (kWh)**	**Bill Savings / Unit ($)**
ASNH-EE	101,833	13.97	1,422,105	416,795	$62.52	4,093	$613.94
WDR - SFH	14,041	37.10	520,921	152,673	$22.90	10,873	$1,631.01
WDR - MFH	15,141	4.80	72,677	21,300	$3.20	1,407	$211.02
Totals	**131,015**	**NA**	**2,015,703**	**590,769**	**$88.62**	**4,509**	**$676.37**

Attachment 60

GOVERNOR NORTHAM ANNOUNCES OVER $21 MILLION IN AFFORDABLE AND SPECIAL NEEDS HOUSING LOANS

July 8, 2021

FUNDING WILL SUPPORT NEW CONSTRUCTION AND REHABILITATION OF 1,266 AFFORDABLE AND PERMANENT SUPPORTIVE HOUSING UNITS

Governor Ralph Northam today announced more than $21 million in Affordable and Special Needs Housing loans for 24 projects across Virginia, creating or preserving 1,266 affordable housing units for low-income and extremely low-income households. The funding will improve access to affordable housing, reduce homelessness, provide permanent supportive housing options for individuals with intellectual and developmental disabilities, and complete energy efficiency updates in affordable housing units.

“Quality, affordable housing is the key to advancing equity, opportunity, and economic prosperity in every corner of our Commonwealth,” said Governor Northam. “The Affordable and Special Needs Housing program is an important resource for increasing access to safe and sustainable housing for low-income families, individuals with disabilities, and Virginians experiencing homelessness.”

The Virginia Department of Housing and Community Development (DHCD) administers Affordable and Special Needs Housing (ASNH) loans, which combine state and federal resources to provide a simplified and comprehensive application process. Funding comes from four main sources: the federal HOME Investment Partnerships Program, the federal National Housing Trust Fund (NHTF), the Virginia Housing Trust Fund (VHTF), and Housing Innovations in Energy Efficiency (HIEE) funds. In this round, DHCD awarded approximately $1.6 million in HOME funding, $1.1 million in NHTF funding, $12.6 million in VHTF funding, and $6.2 million in HIEE funding.

Governor Northam and the General Assembly invested an historic $70.7 million in the Virginia Housing Trust Fund this fiscal year, which provides financing for housing construction projects that create or preserve affordable housing units, reduce the cost of affordable housing, and increase homeownership. VHTF is a key source of

financing to support moderate- and-low-income families in addition to providing homeless reduction grants for rapid re-housing and longer-term housing solutions for individuals experiencing chronic homelessness.

“Providing housing stability and supporting programs to make homelessness rare, brief, and nonrecurring is more important now than ever as we turn the corner from this pandemic,” said Secretary of Commerce and Trade Brian Ball. “These loans will fill gaps in financing to make safe and affordable housing for our most vulnerable populations possible, which in turn strengthens our communities, our economy, and improves the lives of many Virginians across the Commonwealth.”

ASNH loans are awarded through a competitive process. Forty-one applications requesting over $45 million were received for this round of funding. Proposals were reviewed, evaluated, and scored with proposals ranked and award offers recommended to the highest-ranking proposals based on funding availability. The funded projects will leverage over $307 million in additional federal, state, local, and private lending resources.

2021 Spring Affordable and Special Needs Housing Awardees:

Friendship Court Phase I | Piedmont Housing Alliance
$1,500,000 (HIEE)
$200,000 (NHTF)
$200,000 (VHTF)
City of Charlottesville

Friendship Court Phase I is the new construction of 106 units in the phased redevelopment of the existing Friendship Court site in Charlottesville. This new construction will occur in greenspace so there will be no displacement during construction, and it will consist of both stacked townhomes and a multi-family building. Friendship Court was previously awarded funds through a competitive ASNH application, and this additional application supports the implementation of Zero Energy Ready Homes and Passive House certification standards, as well as permanent supportive housing units, which will provide select tenants with additional wraparound services on site.

Premier Circle Permanent Supportive Housing | Virginia Supportive Housing
$900,000 (VHTF)
$560,000 (HIEE)
Albemarle County

Premier Circle Permanent Supportive Housing is the construction of 80 units for formerly homeless and low-income adults from the Charlottesville region. Each studio unit will be approximately 350 square feet and contain a kitchen and full bathroom, and resident amenities include phone and computer rooms, laundry facilities, a fitness area, and free Wi-Fi. The building will have staff offices for on-site supportive services and property management, a front desk staffed 16 hours per day, and a night monitor unit. The entire building will meet Universal Design standards and EarthCraft Gold certification.

Southwood Affordable Homeownership | Greater Charlottesville Habitat for Humanity

$1,400,000 (VHTF)

Albemarle County

Southwood Affordable Homeownership is the construction of 16 single-family condo units, five single-family attached townhome units, four single-family duplex units, and one single-family detached unit. The 26 new homes will be constructed in the existing Southwood mobile home park and serve families relocating from substandard mobile homes in the park. The homes will serve residents at or below 60 percent of the Area Median Income (AMI).

Braddock Four Senior | Arlington Partnership for Affordable Housing

$700,000 (VHTF)

$655,000 (HIEE)

Fairfax County

Braddock Four Senior is the new construction of a four-story building housing 44 senior housing units. All residents will have in-unit washers and dryers, free Wi-Fi, and access to a business center, fitness room, and wellness suite. The building will have on-site property management and leasing, bilingual resident services, and active outreach to residents at risk of eviction to enable immediate and long-term stability. All units are accessible via Universal Design and are available to seniors with incomes less than 60 percent of the AMI. Braddock Four will be co-located with another senior housing community, Braddock Nine Senior.

Braddock Nine Senior | Arlington Partnership for Affordable Housing

$700,000 (VHTF)

$555,000 (HIEE)

Fairfax County

Braddock Nine Senior is the new construction of a four-story building housing 36 senior housing units. All residents will have in-unit washers and dryers, free Wi-Fi, and access to a business center, fitness room, and wellness center. The building will have on-site property management and leasing, bilingual resident services, and active outreach to residents at risk of eviction to enable immediate and long-term stability. All units are accessible via Universal Design. Four units will be available to very-low income seniors with incomes less than 30 percent of the AMI, 14 will be available to those with incomes less than 50 percent of the AMI, and the remaining will be reserved for seniors with incomes less than 60 percent of the AMI.

Bickerstaff Crossing | Surber Development and Consulting, LLC

$637,052 (VHTF)

$590,835 (HIEE)

Henrico County

Bickerstaff Crossing is the new construction of one building containing 60 two- and three-bedroom rental units serving individuals or families earning less than 30, 50, and 60 percent of the AMI. All units will be built to meet Universal Design standards and with Energy Star appliances, and five units will be fully accessible and marketed

to individuals with disabilities. The building will be EarthCraft certified, contain community space, an on-site leasing office, and shared laundry, and each unit will have washer and dryer connections. Through its established adult programs, nonprofit Soar365 will provide support services and training and education programs to residents. The building will be served by a Tenants Council.

Powhatan Terrace Townhomes | Housing Partnership, Inc.
$700,000 (VHTF)
$500,000 (NHTF)
James City County

Powhatan Terrace Townhomes is the new construction of 36 two- and three-bedroom rental townhomes spread across six two-story buildings, one of which includes a community room with free Wi-Fi for residents. The site also features a playground, greenspace, and a walking path. Five units will meet Universal Design requirements and all buildings will meet Energy Star standards. Colonial Behavioral Health will provide permanent supportive housing services to residents with intellectual or developmental disabilities or serious mental illness. Housing and financial counseling services will be available to all residents. The development will serve individuals and families with incomes less than 60 percent of the AMI.

Poplar Creek Homes 2 | Southside Outreach Group
$900,000 (HOME)
$270,000 (HIEE)
Town of South Boston

Poplar Creek Homes 2 is the new construction of 16 duplexes that will have 32 units of rental housing in a new subdivision. These two-story units will be comprised of one-, two-, and three-bedroom homes on a 1/5 acre lot with their own driveways and will meet EarthCraft Gold standards and the Department of Energy's Zero Energy Ready Homes program.

South First Phase One | Charlottesville Redevelopment and Housing Authority
$434,000 (HIEE)
$250,000 (NHTF)
$250,000 (VHTF)
City of Charlottesville

South First Street Phase One is the new construction of 62 one-, two-, and three-bedroom apartment units across three garden-style apartment buildings. The development includes substantial indoor community resource space programmed and designed by residents. Outdoor amenity spaces and access to trails and recreational space along Pollack's Branch will be available for residents and the surrounding community. The buildings will be EarthCraft Gold certified, meet passive-house standards, and support a photovoltaic array.

Newport Gardens | The Hanson Company
$850,000 (VHTF)
City of Norfolk

Newport Gardens is the new construction of 50 apartments in the Park Place neighborhood. The single building of one- and two-bedroom apartments will be EnergyStar-certified and include a gym, community space, and laundry facilities. Individual units will have granite countertops, hardwood floors, and ceramic tile as well as full size appliances and washer and dryer connections.

Crescent Halls | Charlottesville Redevelopment and Housing Authority

$735,000 (HIEE)

$100,000 (VHTF)

City of Charlottesville

Crescent Halls is the substantial rehabilitation of an eight-story building comprised of 105 apartment units for lower-income seniors in Charlottesville. This renovation includes new unit layouts, finishes, plumbing fixtures and appliances, building-wide mechanical systems and windows, elevator modernization, and roofing that will support a photovoltaic array. The renovated units will continue to serve seniors and disabled residents, providing better access through the retrofitting of 11 units that will include roll-in showers, grab bars, roll under sinks, and front controls on ranges. Renovations will also address necessary repairs to asphalt paving and create accessible parking and building routes.

Holly Court | Community Housing Partners

$700,000 (VHTF)

Lancaster County

Holly Court is the substantial rehabilitation of 40 one-bedroom senior apartments across three one-story buildings in Kilmarnock. All units will meet Universal Design standards and five units will have additional design for accessibility under Section 504. Two units will be designed to serve residents with hearing or visual impairments. Improvements include a new roof, gutters, and downspouts, replacement of cabinets, countertops, appliances, lighting and bath fixtures, installation of low-flow faucets, shower heads, and toilets as well as the replacement of the existing HVAC and water heater systems. The building will be EarthCraft Gold certified.

Goose Creek Crossing | Hill Tide Housing Investments, LLC

$700,000 (VHTF)

Augusta County

Goose Creek Crossing is the new construction of 116 units of two- and three-bedroom rental apartments across a 6.6 acre site in Staunton. The site will include a community building with an exercise area, computer room, laundry facilities, and management and maintenance offices. A playground and picnic shelter for residents will be on site and Commonwealth Catholic Charities will provide resident services such as homeownership and financial counseling and employment services. All buildings in the development will be EarthCraft Gold certified for efficiency.

Oak Terrace | Hill Tide Housing Investments, LLC

$700,000 (VHTF)

City of Suffolk

Oak Terrace is the new construction of 120 two- and three-bedroom apartments across five three-story buildings in Suffolk. The construction will be built to EarthCraft standards and include a playground and picnic shelter, a community building with laundry facilities, a computer room, and exercise area. Forty units will meet Universal Design requirements, and 12 units will be ADA-compliant with three units equipped to serve individuals with sensory impairments. Commonwealth Catholic Charities will provide financial coaching and education and employment services to tenants.

Aaron Mills Apartments | Landmark Asset Services, Inc.

$700,000 (VHTF)

City of Martinsville

Aaron Mills Apartments is the new construction of 52 one- and two-bedroom senior apartments in a single building. Every unit and all common areas will meet Universal Design standards, and the building will be EarthCraft certified. The site includes a community room with free Wi-Fi, a business center with computers and printer, an exercise room, on-site laundry facilities, a covered picnic shelter with tables and a grill, and planting gardens. Units will be equipped with LED light fixtures, energy efficient appliances and mechanical systems, front-control ranges, and in-unit washer and dryer hookups.

Brook Villas | Mark-Dana Corporation

$175,000 (HIEE)

$175,000 (HOME)

$175,000 (NHTF)

$175,000 (VHTF)

Henrico County

Brook Villas is the new construction of 84 units of one-, two-, and three-bedroom low-rise apartments in Henrico County. The apartments will be built to EarthCraft Gold standards and all 28 first floor units will meet Universal Design requirements. All apartments will be built to allow high speed internet connectivity and will have washer and dryer connections. Community laundry machines will be provided and there will be on-site leasing, a community room and fitness facilities, and financial counseling and job search services available to tenants.

Magnolia Place Apartments | TM Associates Management, Inc.

$700,000 (VHTF)

Nottoway County

Magnolia Place Apartments is the substantial rehabilitation of 56 one-bedroom senior garden-style apartments. All units will be renovated to meet Universal Design standards and will have a dishwasher. Renovations include structural work, installation of free Wi-Fi in the community building, and apartments will have WaterSense fixtures and EnergyStar appliances installed to complement the new mechanical systems, cabinets, vanities, countertops, fixtures, and appliances. The buildings will be EarthCraft Gold certified. This development will continue to serve seniors with incomes less than 50 percent of the AMI.

Dupuy Road Project | Maggie Walker Community Land Trust

$700,000 (VHTF)

Chesterfield County

Dupuy Road is the new construction of 10 three-bedroom, single family affordable homes on the site of the former Ettrick Elementary School Annex. These homes will be built in partnership with project:Homes to meet EarthCraft standards. The site will include the installation of a road, utilities, walking paths, and greenspace.

Quarry Station | Wesley Housing

$700,000 (VHTF)

City of Manassas

Quarry Station is the substantial rehabilitation of 79 units of existing one- and two-bedroom senior apartments. This renovation allows for individuals with incomes less than 40 percent of the AMI to qualify for further reduction in rent while also increasing livability of the building. The renovation scope will include improvements to HVAC systems, installation of new water-saving fixtures, improvements to the accessibility and durability of common area spaces, the addition of a single one-bedroom unit, and upgrades to the parking lot and outdoor areas.

Lambert Landing II | Woda Cooper Companies, Inc.

$700,000 (VHTF)

Chesterfield County

Lambert Landing II is the new construction of 48 family apartment units comprised of 40 two-bedroom apartments and eight three-bedroom units in a single four-story garden apartment building. The apartments will have an open layout, ample storage and closets, and unit amenities including central air conditioning, dishwashers, garbage disposals, and full-size kitchen appliances. The building will be EnergyStar certified.

Cool Lane Apartments | Virginia Supportive Housing

$602,000 (HIEE)

Henrico County

Cool Lane Apartments is the adaptive re-use of a vacant building in Henrico County. Virginia Supportive Housing will renovate the former assisted living facility into permanent supportive housing for homeless and low-income individuals. The existing structure will be redesigned and adapted to create 86 units for homeless and low-income individuals earning less than 50 percent of the AMI from Henrico County and the City of Richmond.

Canterbury Subdivision Phase II | Greater Fredericksburg Habitat for Humanity

$500,000 (HOME)

City of Fredericksburg

Canterbury Subdivision Phase II is the new construction of five single-family homes in the Mayfield neighborhood in Fredericksburg. To accommodate five new affordable homes in the existing market-rate community, the neighborhood streets, including power lines, the sewer system, and the road will be extended. Homes will be built

to EnergyStar standards, lowering the ongoing costs to homeowners, and will be sold to families making less than 60 percent of the AMI. Homebuyers will be provided with pre- and post-closing homeownership and financial counseling and will perform ‘sweat equity’ to contribute to the construction of their home.

Oak Street Aging in Place | Community Havens, Inc.

$400,000 (VHTF)

City of Manassas

Oak Street Aging in Place is the new construction of a single-level, fully ADA-accessible home with six bedrooms and adjoining baths. The site already serves five individuals in a two-story home that is not ADA-compliant. This new construction will serve individuals with intellectual or developmental disabilities who have escalating needs as they age. Residents will be able to participate in activities such as gardening and meal preparation. Once demolition of the older structure is complete, residents will have ample space for yard games and activities.

Fairview Town Homes Energy Efficiency | Helping Overcome Poverty’s Existence, Inc.

$84,000 (HIEE)

Town of Wytheville

The Fairview Town Homes Energy Efficiency project will create 12 two-bedroom units with four units reserved for permanent supportive housing. These townhomes will be part of a larger 51-unit redevelopment effort at the former Woodlawn School. The permanent supportive housing services will be provided through a memorandum of understanding with Mount Rogers Community Services.

EQUAL HOUSING OPPORTUNITY

Attachment 61

GOVERNOR NORTHAM ANNOUNCES OVER $60 MILLION IN AFFORDABLE AND SPECIAL NEEDS HOUSING LOANS

January 13, 2022

FUNDING WILL SUPPORT NEW CONSTRUCTION AND REHABILITATION OF OVER 2,500 AFFORDABLE AND SPECIAL NEEDS HOUSING UNITS

Governor Ralph Northam today announced more than $60 million in Affordable and Special Needs Housing loans for 42 projects across the Commonwealth, creating or preserving 2,552 affordable housing units for low-income and extremely low-income households. The funding will improve access to energy efficient affordable housing, reduce homelessness, provide permanent supportive housing options for individuals with intellectual and developmental disabilities, and complete energy efficiency updates in affordable housing units.

“Quality, affordable housing is essential to building vibrant communities and ensuring every Virginian has the opportunity to thrive,” said Governor Northam. “We must keep investing in the Commonwealth’s stock of affordable housing, and the Affordable and Special Needs Housing programs will continue to be a vitally important resource for vulnerable Virginians. In addition to its tremendous work supporting affordable housing, community development, and other priorities, DHCD has led our programs to keep people in their homes and support small businesses during the pandemic. I want to thank DHCD Director Erik Johnson for his superb leadership of the agency, especially during the past 22 months. He has led an outstanding and creative team in finding innovative ways to help people during a challenging time.”

The Virginia Department of Housing and Community Development administers Affordable and Special Needs Housing loans, which combine state and federal resources to provide a simplified and comprehensive application process. Funding comes from four main sources: the federal HOME Investment Partnerships Program, the National Housing Trust Fund, the Virginia Housing Trust Fund, and Housing Innovations in Energy Efficiency funds.

Governor Northam and the General Assembly invested a historic $55 million in the Virginia Housing Trust Fund this fiscal year. VHTF provides financing for housing construction projects that create or preserve affordable housing units, reduce the cost of affordable housing and increase homeownership. This funding is a key source of

financing for these affordable housing initiatives to support moderate-and-low-income families, as well as supporting homeless reduction grants to provide rapid re-housing and longer-term housing solutions for individuals experiencing chronic homelessness.

“Housing stability is more important now than it has ever been as we turn the corner on this pandemic,” **said Secretary of Commerce and Trade Brian Ball.** “These projects will help address the affordable housing needs of the Commonwealth, protect our most vulnerable, strengthen our communities, and support our economy.”

Affordable and Special Needs Housing loans are awarded through a competitive process. Fifty-five applications requesting more than $79 million were received for this round of funding. Proposals were reviewed, evaluated, and scored with proposals ranked and award offers recommended to the highest-ranking proposals based on funding availability. The funded projects will leverage over $651 million in additional federal, state, local and private lending resources.

2021 Fall Affordable and Special Needs Housing Awardees:

ASPIRE | TRG Community Development LLC

$900,000 (VHTF)

$900,000 (NHTF)

$1,764,819 (HIEE)

City of Norfolk

The ASPIRE project consists of demolition and new construction of 85 apartment units in downtown Norfolk to serve families with area median incomes (AMI) between 40% and 80%. The project will accept project-based vouchers for 21 units and will have six permanent supportive housing units.

Southwood Apartments A | Piedmont Housing Alliance

$1,600,000 (HIEE)

$900,000 (NHTF)

$900,000 (VHTF)

Albemarle County

Southwood Apartments A will be a new construction of 70 rental units in Albemarle County. These one-, two- and three- bedroom units will be available for households earning between 30% and 60% AMI. Eight units will have project-based vouchers and six units will be designated for permanent supportive housing. Piedmont Housing is working with a partner to include an onsite Head Start program for residents.

Choice Neighborhood III-R| Newport News Redevelopment and Housing Authority

$700,000 (VHTF)

$700,000 (NHTF)

$2,000,000 (HIEE)

City of Newport News

Choice Neighborhood III-R is a new construction rental project consisting of four buildings for a total of 71 units located in Newport News.

Choice Neighborhood IV-R | Newport News Redevelopment and Housing Authority

$700,000 (VHTF)

$700,000 (NHTF)

$2,000,000 (HIEE)

City of Newport News

Choice Neighborhood IV-R is a new construction rental development with 84 apartments located in Newport News.

Arna Marbella | Arlington Partnership for Affordable Housing

$700,000 (VHTF)

$2,000,000 (HIEE)

Arlington County

Arna Marbella is the renovation of 163 rental units between two properties, Marbella Apartments and Arna Valley View, in Arlington County. The project will include onsite bilingual resident services and free Wi-Fi in each unit.

Premier Circle | Virginia Supportive Housing

$900,000 (HOME)

$900,000 (NHTF)

$714,909 (HIEE)

Albemarle County

Premier Circle is the new construction of 80 units of permanent supportive housing for formerly homeless and low-income adults from the Charlottesville region. Each studio unit will be approximately 350 square feet and contain a kitchen and full bathroom. Resident amenities include phone, computer rooms, a fitness room, laundry facilities and free Wi-Fi. The building will contain staff offices for on-site supportive services and property management, a front desk staffed 16 hours per day and a night-monitor unit.

Middlebrook Trace | Taft-Mills Group

$900,000 (VHTF)

$899,530 (NHTF)

$697,470 (HIEE)

City of Staunton

Middlebrook Trace is the new construction of 82 rental units in Staunton. Eight units will be reserved for permanent supportive housing, and 15 units will accept project-based vouchers. The project will include two- and three-bedroom units. The project will include services to tenants with intellectual and/or developmental disabilities.

CRHA South First Phase Two | Charlottesville Redevelopment and Housing Authority

$400,000 (NHTF)

$2,000,000 (HIEE)

City of Charlottesville

South First Phase Two is a new construction project of 113 rental units in Charlottesville. The project includes one-, two-, three- four-, and five-bedroom apartments across 21 buildings. Fifty-eight of the units will have either a Section 8 or Section 9 subsidy. The project will include a program, in partnership with the Charlottesville Office of Economic Opportunity and Piedmont Virginia Community College, to provide job training. The development also includes substantial indoor community resource space, outdoor amenity spaces, access to trails and recreational space along Pollack's Branch.

Arbors at Birchwood | Marlyn Development Corporation

$100,000 (VHTF)

$2,000,000 (HIEE)

City of Virginia Beach

Arbors at Birchwood is a new construction rental unit development for elderly persons 62 and older on 4.92 acres in Virginia Beach. This project will consist of 150 units designed to meet accessibility needs of residents.

Fairfax Hall | South River Development Corporation

$350,000 (VHTF)

$350,000 (NHTF)

$1,300,000 (HIEE)

City of Waynesboro

Fairfax Hall is an existing project serving primarily senior households in an historic structure in the former Brandon Hotel. This project proposes to retrofit the existing 54 apartments to meet physical accessibility requirements and promote universal access. This project aims to improve energy and operating efficiency by replacing outmoded systems, adding insulation and minimizing water waste. The project has 12 project-based vouchers through Waynesboro Redevelopment and Housing Authority.

Southwood Apartments B | Piedmont Housing Alliance

$900,000 (VHTF)

$1,075,000 (HIEE)

Albemarle County

Southwood Apartments B is a new construction of 51 rental units in Albemarle County. All units will be available for households at or below 60% AMI, with four designated permanent supportive housing units. Piedmont Housing is working with a partner to include an onsite Head Start program for residents.

Watermark Gardens | Surber Development and Consulting LLC

$600,925 (VHTF)

$600,925 (NHTF)

$638,150 (HIEE)

Chesterfield County

Watermark Gardens is the new construction of 80 rental units in Chesterfield. The project will provide services to tenants with intellectual and/or developmental disabilities and the project will accept project-based vouchers.

Horner | Better Housing Coalition

$900,000 (VHTF)

$900,000 (HOME)

Chesterfield County

Horner is the new construction of a 49-unit apartment building in Chesterfield County, comprised of one-, two- and three-bedroom apartments serving families with incomes up to 60% AMI. This development is designed to be pedestrian friendly with well-lit sidewalks, a walking trail, and both active and passive recreation sites. Residents will have access to a fitness room and a community room, which will be programmed with financial literacy classes.

The Villas on Main | Cumberland Plateau Redevelopment and Housing Authority

$450,000 (HOME)

$450,000 (VHTF)

$450,000 (NHTF)

$347, 550 (HIEE)

Russell County

The Villas on Main is a new construction independent residential facility project consisting of 21 units across 10 buildings located in Lebanon. All 21 units will meet Universal Design Standard and include patios and front gardens for the residents. The Villas on Main will serve low-income seniors and disabled persons. The Villas on Main will partner with local service providers to bring supportive services and partner with local agencies to provide transportation for residents.

Townhomes at Liberty Place | Cantebury Enterprises

$700,000 (VHTF)

$900,000 (HOME)

City of Richmond

The Townhomes at Liberty Place are the new construction of 39 rental townhomes in Richmond. The townhomes will consist of a mix of one-, two- and three-bedroom units and for families with incomes between 40-60% AMI. All units will meet Universal Design standards.

Colbrook | Better Housing Coalition

$700,000 (VHTF)

$700,000 (HOME)

Chesterfield County

Colbrook is the adaptive reuse of the historic Colbrook Motel to provide 47 affordable apartments in Chesterfield County. There will be a mix of one-, two- and three-bedroom units. Five units will be set aside for Chesterfield Community Service Board (CSB) clients who will receive rental assistance through the CSB. This project will include a standalone building to provide community space and a museum to honor the motel's previous appearance in the “Green Book,” a travel guide for African Americans during segregation.

Brinshore Block 17 | Brinshore Development, LLC

$700,000 (VHTF)

$700,000 (NHTF)

City of Norfolk

Block 17 Apartments is part of a HUD Choice Neighborhood Initiative and will consist of 68 newly constructed rental units in Norfolk. These units will be a mix of market-rate units and units dedicated for families earning between 30-60% AMI. The units will come with free Wi-Fi and residents will have access to Crestar Health, a nearby Mental Health Clinic, at no cost.

Brinshore Block 18 | Brinshore Development, LLC

$700,000 (VHTF)

$700,000 (NHTF)

City of Norfolk

Block 18 Apartments is part of a HUD Choice Neighborhood Initiative and will consist of 72 newly constructed rental units in Norfolk. These units will be a mix of market rate units and units dedicated for families earning between 30%-60% AMI. Block 18 Apartment residents will have access to Crestar Health, a nearby Mental Health Clinic, at no cost.

Spring Creek, Coleman and Cleveland | Greater Charlottesville Habitat for Humanity

$700,000 (HOME)

$700,000 (VHTF)

Louisa County and City of Charlottesville

Spring Creek, Coleman and Cleveland is a new construction home-buyer project consisting of eight units among three sites. Spring Creek is located in Louisa County, and Coleman Court/Cleveland Avenue is located in the city of Charlottesville. Spring Creek consists of four single-family, four-bedroom homes sitting on .25 acre lots. Coleman Court and Cleveland will consist of two duplex units located within established neighborhoods in Charlottesville. All eight homebuyer units will incorporate Universal Design concepts.

Bellwood Crossing | Hill Tide Investments

$700,000 (VHTF)

$700,000 (NHTF)

Chesterfield County

Bellwood Crossing is a new construction rental property, and this development will consist of 102 units with one- and two-bedroom options. Of the total units, 15 will be allocated for veterans, and up to 10 units will be available for lease through the Chesterfield County Community Services Board. All units will prioritize persons on the public housing waiting list and/or Section 8 of the Richmond Redevelopment and Housing Authority.

Ashlake Trails | Mark-Dana Corporation

$700,000 (VHTF)

$700,000 (HIEE)

Chesterfield County

Ashlake Trails is a low-rise new construction rental development for seniors (55+) comprised of 67 units. The project will consist of 36 one-bedroom units and 31 two-bedroom units. Each unit will be provide free individual Wi-Fi access.

Saint Elizabeth Apartments | Commonwealth Catholic Charities

$800,000 (VHTF)

$500,000 (NHTF)

City of Richmond

Saint Elizabeth Apartments is the new construction of 56 apartments comprised of studios, one-, two-, and three-bedroom units across15 buildings. The apartments would serve families with incomes between 30% and 60% AMI, and would have a community building, playground, and on-site rental office. Six units will be reserved for individuals living with HIV/AIDS that receive HOPWA tenant-based vouchers as well as financial counseling and case management.

Winchester Forest 4 | Better Housing Coalition

$350,000 (VHTF)

$915,000 (HIEE)

Chesterfield County

Winchester Forest 4 is the new construction of 88 one-, two- and three-bedroom rental apartments in North Chesterfield County. Winchester Forest 4 is an expansion of Winchester Greens and Market Square. Site-based services will be provided to improve residents' academic, health and economic outcomes.

Grande Oak III | Surber Development

$375,062 (VHTF)

$375,062 (NHTF)

$499,875 (HIEE)

City of Williamsburg and York County

Grande Oak III is the new construction of 49 rental units in York County. The project has two-bedroom apartments, all of which will fit Universal Design standards and be actively marketed towards people with disabilities.

Wellesley | Community Housing Partners

$900,000 (VHTF)

$285,000 (HIEE)

City of Newport News

Wellesley is the substantial renovation of an existing three-story, 40-unit building in Newport News. All units will serve residents over the age of 55, with an income at or below 50% AMI. All units will be occupied by households receiving project-based Section 8 vouchers. The proposed acquisition and rehabilitation will include but is not limited to new flooring, roofing, windows, mechanical systems, appliances, cabinetry, kitchen and bathroom fixtures.

Cross Creek Rehab | Community Housing Partners

$600,000 (VHTF)

$546,000 (HIEE)

City of Portsmouth

Cross Creek Rehab is an existing affordable multifamily development in the city of Portsmouth comprised of 78 two- and three-bedroom garden-style apartments, which will serve families with incomes between 40-80% AMI. Seven units will be reserved for permanent supportive housing and eight for project-based vouchers. This project proposes new flooring, windows, mechanical systems, appliances and fixtures and increased accessibility for eight units.

HRHA Lineweaver Annex Renovation | Harrisonburg Housing and Redevelopment Authority

$900,000 (VHTF)

$230,000 (HIEE)

City of Harrisonburg

The Lineweaver Annex is an extensive rehabilitation rental project located in downtown Harrisonburg. This rehabilitation consists of 60 one-bedroom units designated for the elderly and persons with disabilities, and 20 of the 60 units will be reserved for permanent supportive housing.

Grayson Manor | Community Housing Partners

$900,000 (VHTF)

$161,180 (HIEE)

Grayson County

Grayson Manor is an existing 32-unit affordable senior development with one-bedroom, garden-style units. This project will acquire and renovate Grayson Manor, with rehabilitation to include new flooring, windows, mechanical systems, fixtures and appliances. In addition, five units will be made more accessible. The units will serve seniors with income at or below 60% AMI.

Leggett Building Apartments | Taylor Hollow Construction

$700,000 (HOME)

$239,700 (HIEE)

City of Radford

The Leggett Building Apartments will convert the former Leggett Building in Radford into 11 mixed-income rental units. Seven of the units will be for households earning up to and between 50% and 60% AMI, and four will be market rate. The project will include free broadband access for tenants and is located in downtown Radford.

Mt. Sterling Nine | Arlington Partnership for Affordable Housing

$900,000 (VHTF)

Loudoun County

Mt. Sterling Nine is the new construction of 48 rental units for seniors in Loudoun County. The project will be a mix of one- and two-bedroom apartments. Residents will have access to free Wi-Fi in unit and communal spaces, as well as access to community amenities, such as a business center and a fitness and wellness suite. Five units will be available for seniors at 30% AMI and the remaining 43 will be available for seniors at 50% AMI.

Oak Terrace | Hill Tide Housing Investments, LLC

$700,000 (VHTF)

City of Suffolk

Oak Terrace is the new construction of 120 two- and three-bedroom apartments across five three-story buildings in Suffolk. The buildings will be built to EarthCraft standards and include a playground, picnic shelter, a community building with laundry facilities, a computer room and exercise room. Twelve units will comply with ADA requirements, with three units equipped to serve individuals with sensory impairments. Commonwealth Catholic Charities will provide financial coaching, education and employment services to tenants.

Goose Creek Crossing | Hill Tide Housing Investments, LLC

$700,000 (VHTF)

City of Staunton

Goose Creek Crossing is the new construction of 116 units of two- and three-bedroom rental apartments across a 6.6 acre site in Staunton. The site will include a community building with an exercise room, computer room, laundry facilities, and management and maintenance offices. A playground and picnic shelter for resident use will also be onsite. The development will be served by Commonwealth Catholic Charities to provide resident services such as homeownership, financial counseling and employment services.

Expanding Affordable Housing 2020-2021 | Richmond Habitat for Humanity

$700,000 (VHTF)

City of Richmond

Expanding Affordable Housing is the new construction of eight affordable homes. The scattered-site homes will be available for purchase by families earning up to between 40% and 80% AMI. All homes will be built to EarthCraft and Energy Star standards and four will be built to meet Universal Design standards.

Mecklenburg Manor | NFP Affordable Housing Corporation

$700,000 (VHTF)

Mecklenburg County

Mecklenburg Manor is an extensive rehabilitation of an existing Section 8 and family complex. This rehabilitation will consist of eight buildings for a total of 51 units. This project will continue to prioritize Section-8 applicants, located in South Hill. Upon completion the project will be Enterprise Green Communities certified.

Sweetbriar II Apartments 2021 | People Inc. Housing Group

$517,000 (HIEE)

Washington County

Sweetbriar II Apartments is a new construction rental development located in Abingdon. This development will consist of 22 units in 11 duplex-style buildings and comprised of two- and three-bedroom garden-style townhome units. Five of the garden-style units will be fully accessible, and six will include Universal Design features. The accessible units will be subsidized with project-based Mainstream Vouchers with prioritization of low-income households with disabilities.

Covenant Heights VII | Hope Community Builders

$500,000 (HOME)

Rockingham County

Covenant Heights will consist of eight new construction homebuyer units in two buildings located in Rockingham County. These units will be used to help low-income and first-time homebuyers.

Cool Lane Apartments | Virginia Supportive Housing

$466,872 (HIEE)

Henrico County

Cool Lane Apartments is the adaptive re-use of a vacant building located in Henrico County. The project will renovate the former assisted living facility into permanent supportive housing for homeless and low-income individuals. The existing structure will be redesigned and adapted to create 86 units for homeless and low-income individuals earning 50% or less AMI from Henrico County and the city of Richmond.

Fifeville Rehab | Piedmont Housing Alliance

$300,000 (VHTF)

$32,500 (HIEE)

City of Charlottesville

Fifeville Rehab is the rehabilitation of five vacant units across three buildings in Charlottesville for the sale to households at or below 50% AMI. Improvements to the properties include the addition of solar panels, the modernization of kitchens and upgrades to promote energy-efficiency and home health.

712-714 High Street | Southside Community Housing and Development Corporation

$300,000 (HOME)

City of Petersburg

High Street is the new construction of 12 rental units in Petersburg. The one-, two- and three-bedroom apartments will be targeted for households earning up to and between 30% and 80% AMI. This project will contribute two permanent supportive units to the region. Two of the units will be accessible for physically impaired persons. This project will accompany the 714 High Street project already funded by ASNH, bringing 22 total units, 12 of which are permanent supportive housing.

Holly Court | Community Housing Partners

$231,220 (HIEE)

Lancaster County

Holly Court is the substantial rehabilitation of 40 one-bedroom senior apartments across three one-story buildings in Kilmarnock. All units will meet Universal Design standards, and five units will have additional design for accessibility under Section 504. Two units will be designed to serve residents who have hearing or visual impairments. Improvements include a new roof, gutters, downspouts, replacement of cabinets, countertops, appliances, lighting and bath fixtures, installation of low-flow faucets, shower heads, toilets and the replacement of the existing HVAC and water heater systems.

Mt. Sterling Four | Arlington Partnership for Affordable Housing

$200,000 (VHTF)

Loudoun County

Mt. Sterling Four is the new construction of 50 rental units for seniors in Loudon County. The project will be a mix of one- and two-bedroom apartments. Residents will have access to free Wi-Fi in unit and communal spaces, as well as access to community amenities, such as a business center and a fitness and wellness suite. Five units will be available for seniors at 30% AMI and five units will be available for seniors at 50% AMI, with the remaining 40 available for seniors at 60% AMI. Mt. Sterling Nine will be co-located with Mt. Sterling Nine.

Armstrong Renaissance | Better Housing Coalition

$200,000 (VHTF)

City of Richmond

Armstrong Renaissance is a new construction project of 36 homes for purchase in Richmond. Twenty-eight of the units will be at market rate, and eight will be for homebuyers at or below 80% AMI. The project provides $15,000 in down payment assistance to eligible homebuyers. The development is next to a new supermarket, a community college and a library.

EQUAL HOUSING OPPORTUNITY

Attachment 62

GOVERNOR YOUNGKIN ANNOUNCES OVER $93 MILLION IN AFFORDABLE AND SPECIAL NEEDS HOUSING LOANS

March 10, 2023

FUNDING WILL SUPPORT NEW CONSTRUCTION AND REHABILITATION OF OVER 3,936 AFFORDABLE AND SPECIAL NEEDS HOUSING UNITS

Governor Glenn Youngkin today announced more than $93 million in Affordable and Special Needs Housing loans for 57 projects across the Commonwealth. The recommended projects will create and preserve 3,936 total units for low-income and extremely low-income households, including 298 permanent supportive housing, 3,825 rental units and 111 units for sale as homeownership opportunities.

“Increasing Virginia’s supply of attainable, affordable and accessible housing is foundational to strengthening Virginia’s economy, and furthers my administration’s Make Virginia Home Plan,” said Governor Glenn Youngkin. “These awarded projects will create and preserve almost 4,000 units of affordable, quality housing for our most vulnerable residents.”

The Virginia Department of Housing and Community Development (DHCD) administers Affordable and Special Needs Housing (ASNH) loans, which combines state and federal resources to provide a simplified and comprehensive application process. Funding comes from four main sources: the federal HOME Investment Partnerships Program, the federal National Housing Trust Fund (NHFT), Housing Innovations in Energy Efficiency (HIEE), Permanent Supportive Housing (PSH) state funds and the Virginia Housing Trust Fund (VHTF).

VHTF is provided by the General Assembly and supports financing for housing construction projects that create or preserve affordable housing units, reduce the cost of affordable housing and increase homeownership. This funding is a key source of financing for these affordable housing initiatives to support moderate- and low-income families, as well as supporting homeless reduction grants to provide rapid re-housing and longer-term housing solutions for individuals experiencing chronic homelessness.

“Stable and affordable housing is vital to building a thriving economy, and we are aligning housing development resources to holistically fill this need across Virginia,” said Secretary of Commerce and Trade Caren Merrick. “Increasing the supply of affordable housing is integral to our economic development efforts as we continue to build an economy that works for all Virginians.”

Affordable and Special Needs Housing loans are awarded through a competitive process. Sixty-one applications were received for this round of funding, requesting more than $108 million. The funded projects will leverage over $1.39 billion in additional federal, state, local and private lending resources. To learn more about the ASNH program, visit www.dhcd.virginia.gov/asnh.

A FULL LIST OF THE 2022 FALL ASNH AWARDS CAN BE FOUND HERE.

Attachment 63

Community Flood Preparedness Fund Grants and Loans

Virginia Community Flood Preparedness Fund Grant

The Virginia Community Flood Preparedness Fund (CFPF) was established to provide support for regions and localities across Virginia to reduce the impacts of flooding.

Round 1 Grant Awards (Announced Oct. 5, 2021) see below

Round 2 Grant Awards (Announced Dec. 22, 2021) see below

Round 3 Grant Awards (Announced Sept. 28, 2022) see below

Round 3 Supplemental Grant Awards (Announced Dec. 30, 2022)

Download the list (Excel)

Structural floodwalls, stormwater system upgrades | $1,086,457
City of Chesapeake
Application (PDF) | **Scoring Sheet** (PDF)

Resilience planning and staffing | $331,740
City of Danville
Application (PDF) | **Scoring Sheet** (PDF)

Ghent-Downtown-Harbor Park flood protection barrier system | $24,628,800
City of Norfolk
Application (PDF) | **Scoring Sheet** (PDF)

Mayo Island acquisition | $7,500,000
City of Richmond
Application (PDF) | **Scoring Sheet** (PDF)

Planning and capacity building | $59,221
City of Salem
Application (PDF) | **Scoring Sheet** (PDF)

27 Fairfax County watershed studies | $600,000
Fairfax County
Application (PDF) |

Chowan Avenue stormwater improvement project | $1,200,000
Fairfax County
Application (PDF) | **Scoring Sheet** (PDF)

Tripps Run at Barrett Road | $8,985,200
Fairfax County
Scoring Sheet (PDF)

Tucker Avenue neighborhood stormwater improvement | $4,894,000
Fairfax County
Application (PDF) | **Scoring Sheet** (PDF)

Captain Sinclair's Recreation Area comprehensive flood mitigation | $102,200
Gloucester County
Application (PDF) | **Scoring Sheet** (PDF)

Resilience planning and assessments | $15,000
Hampton Roads Planning District Commission
Application (PDF) | **Scoring Sheet** (PDF)

Studies to support resilience plans, policies, and projects | $115,010
Hampton Roads Planning District Commission
Application (PDF) | **Scoring Sheet** (PDF)

Davis Creek channel dredging and novel dredging spoils reuse | $876,969.23
Mathews County
Application (PDF) | **Scoring Sheet** (PDF)

East River Boat Yard resilience enhancements | $371,287.45
Mathews County
Application (PDF) | **Scoring Sheet** (PDF)

Whites Creek Public Landing resilience enhancements | $96,401.54
Mathews County
Application (PDF) | **Scoring Sheet** (PDF)

Mobjack Watershed individual property shoreline protection projects | $363,890
Middle Peninsula Planning District Commission
Application (PDF) | **Scoring Sheet** (PDF)

Piankatank/Moore Creek individual property shoreline protection projects | $53,637.50
Middle Peninsula Planning District Commission
Application (PDF) |

York River Watershed individual property shoreline protection projects | $135,016
Middle Peninsula Planning District Commission
Application (PDF) |

Whiting Creek comprehensive resilience enhancements | $70,000
Middlesex County
Application (PDF) | **Scoring Sheet** (PDF)

Staffing and planning assessments | $150,155
Northampton County
Application (PDF) | **Scoring Sheet** (PDF)

Planning and capacity building | $37,500
Rappahannock-Rapidan Regional Commission
Application (PDF) | **Scoring Sheet** (PDF)

Study to evaluate stormwater and flood resilience | $84,902.50
Town of Occoquan
Application (PDF) | **Scoring Sheet** (PDF)

Round 3 Grant Awards (Announced Sept. 28, 2022)

Staffing, planning and assessments | $375,000.00
Accomack-Northampton PDC
Application (PDF) | **Scoring Sheet** (PDF)

Resilience Plan | $54,000.00
Central Virginia Planning District Commission
Application (PDF) | **Scoring sheet** (PDF)

Staffing and planning assessments | $332,505.00
Tazewell County
Application (PDF) | **Scoring sheet** (PDF)

Floodplain staff and resilience plan | $54,000.00
Town of Buchanan
Application (PDF) | **Scoring sheet** (PDF)

Resilience Plan and floodplain staff capacity | $140,590.00
City of Covington
Application (PDF) | **Scoring sheet** (PDF)

Resilience Planning | $75,656.00
Grayson County
Application (PDF) | **Scoring sheet** (PDF)

Resilience Planning | $51,300.00
Town of Clintwood
Application (PDF) | **Scoring sheet** (PDF)

Staffing capacity | $2,969.37
Shenandoah County
Application (PDF) | **Scoring sheet** (PDF)

Drainage study | $357,380.00
City of Covington
Application (PDF) | **Scoring sheet** (PDF)

H&H Studies to Update FEMA Maps | $90,000.00
Town of Front Royal
Application (PDF) | **Scoring sheet** (PDF)

Finney Outfall to Nansemond River Drainage Area Study in Downtown Suffolk | $65,593.00
City of Suffolk
Application (PDF) | **Scoring sheet** (PDF)

Acquisition, flood proofing, restoration | $2,232,415.00
Dickenson County
Application (PDF) | **Scoring sheet** (PDF)

Riverside Memorial Cemetery Shoreline Stabilization | $1,120,000.00
City of Norfolk
Application (PDF) | **Scoring sheet** (PDF)

Storm water system | $2,800,878.00
City of Petersburg
Application (PDF) | **Scoring sheet** (PDF)

First Colonial Road and Oceana Boulevard Stormwater Improvements | $2,021,662.50
City of Virginia Beach

Application (PDF) | **Scoring sheet** (PDF)

Resilience Planning | $119,755.00
City of Fairfax
Application (PDF) | **Scoring sheet** (PDF)

Resilience Plan | $30,300.00
King George County
Application (PDF) | **Scoring sheet** (PDF)

Floodplain staff and resilience plan | $118,313.00
Albemarle County
Application (PDF) | **Scoring sheet** (PDF)

Resource Assessments, planning, strategies, development | $94,545.00
Henrico County
Application (PDF) | **Scoring sheet** (PDF)

2-Dimensional Stormwater Management Model for Meadow Creek and Rivanna River Watersheds | $275,000.00
City of Charlottesville
Application (PDF) | **Scoring sheet** (PDF)

Study to assess changes in watershed hydrology using existing streamflow and precipitation monitoring data from Four Mile Run | $68,974.00
Northern Virginia Regional Commission
Application (PDF) | **Scoring sheet** (PDF)

Kimberly Bridge Feasibility Study | $149,373.50
City of Suffolk
Application (PDF) | **Scoring sheet** (PDF)

Mosby Wood Floodplain Improvement Study | $24,286.00
City of Fairfax
Application (PDF) | **Scoring sheet** (PDF)

Hydraulic and hydrologic study of the Goose Creek watershed/floodplain | $92,500.00
City of Chesapeake
Application (PDF) | **Scoring sheet** (PDF)

Inlet Capacity and New Inlet Program ("Inlet Program") | $764,000.00
City of Alexandria
Application (PDF) | **Scoring sheet** (PDF)

Mount Vernon Dual Corrugated Metal Pipe Culvert Replacement and Optimization | $1,250,000.00
City of Alexandria
Application (PDF) | **Scoring sheet** (PDF)

Gambles Mill Pump Station | $870,244.00
Henrico County
Application (PDF) | **Scoring sheet** (PDF)

Supplemental Review List (PDF)

Round 2 Grant Awards (Announced Dec. 22, 2021)

Waterfront Improvement Project Design (PDF) | $3,241,200
City of Alexandria

Arlandria Flood Mitigation – Edison Street and Dale Street Capacity Project Phase I (PDF) | $516,500
City of Alexandria

Staff Training and Certification (CFM) (PDF) | $2,579
Town of Ashland

Resilience Plan (PDF) | $60,051
Town of Ashland

Resilience Planning and Staff Training (PDF) | $94,276
City of Charlottesville

Resilience Plan (PDF) | $44,520.30
Town of Christiansburg

Resilience Plan Development and Training (PDF) | $103,500
Town of Colonial Beach

Big Bethel Blueway; Albany Drive at Big Bethel Road (PDF) | $3,008,500
City of Hampton

Sunset Creek Urban Channel Naturalization Project (PDF) | $2,022,143
City of Hampton

Billy Woods Canal (PDF) | $291,850
City of Hampton

Lake Hampton and North Armistead Avenue (PDF) | $3,841,544
City of Hampton

Pilot Project Development; Dashboard; Education and Outreach (PDF) | $361,500
Henrico County

Resilience Plan Development and Training (PDF) | $68,026
Isle of Wight County

Capacity Building and Planning (PDF) | $150,000
Lenowisco PDC

MPPDC Capacity Building (PDF) | $35,250
Middle Peninsula PDC

Dredging Project (PDF) | $336,000
Middlesex County

Master Plan Development, Stormwater, Floodplain, Resilience and Climate Change Management (PDF) | $4,926,063
City of Newport News

Watershed Master Plan Study and Purchase of Flood Sensors (PDF) | $315,000
City of Norfolk

Hazard Mitigation Plan Update (PDF) | $45,000
Northern Neck PDC

Data collection of regional significance, creation of tools and applications, dashboard for real-time flooding risk data (PDF) | $11,250
Northern Virginia Regional Commission

Resilience Plan Development and Staff (PDF) | $385,016
City of Petersburg

Comprehensive Citywide Drainage Study and FP Ordinance Update (PDF) | $2,238,542
City of Petersburg

Planning and Capacity Building-Staff (PDF) | $23,153
City of Richmond

Resilience Plan Development - Windsor Farms (PDF) | $19,394
City of Richmond

Resilience Plan Development (PDF) | $135,000
City of Roanoke

Town of Scottsville Study (PDF) | $123,346
Town of Scottsville

Capacity Building for Flood Resilience in Southern Virginia (PDF) | $135,000
Southside Planning District Commission

Hoskins Creek and Rappahannock River (PDF) | $69,920
Town of Tappahannock

Stormwater Project -South Birdneck Road between Hughes Avenue and Sea Street (PDF) | $1,925,000
City of Virginia Beach

West Point Study (PDF) | $22,800
Town of West Point

Round 1 Grant Awards (Announced Oct. 5, 2021)

Eastern Branch of Elizabeth River Wetland and Floodplain Restoration (PDF) | $3,000,000
City of Virginia Beach

McGuire and Chapel Drive Drainage Improvements Project (PDF) | $1,100,000
City of Richmond

Norfolk Coastal Storm Risk Management Analysis (PDF) | $900,000
City of Norfolk

Portsmouth's Data-Driven and Equity-Driven Resilience Strategy (PDF) | $527,949
City of Portsmouth

Lake Whitehurst Watershed Study (PDF) | $500,000
City of Norfolk

Plans and Capacity Building with Consultant Services (PDF) | $387,500
Buchanan County

Oyster Plan - Capacity Building and Resilience Planning (PDF) | $202,232
Northampton County

Resilient Hampton: Downton Hampton, Phoebus and Buckroe Beach (PDF) | $158,681
City of Hampton

Moores Creek Watershed (PDF) | $153,500
City of Charlottesville

Honor Park Resilience Project (PDF) | $147,994
City of Hampton

Mill Point Living Shoreline (PDF) | $126,498
City of Hampton

Resilient Stormwater Capacity and Green Streets Project (PDF) | $115,200
City of Alexandria

Richmond Manchester and Shockoe Bottom Neighborhoods (PDF) | $103,500
City of Richmond

Southern Chesapeake - Watershed 5 (PDF) | $91,404
City of Chesapeake

Resilience Plan (PDF) | $74,997
City of Chesapeake

Capacity Building and Planning (PDF) | $68,024
City of Suffolk

Resilience Plan (PDF) | $65,040
City of Winchester

The Impacts of Climate Change on Crop Planning and Production: An Agricultural Study of the Eastern Shore (PDF) | $47,121
Accomack-Northampton Planning District Commission

Carlton Road Boat Ramp, Wake, Virginia - Design and Permitting (PDF) | $26,400
Middle Peninsula Planning District Commission (Middlesex County)

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Attachment 64

ENERGY + ENVIRONMENT GOVERNMENT + POLITICS

Flood Fund future uncertain as Youngkin pushes for carbon market withdrawal

State racks up $203 million for flood protection from RGGI revenues

BY: **CHARLIE PAULLIN** - SEPTEMBER 30, 2022 12:02 AM

Increased precipitation and sea level rise are leading to more frequent flooding in Virginia. (NBC12)

In January, strong winds led to high tides drowning parts of Hampton. Some roads were impassable, with water levels rising to near the top tread of the tires. Almost two years prior, stormwater had led to flooding severe enough to sweep parked cars down the roadways.

With climate change driving sea levels up and altering rainfall patterns, Hampton is certain to continue to be hit by flooding. What's less certain is where it will get funding to combat it.

Over the past two years, Virginia has accumulated over $200 million for flood protection from the state's participation in the Regional Greenhouse Gas Initiative. But the future of that funding pool is in doubt as Republican Gov. Glenn Youngkin has made it clear he wants to leave the initiative.

Gov. Glenn Youngkin. (Ned Oliver / Virginia Mercury)

"RGGI is a bad deal for Virginia," said Travis Voyles, acting secretary of natural and historic resources, when he outlined the administration's plans for withdrawing Virginia from RGGI at the end of last month.

RGGI is the 11-state cap-and-invest program in which energy producers must buy allowances at auction for the carbon they emit, and a cap is placed on overall carbon emissions.

The proceeds of those auctions are returned to the state. In Virginia, half is directed to low-income energy efficiency programs, while 45% goes toward the Community Flood Preparedness Fund, a pool of money that provides flood assistance to communities and local governments.

Including the latest sale of allowances on Sept. 7, Virginia has received some $452 million from RGGI, meaning $203 million will go toward flood resiliency efforts.

Local flood protection

Whether flooding occurs on Virginia's coast from sea level rise or in its inland areas from rainfall increases, the impacts are real, said Skip Stiles, executive director of Wetlands Watch, a Norfolk-based nonprofit working to address sea level rise adaptation, floodplain management and other waterway impacts.

Prior to Virginia joining RGGI in 2020 – a Democratic priority during the party's brief period in power – flood protection was left up to local and regional planning bodies, with no central pool of funds governments could draw from. Since the state joined, the Department of Conservation and Recreation, which administers the Flood Fund, has begun paying out grants from the revenues.

"Before Virginia joined RGGI there were ZERO state dollars going toward these resilience efforts," said Stiles in an email.

Any state spending on these efforts through the Virginia Coastal Zone Management Program, Virginia Sea Grant or the Virginia Department of Emergency Management used money derived from federal agencies, he said.

“We have to assume that if we leave RGGI we will return to that low-priority status for this work,” Stiles said.

The Flood Fund has proved to be “absolutely helpful” to combat problems linked to climate change, particularly stormwater issues and sea level rise, said City of Hampton Resiliency Officer Carolyn Heaps-Pecaro.

“We have a lot of projects lined up,” she said. “We have a lot of ideas for how to fix the town. We need that money to actually make them a reality.”

Hampton was the largest recipient of the second round of grants announced in December from the proceeds, receiving about a third of the $24.5 million the Flood Fund paid out. The projects that were funded included plans for elevating a roadway, improving drainage canals and reducing nutrient pollution.

Millions in local funding is needed to complete the projects, but the state funds help cover design and engineering costs to begin them, Heaps-Pecaro said.

“Several of these projects probably would not have moved forward nearly as quickly as they did had we not received the grant funding,” she said.

Flood Fund dollars also go toward projects outside of coastal areas. In the first round of grants, announced in October 2021, $400,000 was awarded to Buchanan County.

An underpass in Big Rock, Buchanan County, on Aug. 31, 2021. (Sarah Vogelsong / Virginia Mercury)

The Southwestern Virginia locality had been slammed with devastating floods the prior August. The region also suffered severe flooding this July and, according to a Thursday morning update from the National Hurricane Center and Central Pacific Hurricane Center, could lie in the pathway of Hurricane Ian.

The Buchanan funding is intended to go toward an engineering analysis that would lead to a local flood resilience plan and training for a staff member to become a certified floodplain manager.

A quarter of Flood Fund dollars need to go to low-income communities, a designation Buchanan qualifies for, with a median income that in 2019 was less than half of the state's average.

"Buchanan County and our neighbors in Southwest Virginia have experienced devastating recurrent flooding that has increased in recent years," the county's application stated. "Flooding is often thought of as a coastal problem, but we are pleased to see that DCR seeks to direct some of this fund to mountainous and disadvantaged communities such as ours."

An unclear future

While Youngkin has been adamant that he believes Virginia should withdraw from RGGI, the administration's plans for how the state will help local governments pay for the massive costs of flood protection are less clear.

Youngkin has been arguing for months that RGGI proceeds are being generated from an unfair "tax" on electric utility ratepayers. Virginia utilities, which are responsible for about three-quarters of the carbon emissions subject to RGGI, are allowed to pass on the cost of buying allowances to their customers, an approach Youngkin says is flawed.

"RGGI was sold to Commonwealth residents as a deal that returned the 'proceeds' to the ratepayers to offset the costs of the program, but that is not what is happening," a statement from the governor's office to the Mercury said. "We can provide funding for flood resiliency in a transparent way without using an RGGI tax on Virginians."

Youngkin's office said the administration intends to develop a plan to provide direct funding for flood resiliency with the General Assembly. That would require buy-in from Senate Democrats.

But when pressed for specifics of the plan, such as whether it will be crafted through legislation or the budget process, which can involve fluctuating revenues and regular competition among different interests competing for a piece of the pie, the governor's office didn't clarify beyond saying it will "provide direct funding and coordination for flood resiliency."

“We can do this in a way that is transparent and not a hidden tax that was misrepresented to Virginians,” the governor’s office stated. “This will ensure we have a long-term comprehensive strategy to sustain flood resilience efforts in Virginia.”

Millions of dollars remain uncommitted

Even while the future of the Flood Fund remains uncertain, millions of dollars remain on its books.

Before leaving office, Gov. Ralph Northam’s administration awarded two rounds of grants in the last three months of 2021 equal to $32.3 million.

A third round of $13.6 million was announced Wednesday, nine months into Youngkin’s term.

Flood Fund oversight to remain with executive branch

Virginia’s Community Flood Preparedness Fund, a pot of millions of dollars earmarked for community flood protection work across the state, will remain under the oversight of the executive branch despite recent legislative efforts to shift authority to an appointed citizen board. Gov. Glenn Youngkin has vetoed legislation that would have transferred administration of the Flood … Continue reading

Virginia Mercury

Round 3 was initially advertised to award $40 million, but with applications requesting nearly $93 million, DCR said it has been authorized to release an additional $30 million. The agency is allowing 32 applicants to revise and resubmit their proposals and plans to make a decision on them by the end of the year.

If DCR awards all $70 million it’s been authorized to grant during the third round, Virginia will have spent about 50% of its Flood Fund revenues to date, with just over $100 million left to be designated.

A DCR spokesperson said plans for that unused funding include “future grant rounds as well as loan opportunities going forward.” A fourth application round is expected to be opened in early 2023, along with the first round of the newly created Resilient Virginia Revolving Loan

Fund, which will provide loans or grants for resilience to not only local governments, but also residents.

Increasing climate impacts

Stiles pointed to data from Carnegie Mellon University, the Northeast Regional Climate Center at Cornell University and the RAND Corporation showing that rainfall intensity has increased an average of 18% since 2006.

Increased rainfall in the state has been documented for years, and the Virginia Coastal Resilience Master Plan projects that between 2020 and 2080, the number of residents living in homes exposed to major coastal flooding will grow from approximately 360,000 to 943,000, an increase of 160%. The report also found that more residential, public and commercial buildings will be exposed to extreme coastal flooding, while annualized flood damages will increase from $0.4 to $5.1 billion.

What's more, a recent Climate Central study found that rising water levels on land reduce the amount of property that local governments can tax.

"Climate change isn't going away," Heaps-Pecaro stated. "We have to accelerate" the fight against it.

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CHARLIE PAULLIN

Charles Paullin covers energy and environment for the Mercury. He previously worked for Northern Virginia Daily in the Northern Shenandoah Valley and for the New Britain Herald in central Connecticut

Virginia Daily in the Northern Shenandoah Valley and for the New Britain Herald in central Connecticut. An Alexandria native, Charles graduated from the University of Hartford initially wanting to cover sports. He's received several Virginia Press Association awards for his coverage of crime, local government and state politics. Catch him in nature experiencing all the outdoors has to offer, and contact him at cpaullin@virginiamercury.com.

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Attachment 65

AFFORDABLE AND SPECIAL NEEDS HOUSING (ASNH)

HOME Funds

The HOME Program: HOME Investment Partnerships are grants to states and units of general local government to implement local housing strategies designed to increase homeownership and affordable housing opportunities for low- and very-low-income Americans

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National Housing Trust Fund

The National Housing Trust Fund is an affordable housing production program that complements existing Federal, state and local efforts to increase and preserve the supply of decent, safe and sanitary affordable housing for extremely-low- and very-low-income households, including homeless families.

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Virginia Housing Trust Fund Competitive Loan Pool

The Virginia Housing Trust Fund is intended to create and preserve affordable housing and to reduce homelessness in the commonwealth.

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Home Innovations In Energy Efficiency (HIEE)

RGGIis a market-based collaborative effort among Northeast and Mid-Atlantic states to combat climate change and reduce greenhouse gas emissions from the power sector, while driving economic growth. Proceeds from the RGGI cap and trade program to energy efficiency programs will benefitlow-income Virginians by making investments in affordable housing.

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Attachment 66

ENERGY + ENVIRONMENT

THE BULLETIN

Virginia looking to loans for local flood resiliency efforts

BY: **CHARLIE PAULLIN** - OCTOBER 10, 2022 12:02 AM

Flooding at Rockett's Landing in Richmond. (NBC 12)

HAMPTON – The head of the Department of Conservation and Recreation said Virginia would begin using more loans rather than just relying on grants to fund local flood resiliency efforts.

DCR Director Matt Wells told the Joint Subcommittee on Recurrent Flooding Thursday his agency is looking to tap into the new Resilient Virginia Revolving Loan Fund as well as the Community Flood Preparedness Fund, also known as the Flood Fund.

"I think if you were looking at a Venn diagram of the two, the circles wouldn't be quite the same, but they would be significantly overlapped," Wells said.

The revolving fund was created through legislation in the last session by state Sen. Lynwood Lewis, D-Accomack, and Del. David Bulova, D-Fairfax, to provide localities and people with loans for flood resiliency efforts.

The revolving fund was appropriated $25 million in the budget with Flood Fund dollars, which have been generated through the state's participation in the Regional Greenhouse Gas Initiative. The Flood Fund has received just over $200 million since Virginia joined in 2020.

The difference between the two funds lies around the intended audience: the revolving fund is available for residential, commercial and industrial properties, whereas the Flood Fund is directed toward community-scale projects, Wells explained.

The revolving fund is also designed to be self-sustaining.

A DCR spokesperson previously told the Mercury future awards of Flood Fund dollars would include loan opportunities.

"Part of the reason we are considering doing loans through the CFPF is because that's a potentially larger pot of money that could be leveraged," Wells said Thursday.

Chris Stone, the CEO of architecture firm Clark Nexsen and the business representative on the subcommittee, questioned if the revolving fund is substantial enough for the demand.

"The $25 million ... it won't even really do a simple project, a substantial project," Stone said.

Lewis, who chairs the subcommittee, said the funds would provide gap funding for projects.

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Attachment 67

JUDITH WILLIAMS JAGDMANN
COMMISSIONER

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COMMISSIONER

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

BERNARD LOGAN
CLERK OF THE COMMISSION
P.O. BOX 1197
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September 1, 2022

The Honorable Glenn A. Youngkin
Governor, Commonwealth of Virginia

The Honorable Richard L. Saslaw
Chairman, Senate Committee on Commerce and Labor

The Honorable Kathy J. Byron
Chairman, House Committee on Commerce and Energy

Members of the Commission on Electric Utility Regulation

Ladies and Gentlemen:

Please find enclosed the Virginia State Corporation Commission's Status Report on the Implementation of the Virginia Electric Utility Regulation Act pursuant to § 56-596 B of the Code of Virginia.

Please let us know if we may be of further assistance.

Respectfully submitted,

Jehmal T. Hudson
Chairman

Judith Williams Jagdmann
Commissioner

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

Report to the Governor of the Commonwealth of Virginia,
the Chairman of the Senate Committee on Commerce and Labor,
the Chairman of the House Committee on Commerce and Energy,
and the Commission on Electric Utility Regulation
of the Virginia General Assembly

Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant to § 56-596 B of the Code of Virginia

September 1, 2022

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Appendix 1: Glossary of Terms

EXECUTIVE SUMMARY

This document contains the report of the Virginia State Corporation Commission ("Commission") pursuant to § 56-596 B of the Code of Virginia ("Code"), which directs the Commission to provide an update by September 1 of each year on the status of the implementation of the Virginia Electric Utility Regulation Act, Code §§ 56-576 through 56-596.3 ("Regulation Act"). The Regulation Act has expanded in recent years with new programs and requirements that fall within the Commission's purview. This report summarizes the Commission's efforts to implement the Regulation Act for incumbent electric utilities[1] as well as the electric cooperatives.

Key highlights from the report include:

A. Current Status of the Regulation Act

- Over the past several years, the Regulation Act has been amended to require new or expanded programs and rulemakings that apply to the Commonwealth's incumbent electric utilities and electric cooperatives. These programs include ones that implement the requirements of the Virginia Clean Economy Act ("VCEA").[2] The VCEA includes provisions establishing mandatory Renewable Energy Portfolio Standard ("RPS") and Energy Efficiency Resource Standard. The relevant Commission dockets that implement or update these programs, as well as the dockets that continue to provide oversight of the utility's existing operations, are summarized in Section IV, below.

- On November 18, 2021, the Commission issued its Final Order concerning its triennial review of Dominion Energy Virginia's ("DEV") rates, terms, and conditions for the provision of generation, distribution, and transmission services.[3]

[1] Code § 56-580 G generally suspends application of the Regulation Act to Kentucky Utilities, d/b/a Old Dominion Power Company ("KU/ODP"), which is an investor-owned incumbent electric utility whose service territory is located entirely within Dickenson, Lee, Russell, Scott, and Wise Counties. However, certain provisions of the Regulation Act, including Code §§ 56-585.5 and 56-594, have been made applicable, at least in part, to KU/ODP.

[2] 2020 Va. Acts chs. 1193, 1194.

[3] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms, and conditions for the provision of generation, distribution,and transmission services pursuant to § 56-585.1 A*

- On January 7, 2022, the Commission issued a Final Order concerning its review of DEV's petition for approval of Phase II of its Grid Transformation ("GT") Plan.[4] The approved GT Plan investments focus on grid reliability and are designed to accommodate or facilitate the expected increase in distributed energy resources. Approved Phase II investments include (i) advanced metering infrastructure; (ii) the customer information platform; (iii) grid infrastructure, which comprises targeted corridor improvement and voltage island mitigation; (iv) grid technologies; (v) telecommunications; (vi) cyber security; (vii) physical security; and (viii) customer education. The projected capital and operations expenses for Phase II are projected to be approximately $776 million. The Commission's approval of these projects was made subject to certain contingencies, cost caps, and reporting requirements.

- On March 15, 2022, the Commission issued a Final Order concerning its review of DEV's 2021 RPS Filing which included (i) DEV's RPS Development Plan (encompassing proposed development of new solar, onshore wind, and energy storage resources); (ii) requests for approval to construct 13 new utility-scale projects and to enter into 24 new purchase power agreements ("PPAs"); and (iii) DEV's request for approval of revised Rider CE. The Commission (i) found that, for the limited purpose of filing its second annual RPS plan under Code § 56-585.5 D 4, DEV's plan was reasonable and prudent; (ii) approved the utility-scale projects and PPAs proposed by the Company; and (iii) approved revised Rider CE.[5]

- On July 1, 2022, the Commission issued a Final Order concerning its review of DEV's request for approval of a rate adjustment clause, designated Rider SNA, for costs associated with preparing Petitions for Subsequent License Renewal to the Nuclear Regulatory Commission to extend the operating licenses of, and the projects reasonably appropriate to upgrade or replace systems and equipment deemed to be necessary to operate safely and reliability, Dominion's Surry Units 1

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of the Code of Virginia, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

[4] *Petition of Virginia Electric and Power Company, For approval of a plan for electric grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia,* Case No. PUR-2021-00127, Doc. Con. Cen. No. 22010126, Final Order (January 7, 2022).

[5] *Petition of Virginia Electric and Power Company, For approval of the RPS Development Plan, approval and certification of the proposed CE-2 Solar Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under § 56-585.1 A 6 of the Code of Virginia, and a prudence determination to enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia,* Case No. PUR-2021-00146, Doc. Con. Cen. No. 220320113, Final Order (March 15, 2022) (approving 857 megawatts ("MW") of new solar generation capacity and 103 MW of energy storage capacity). The Commission previously approved 498 MW of new solar facilities for Dominion. *See Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing 2020 RPS Proceeding for Virginia Electric and Power Company,* Case No. PUR-2020-00134, 2021 S.C.C. Ann. Rept. 242,243, Final Order (April 30, 2021).

and 2 and North Anna Units 1 and 2 in an extended period of operation.[6] The Commission adopted a proposed Stipulation in that case and approved the Petition as modified by the Stipulation.

- On July 15, 2022, the Commission issued its Final Order concerning Appalachian Power Company's ("APCo") 2021 RPS Plan. The Commission: (i) found APCo's RPS Development Plan is reasonable and prudent for the limited purpose of its second annual plan; (ii) approved APCo's requests for approval of cost recovery for 313.9 MW of solar and onshore wind capacity, including both company-owned resources and PPAs; (iii) granted APCo's request for a prudency determination for 238.9 MW of solar capacity, including company-owned resources and PPAs; (iv) approved the recovery of projected costs of renewable energy certificates ("RECs") purchased in the PJM[7] REC market; and (v) approved rate adjustment clauses ("RACs") for cost recovery.[8] The Commission also established additional directives regarding APCo's modeling in its subsequent RPS Plans.[9] The Commission further directed APCo to continue filing a consolidated bill analysis in its RPS Filings.

- On August 5, 2022, the Commission issued a Final Order approving requested cost recovery associated with DEV's proposed 2,587 MW Coastal Virginia Offshore Wind Commercial Project ("CVOW Project") to be located in a federal lease area off the coast of Virginia Beach, Virginia.[10] The project consists of 176 wind turbines, each designed to generate 14.7 MW. The project is expected to have a capital cost of $9.8 billion and will likely be the largest capital investment, and single largest project, in the history of Dominion Energy Virginia. The Commission also approved the electric interconnection and transmission facilities to connect the CVOW Project reliably with the existing transmission system. DEV and Consumer Counsel have requested the Commission reconsider aspects of the Final Order.

---

[6] *Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider SNA under § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00229, Doc. Con. Cen. No. 220710001, Final Order (July 1, 2022).

[7] PJM Interconnection, L.L.C. ("PJM")

[8] *Petition of Appalachian Power Company, For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia and related requests*, Case No. PUR-2021-00206, Doc. Con. Cen. No. 220720045, Final Order on Petition and Associated Requests, and Order Bifurcating Proceeding (July 15, 2022).

[9] *See, e.g., id.* at 6-7.

[10] *Application of Virginia Electric and Power Company, For approval and certification of the Coastal Virginia Offshore Wind Commercial Project and Rider Offshore Wind, pursuant to § 56-585.1:11, § 56-46.1, § 56-265.1 et seq. and § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00142, Doc. Con. Cen. No. 220820117, Final Order (August 5, 2022).

- On August 10, 2022, the Commission issued a Final Order in DEV's annual demand-side management ("DSM") filing that approved, among other things, (i) DEV's proposed Phase X DSM Programs including proposed enhancement and expansion of certain previously approved programs; (ii) reorganization and consolidation of the DEV's DSM Portfolio; and (iii) cost recovery through associated RACs.[11] The Commission had previously approved, on September 7, 2021, the DEV's application seeking (i) approval of the Company's Phase IX DSM programs, including 11 new energy efficiency and demand response programs; (ii) the expansion and modification of certain existing programs; and (iii) approval of cost recovery through associated RACs.[12]

- Both APCo (a Phase I Utility) and DEV (a Phase II Utility) estimate that they are on target to implement energy efficiency programs and measures to achieve the total annual energy savings targets for 2023 as specified by Code § 56-596.2.

B. Rate and Capital Outlook

DEV

- DEV's typical[13] monthly residential bill has increased by $46.34 to $136.93[14] (a 51.15% increase) from July 1, 2007,[15] to July 1, 2022. Over the 12 months ended July 1, 2022, DEV's typical monthly residential bill has increased by $15.65.

- DEV did not file an Integrated Resource Plan ("IRP") in 2021. In accordance with Code § 56-599, DEV's next IRP will be due by May 1, 2023.

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[11] *Petition of Virginia Electric and Power Company, For approval of its 2021 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUR-2021-00247, Doc. Con. Cen. No. 220830003, Final Order (August 10, 2022).

[12] *Application of Virginia Electric and Power Company, For approval of its 2020 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUR-2020-00274, 2021 S.C.C. Ann. Rept. 350, Final Order (September 7, 2021).

[13] For purposes of this report, a typical residential bill is based on usage of 1,000 kilowatt-hours ("kWh") per month.

[14] This amount includes an interim fuel factor rate of $0.35379 which is subject to change pending a final order in Case No. PUR-2022-00064. *Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to § 56-249.6*, Case No. PUR-2022-00064, Doc. Con. Cen. No. 220540002, Order Establishing 2022-2023 Fuel Factor Proceeding (May 24, 2022).

[15] Enactment Clause 7 of 2007 Va. Acts chs. 888 and 933 requires the Commission, in consultation with the Office of the Attorney General, to "submit a report to the Governor and General Assembly by November 1, 2012, and every five years thereafter, assessing the rates and terms and conditions of incumbent electric utilities in the Commonwealth." The first five-year window for this rate assessment was 2007-2012. The Commission begins its rate analysis with the year 2007 in this report to coincide with this window.

- On November 18, 2021, the Commission issued a Final Order in DEV's first triennial review, covering the period 2017 – 2020.[16] The Commission approved a Stipulation among DEV, Commission Staff, and certain case participants.[17] The Stipulation provided for customer refunds, totaling $330 million, the statutory maximum annual rate reduction of $50 million, and customer credit reinvestment offsets of $309 million.[18] For a typical residential customer, this results in a decrease of approximately $0.90 per month effective January 1, 2022 and refunds totaling approximately $67.00 over the 2022-2023 period. The Commission also approved a 9.35% return on common equity ("ROE") as fair and reasonable for the 2021 – 2023 period that will be the subject of DEV's next triennial review.[19]

- As reported by DEV, its base rate financial results for 2021 reflect an actual earned ROE of 11.49%, which is above its authorized ROE of 9.35%.[20] DEV's 2021 financial results will be audited as part of its next triennial review, which will be filed in 2024 and will cover the period 2021 – 2023.

- In a February 2022 presentation to investors, DEI[21] identified DEV capital investments of approximately $27.9 billion for the five-year period 2022 – 2026, including investments in wind and solar generation, energy storage, nuclear facility relicensing, transmission, distribution undergrounding, and grid transformation. These investments would reflect a 74% increase in DEV's rate base by 2026, with 55% being recovered from customers through RACs.

APCo

- APCo's typical monthly residential bill has increased by $55.64 to $122.25 (an 83.53% increase) from July 1, 2007, to July 1, 2022. Over the 12 months ending July 1, 2022, APCo's typical monthly residential bill has increased by $5.16.

- On August 18, 2022, the Supreme Court of Virginia issued its opinion on the appeals of APCo and the Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel") concerning the Commission's decision in APCo's

[16] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms, and conditions for the provision of generation, distribution, and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

[17] The remaining participants did not join, but did not oppose, the Stipulation. *Id.* at 2-3.

[18] *Id.* at 3.

[19] *Id.* at 5.

[20] *Id.*

[21] Dominion Energy, Inc. ("DEI").

2020 Triennial Review.[22] The Court affirmed in part, reversed in part, and remanded the case to the Commission for further proceedings consistent with the Court's opinion.[23]

- As reported by APCo, its base rate financial results for 2021 reflect an actual earned ROE of 5.38%, which is below its authorized ROE of 9.20%.[24] APCo's 2021 financial results will be audited as part of its next triennial review, which is due to be filed by March 31, 2023, and will cover the period 2020 – 2022.

- APCo filed its 2022 IRP on April 29, 2022. Based on APCo's billing analysis, showing projected annual impacts to a residential bill over the next five years incorporating the requirements of the VCEA, the monthly bill of a Virginia residential customer using 1,000 kWh per month is projected to be between $141.73 and $143.07 by 2026, an increase of between $19.50 and $20.84 per month over the April 29, 2022 typical residential bill (or an estimated annual increase of $234.00 to $250.08).[25] APCo's 2022 IRP is pending before the Commission and an evidentiary hearing is scheduled to begin on October 25, 2022.[26]

[22] *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, 2020 S.C.C. Ann. Rept. 421, Final Order (November 24, 2020).

[23] *Appalachian Power Co. v. State Corp. Comm'n*, Record No. 210391 (Va. Aug. 18, 2022).

[24] The authorized ROE of 9.20% was set in the Commission's Final Order in Case No. PUR-2020-00015.

[25] The projected monthly bill increases of $19.50 and $20.84 are based on the 2022 IRP Least Cost Plan and Hybrid Plan, respectively.

[26] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2022-00051, Doc. Con. Cen. No. 220540021, Order for Notice and Hearing (May 24, 2022).

I.
INTRODUCTION

The Commission appreciates this opportunity to provide an update to the General Assembly on the Commission's implementation of the Regulation Act including the VCEA. The Commission has conducted numerous proceedings over the last year pursuant to the Regulation Act that are discussed in detail below. As a general matter, the Commission is seeing upward pressure on utility rates, not just for investor-owned electric utilities,[27] but across all regulated utilities. Factors contributing to increased utility costs include inflation, pandemic recovery, supply chain limitations, and high natural gas and other commodity prices, as well as geopolitical events. The Commission is keenly aware of the economic pressures that are impacting all utility customers and takes seriously its responsibility to review rate recovery requests. In each case, the Commission evaluates the request pursuant to the applicable laws, as well as the findings of fact supported by the evidence in the record.

The Commission continues to implement the VCEA in a manner that faithfully applies the requirements that include carbon reduction, while best protecting consumers who expect and deserve reliable and affordable service. Since the effective date of the VCEA, the Commission has approved DEV's requests for approval of 1,355 MW of new solar facilities (DEV-owned and PPA) and 103 MW of new energy storage capacity under the VCEA.[28] The Commission also recently issued an order approving cost

[27] DEV's most recent fuel factor filing, for example, showed a projected fuel deferral balance over the July 2021-June 2022 period of approximately $1 billion, due to increases in commodity prices over the past year. *Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.*6, Case No. PUR-2022-00064, Application at 2 (filed May 5, 2022).

[28] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing 2020 RPS Proceeding for Virginia Electric and Power Company*, Case No. PUR-2020-00134, 2021 S.C.C. Ann.

recovery associated with DEV's 2,587 MW CVOW Project, which is discussed in more detail below. For APCo, the Commission has approved 498 MW of new renewable generation supply since the passage of the VCEA.[29]

The Commission also concluded the first triennial review of DEV, approving the statutory maximum annual rate reduction of $50 million effective January 1, 2022, and customer refunds totaling $330 million over the 2022-2023 period, which is discussed in further detail below.

As detailed in Section V below, in addition to reviewing individual utility applications, the Commission has also sponsored and contributed to several stakeholder processes related to various aspects of utility regulation. Among those, as directed by House Bill 2282,[30] the Commission conducted a stakeholder process in the fall of 2021 focused on the transportation electrification with over 60 different organization participating in these meetings. On April 29, 2022, the Commission submitted a report to the General Assembly regarding policy proposals governing public electric utility programs to accelerate widespread transportation electrification in the Commonwealth,

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Rept. 242, 243, Final Order (April 30, 2021) (approving 498 MW of new solar facilities); *Petition of Virginia Electric and Power Company, For approval of the RPS Development Plan, approval and certification of the proposed CE-2 Solar Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under § 56-585.1 A 6 of the Code of Virginia, and a prudence determination to enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia*, Case No. PUR-2021-00146, Doc. Con. Cen. No. 220320113, Final Order at 6 (March 15, 2022) (approving 857 MW of new solar generation capacity and 103 MW of energy storage capacity).

[29] *Petition of Appalachian Power Company, For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia and related requests*, Case No. PUR-2021-00206, Doc. Con. Cen. No. 220720045, Final Order on Petition and Associated Requests, and Order Bifurcating Proceeding (July 15, 2022); *Petition* of A*ppalachian Power Company, For a prudency review, pursuant to § 56-585.1:4 H of the Code o*f *Virginia, with respect to the purchase of the Amherst Solar Facility*, Case No. PUR-2021-00066, Doc. Con. Cen. No. 220230049, Final Order (February 18, 2022).

[30] 2021 Va. Acts ch. 268 (Special Session 1).

noting that the increased deployment of motor vehicles powered by electricity presents several issues that potentially could affect the affordability and reliability of electricity service delivered to consumers by regulated utilities.[31] Consistent with the recommendations of the stakeholder report, the Commission subsequently issued an Order that required DEV and APCo to file transportation electrification plans on or before May 1, 2023.[32]

Pandemic-related Activities

The Commission has previously reported on its response to the public health concern related to the spread of the coronavirus, or COVID-19. As noted in the 2021 Report, through several orders, the Commission directed regulated electric, natural gas, and water and sewer companies in Virginia to suspend service disconnections through October 5, 2020, affording the General Assembly and the Governor time to address the economic impact on utility customers legislatively.[33] Thereafter, the General Assembly in a November 2020 Special Session enacted budget legislation further prohibiting utility shut-offs during the then state of emergency declared by the Governor, subject to certain

[31] House Doc. No. 8, Report: Policy Proposals Governing Public Electric Utility Programs to Accelerate Widespread Transportation Electrification in the Commonwealth Pursuant to Chapter 268 of the 2021 Virginia Acts of Assembly (Special Session I) (HB 2282) (April 29, 2022). https://rga.lis.virginia.gov/Published/2022/HD8/PDF

[32] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Electrification of Motor Vehicles*, Case No. PUR-2020-00051, Doc. Con. Cen. No. 220630077, Order Directing the Filing of Transportation Electrification Plans (June 15, 2022).

[33] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Temporary Suspension of Tariff Requirements*, Case No. PUR-2020-00048, 2020 S.C.C. Ann. Rept. 467, Order Suspending Disconnection of Service and Suspending Tariff Provisions Regarding Utility Disconnections of Service (March 16, 2020); 2020 S.C.C. Ann. Rept. 467, Order Extending Suspension of Service Disconnections (April 9, 2020); 2020 S.C.C. Ann. Rept. 469, Order on Suspension of Service Disconnections (June 12, 2020); 2020 S.C.C. Ann. Rept. 473, Order on Moratorium (August 24, 2020); 2020 S.C.C. Ann. Rept. 475, Additional Order on Moratorium (September 15, 2020).

conditions and limitations.[34] This budget legislation also directed the Commission to distribute $100 million of Virginia's portion of coronavirus relief funds ("CRF") received under Public Law 116-136: Coronavirus Aid, Relief, and Economic Security Act, to electric, natural gas, and water and sewer utilities, including municipal utilities, throughout the Commonwealth to offset utility customer billing arrearages due to COVID-19.[35] Relatedly, budget legislation enacted by the General Assembly during a 2021 Special Session directed the Commission, in coordination with the Department of Housing and Community Development, to distribute $120 million of additional coronavirus relief funds received by Virginia under Public Law 117-2: American Rescue Plan Act of 2021 ("ARPA").[36] These funds were also distributed to Virginia's utilities (as identified above) to offset utility customer billing arrearages due to COVID-19. The Commission and its Staff continue to provide oversight of these CRF and ARPA distributions. Additionally, and at the General Assembly's direction, the Commission since 2020 has submitted annual reports to the General Assembly and the Executive Branch detailing current utility customer billing arrearages and utility service disconnections.[37] The annual submission of these reports will continue through 2023.

Composition of the Electric Industry in Virginia

The Commission's responsibilities include regulating a diverse electric industry pursuant to the Virginia Constitution and the laws enacted by the General Assembly.

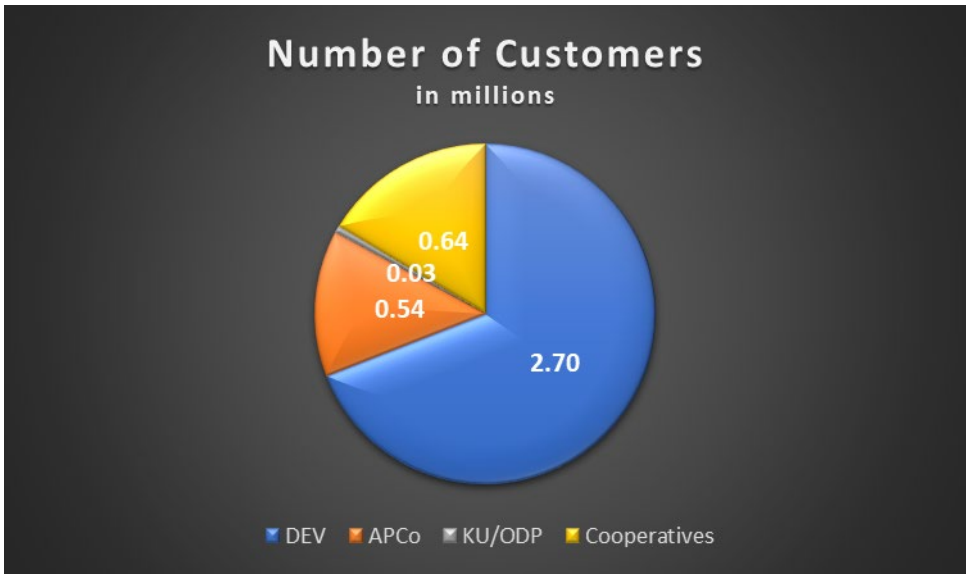
[34] *See*, House Bill 5005, 2020 Va. Acts, Special Session I, ch. 56 (Item 4-14)

[35] *See*, House Bill 5005, 2020 Va. Acts, Special Session I, ch. 56 (Item 479.10). *See also*, House Bill 1800, 2021 Va. Acts, Special Session I, ch. 552 (modifying pertinent provisions in Item 479.10).

[36] *See*, House Bill 7001, 2021 Va. Acts, Special Session II, ch. 1 (Item 479.20).

[37] *See*, House Bill 5005, 2020 Va. Acts, Special Session I, ch. 56 (Item 4-14)

Virginia's electric industry, for which the Commission regulates the rates and services to customers, consists of three investor-owned utilities and 13 member-owned electric cooperatives.[38] The number of Virginia jurisdictional customers by utility is shown below:[39]



II.
RATE AND CAPITAL OUTLOOK

DEV Typical Residential Bill

Below is a chart that reflects the magnitude of the three financial components of DEV customer bills as of the effective dates of the Regulation Act (July 1, 2007),[40] the Transitional Rate Period (July 1, 2015),[41] the Grid Transformation and Security Act

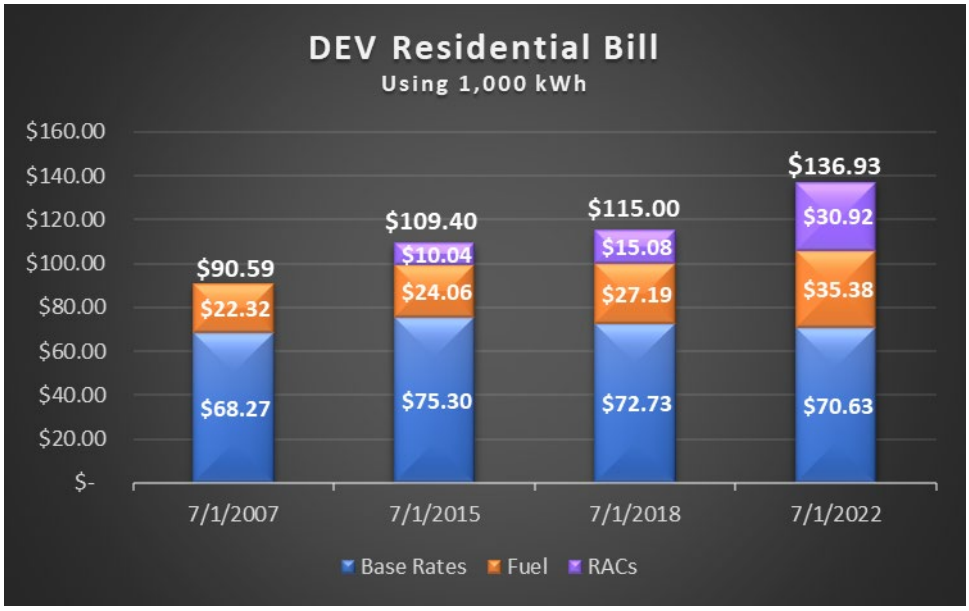
[38] Non-jurisdictional utilities, such as municipal electric utilities, also provide service in Virginia.

[39] Total Virginia customer numbers were reported in Federal Energy Regulatory Commission ("FERC") Form 1 and Annual Operating Reports.

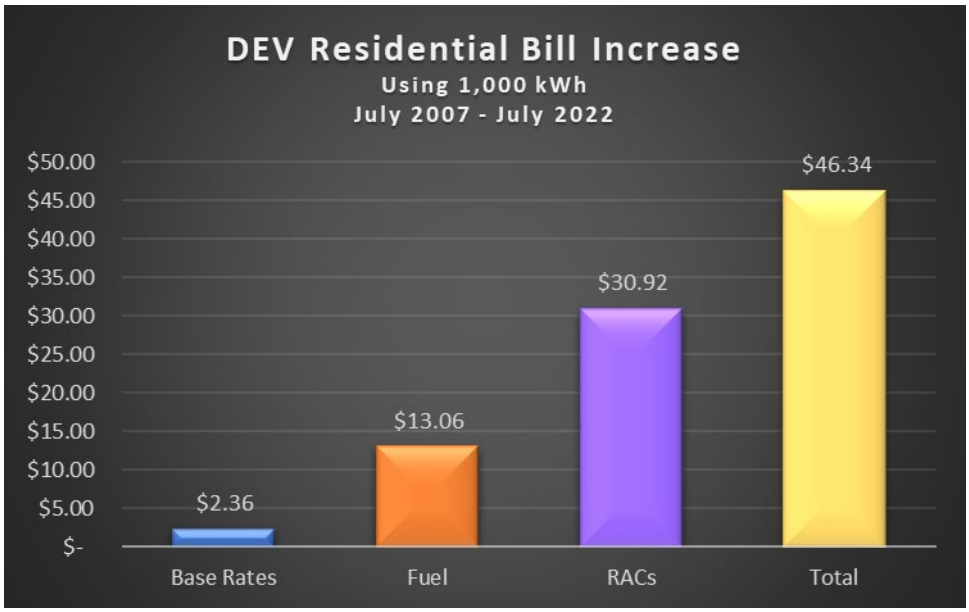
[40] 2007 Va. Acts. chs. 888 and 933.

[41] *See* Code § 56-585.1:1 for the specific transitional rate periods for Dominion and APCo. Both utilities were in their transitional rate periods on July 1, 2015.

("GTSA") (July 1, 2018), and the current year (July 1, 2022) for a typical residential customer using 1,000 kWh per month.



As the chart above indicates, DEV's monthly residential bill was $90.59 as of July 1, 2007. The bill has increased by $46.34 (51.15%) to $136.93 per month as of July 1, 2022. As reflected on the chart below, the RAC component of the bill experienced the largest increase over this period.


DEV Residential Bill Increase
Using 1,000 kWh
July 2007 - July 2022
$50.00
$45.00
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$-
$2.36
$13.06
$30.92
$46.34
Base Rates
Fuel
RACs
Total

The following chart itemizes a typical residential customer's bill by rate recovery mechanism as of July 1, 2022.

DEV Electric Utility Bills
As of July 1, 2022

Recovery Mechanism	Description	Current Residential Bill	Proposed Increase if Pending	Proposed Bill	Requested Effective Date
Base Rates	Base	$ 70.63	$ -	$ 70.63	-
Fuel Factor	Fuel	$ 35.38	$ -	$ 35.38	7/1/22*
Rider T1	Transmission	$ 6.90	$ (3.69)	$ 3.21	9/1/22
Rider R	Bear Garden Gas CC	$ 1.14	$ -	$ 1.14	-
Rider W	Warren Gas CC	$ 2.34	$ (0.38)	$ 1.96	4/1/23
Rider BW	Brunswick Gas CC	$ 2.10	$ 0.70	$ 2.80	9/1/22
Rider GV	Greensville Gas CC	$ 2.75	$ -	$ 2.75	-
Rider S	VCHEC	$ 3.70	$ -	$ 3.70	-
Rider B	Biomass	$ 0.30	$ 0.33	$ 0.63	4/1/23
Rider US-2	Solar	$ 0.17	$ 0.05	$ 0.22	9/1/22
Rider US-3	Solar	$ 0.96	$ -	$ 0.96	-
Rider US-4	Solar	$ 0.30	$ -	$ 0.30	-
Rider CE	Solar	$ 1.32	$ 1.13	$ 2.45	-
Rider SNA	Nuclear Relicensing	$ -	$ 2.11	$ 2.11	9/1/22
Rider RPS	RECs	$ 0.18	$ 1.64	$ 1.82	9/1/22
Rider RGGI	RGGI	$ -	$ -	$ -	7/1/22**
Rider OSW	Offshore Wind	$ -	$ 1.45	$ 1.45	9/1/22
Rider PPA	Renewable PPAs	$ -	$ (0.07)	$ (0.07)	9/1/22
Riders C1A/C2A/etc.	Energy Efficiency	$ 1.31	$ 0.29	$ 1.60	9/1/22
Rider U	Strategic Undergrounding	$ 2.50	$ (0.51)	$ 1.99	4/1/23
Rider GT	Grid Transformation	$ 1.16	$ -	$ 1.16	-
Rider E	Coal Ash	$ 1.25	$ 0.70	$ 1.95	9/1/22
Rider CCR	Coal Ash	$ 2.95	$ 0.01	$ 2.96	12/1/22
Rider RBB	Rural Broadband	$ 0.03	$ 0.14	$ 0.17	12/1/22
PIPP USF***	PIPP	$ 0.03	$ -	$ 0.03	-
Rider VCR****	Voluntary Credit Rider	$ (0.47)	$ -	$ (0.47)	
Total		**$ 136.93**	**$ 3.90**	**$ 140.83**	

*The fuel factor rate was implemented on an interim basis on 7/1/22, subject to modification.

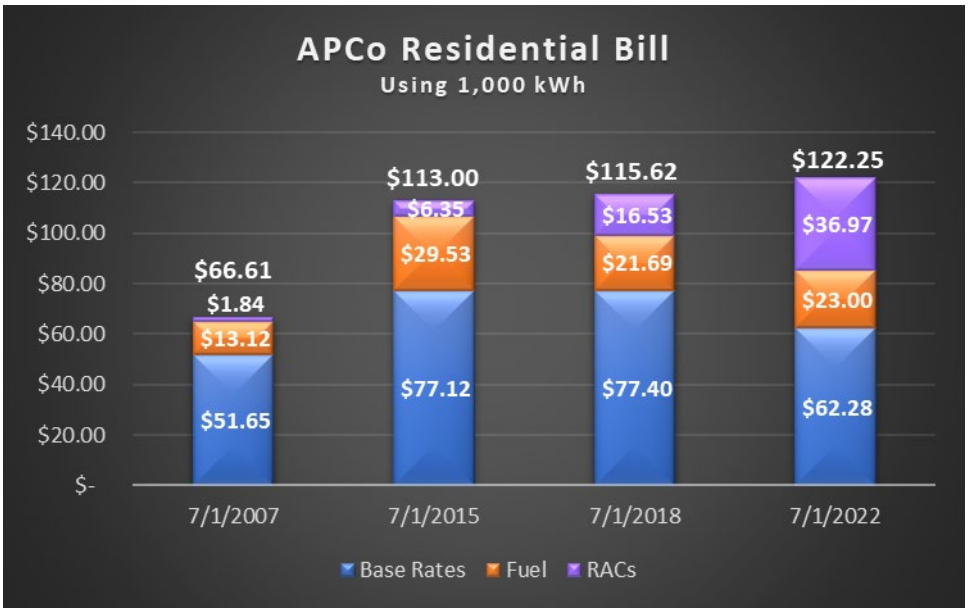
**The Commission granted DEV's petition to reset Rider RGGI to zero and recover the unrecovered RGGI compliance costs through base rates.

***Current PIPP collections are designed to fund the estimated start-up costs of DSS needed to establish the PIPP. The PIPP will commence no later than one year after DSS publishes guidelines for the adoption, implementation, and general administration of the PIPP and Percentage of Income Payment Fund.

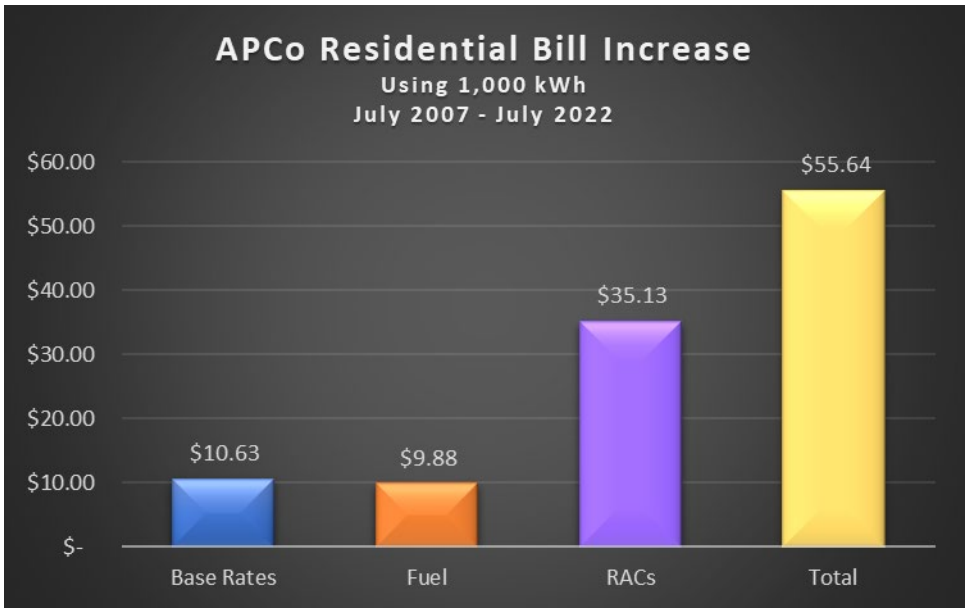
****Rider VCR provides bill credits to customers pursuant to the stipulation in DEV's 2021 triennial review.

APCo Typical Residential Bill

Below is a chart that reflects the magnitude of the three financial components of APCo customer bills as of the effective dates of the Regulation Act (July 1, 2007), the Transitional Rate Period (July 1, 2015), the GTSA (July 1, 2018), and the current year (July 1, 2022) for a typical residential customer using 1,000 kWh per month.



As the chart indicates, APCo's monthly residential bill was $66.61 as of July 1, 2007. The bill has increased by $55.64 (83.53%) to $122.25 per month as of July 1, 2022. As reflected on the chart below, the RAC component of the bill experienced the largest increase over this period.


APCo Residential Bill Increase
Using 1,000 kWh
July 2007 - July 2022
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
$10.63
$9.88
$35.13
$55.64
Base Rates
Fuel
RACs
Total

The following chart itemizes a typical residential customer's bill by rate recovery mechanism as of July 1, 2022.[42]

APCo Electric Utility Bills
As of July 1, 2022

Recovery Mechanism	Description	Current Residential Bill	Proposed Increase if Pending	Proposed Bill	Requested Effective Date
Base Rates	Base	$ 65.40	$ -	$ 65.40	-
Fuel Factor	Fuel	$ 23.00	$ -	$ 23.00	-
TRR Rider Credit	Tax Reform	$ (3.12)	$ -	$ (3.12)	-
PIPP USF	PIPP*	$ 0.04	$ -	$ 0.04	-
T-RAC	Transmission	$ 31.55	$ 2.88	$ 34.43	8/1/22
G-RAC	Dresden Gas CC	$ 2.55	$ -	$ 2.55	-
EE-RAC	Energy Efficiency	$ 1.12	$ 0.34	$ 1.46	9/1/22
DR-RAC	Demand Response	$ 0.22	$ -	$ 0.22	-
E-RAC	Coal Ash	$ 2.11	$ 0.80	$ 2.91	12/1/22
BC-RAC	Rural Broadband	$ 0.54	$ (0.69)	$ (0.15)	2/1/23
RPS-RAC (legacy)	Voluntary RPS	$ (1.16)	$ -	$ (1.16)	-
RPS-RAC (new)	Mandatory RPS	$ -	$ 2.37	$ 2.37	8/1/22
Total		$ 122.25	$ 5.70	$ 127.95	

*Current PIPP collections are designed to fund the estimated start-up costs of DSS needed to establish the PIPP. The PIPP will commence no later than one year after DSS publishes guidelines for the adoption, implementation, and general administration of the PIPP and Percentage of Income Payment Fund.

Rate and Capital Outlook

2021 RPS Plans

On September 15, 2021, DEV submitted its petition for approval of its 2021 RPS Plan to develop new solar and onshore wind generation capacity and energy storage as required by the VCEA pursuant to Code § 56-585.5 D 4. Among other things, DEV's 2021 RPS Plan calls for 3,105 MW of solar and onshore wind development through 2024 and the development of 331 MW of energy storage resources through 2025.[43] DEV

[42] The TRR Rider Credit is a temporary base rate rider credit to return to customers the impacts of the 2018 Tax Cuts and Jobs Act.

[43] *Petition of Virginia Electric and Power Company, For approval of its 2021 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia and related requests,* Case No. PUR-2021-00146, Doc. Con.

estimates that by 2045, it may have 18,356 MW (nameplate) of solar resources, 5,174 MW (nameplate) of offshore wind resources, and 316 MW (nameplate) of hydroelectric resources that it will use toward meeting its capacity obligations in PJM, in addition to 2,580 MW (nameplate) of energy storage.[44]

The Commission issued a Final Order on March 15, 2022, wherein it: (i) found DEV's RPS Plan was reasonable and prudent for the limited purpose of its second annual plan; (ii) approved approximately 857 MW of new solar generation capacity in the Commonwealth including both company-owned resources and PPAs; (iii) approved 103 MW of energy storage capacity; and (iv) approved a RAC for cost recovery associated with approved company-owned solar facilities.[45] The Commission also established additional directives regarding DEV's modeling in its subsequent RPS Plans.[46] The Commission further directed DEV to continue filing a consolidated bill analysis in its IRP and RPS Plan proceedings with information through 2035.[47] DEV has filed a notice of intent to file its 2022 RPS Plan on or after September 15, 2022.

On December 30, 2021, APCo submitted its 2021 RPS Plan to develop new solar and onshore wind generation capacity required by the VCEA. Among other things,

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Cen. No. 210930080, RPS Plan at 4, 7 (filed September 15, 2021). For additional information on renewable deployment, on or before December 1 of each year, the Commission files an annual report to the General Assembly on the construction of new solar and wind projects pursuant to Enactment Clause 14 of the GTSA, as amended by 2020 Va. Acts ch. 1190.

[44] *Id*. at 14.

[45] *Petition of Virginia Electric and Power Company, For approval of its 2021 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia and related requests,* Case No. PUR-2021-00146, Doc. Con. Cen. No. 220320113, Final Order (March 15, 2022).

[46] *See, e.g., id.* at 8-10.

[47] *Id.* at 11.

APCo's 2021 RPS Plan calls for approximately 553 MW of solar and onshore wind development through 2025, including resources that became operational in 2021 and resources expected to become operational by the end of 2022.[48] APCo anticipates adding storage resources beginning in 2025.[49] APCo estimates that by 2040, it may have 2,736 MW (nameplate) of solar, 750 MW (nameplate) of onshore wind, and 2,937 MW (nameplate) of energy storage, through a mix of company-owned resources and PPAs, to meet the requirements of the VCEA.[50]

On July 15, 2022, the Commission issued a Final Order on APCo's 2021 RPS Plan, wherein the Commission: (i) found APCo's RPS Development Plan is reasonable and prudent for the limited purpose of its second annual plan; (ii) approved APCo's requests for approval of cost recovery for 313.9 MW of solar and onshore wind capacity, including both company-owned resources and PPAs; (iii) granted APCo's request for a prudency determination for 238.9 MW of solar capacity, including company-owned resources and PPAs; (iv) approved the recovery of projected costs of RECs purchased in the PJM REC market; and (v) approved RACs for cost recovery.[51] The Commission also established additional directives regarding APCo's modeling in its subsequent RPS

[48] *Petition of Appalachian Power Company, For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia,* Case No. PUR-2021-00206, RPS Plan at 7 (filed December 30, 2021).

[49] *Id.* at 8, 37.

[50] *Id.* at 40.

[51] *Petition of Appalachian Power Company, For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia and related requests*, Case No. PUR-2021-00206, Doc. Con. Cen. No. 220720045, Final Order on Petition and Associated Requests, and Order Bifurcating Proceeding (July 15, 2022).

Plans.[52] The Commission further directed APCo to continue filing a consolidated bill analysis in its RPS Filings.[53]

The Commission also found that a separate proceeding should be established to further consider the appropriate cost recovery framework for APCo's VCEA-related resources, the allocation of costs net of benefits pursuant to Code § 56-585.5 F, and class and jurisdictional cost allocation.[54] The Commission directed APCo to make a filing addressing these issues on or before October 1, 2022.[55]

DEV Offshore Wind

On August 5, 2022, the Commission issued a Final Order on DEV's application for cost recovery associated with its proposed CVOW Project.[56] The project consists of 176 wind turbines, each designed to generate 14.7 MW, to be located approximately 27 miles off the coast of Virginia Beach. The project is expected to have a capital cost of $9.8 billion and will likely be the largest capital investment, and single largest project, in the history of Dominion Energy Virginia.[57]

The Commission approved a revenue requirement of $78.702 million for the rate year of September 1, 2022, to August 31, 2023, to be recovered through a new rate

[52] *See, e.g., id.* at 6-7.

[53] *Id.* at 8.

[54] *See id.* at 13-15.

[55] *Id.* at 17.

[56] *Application of Virginia Electric and Power Company, For approval and certification of the Coastal Virginia Offshore Wind Commercial Project and Rider Offshore Wind, pursuant to § 56-585.1:11, § 56-46.1, § 56-265.1 et seq. and § 56-585.1 A 6 of the Code of Virginia,* Case No. PUR-2021-00142, Doc. Con. Cen. No. 220820117, Final Order (August 5, 2022).

[57] *Id.* at 5-6.

adjustment clause, designated Rider OSW.[58] Over the projected 35-year lifetime of the project, for a residential customer using 1,000 kWh of electricity per month, Rider OSW is projected to result in an average monthly bill increase of $4.72 and a peak monthly bill increase of $14.22 in 2027.[59]

The Commission recognized that significant concerns were raised throughout the proceeding regarding the affordability of the project and the financial risk to ratepayers. With a project of this magnitude, the Commission ordered the following consumer protections:[60]

- Dominion shall file a notice with the Commission within 30 calendar days if it determines that the total project costs are expected to exceed the current estimate, or if the final turbine installation is expected to be delayed beyond February 4, 2027.
- Each annual Rider OSW update application filed by Dominion prior to the project's commercial operation shall include any material changes to the project, the most recent biannual project update, and a written explanation as to the reason for any cost overruns above the most recent estimate provided by the company to include the reasonableness and prudence of the additional costs.
- Beginning with the commercial operation and extending for the life of the project, customers shall be held harmless for any shortfall in energy production below an annual net capacity factor of 42 percent, as measured on a three-year rolling average ("Performance Standard").

In a concurring opinion, Commissioner Jagdmann wrote that she agrees with the Final Order in all respects. She emphasized that these aforementioned protections do not completely address potential Project abandonment risks, stating:

> [i]mportantly, the General Assembly has effectively maintained its ability to implement additional protections – for example through funding mechanisms such as general

[58] *Id.* at 11-12.

[59] *Id.* at 5.

[60] *Id.* at 14-16.

> fund appropriation or other means, such as implementing new legislation designating the consumer-funded proceeds from Dominion's participation in the Regional Greenhouse Gas Initiative ("RGGI") be used to lessen the cost of the CVOW Project.... Such action may be appropriate given the public policy support for and economic development aspects of this Project.[61]

On August 22, 2022, DEV filed a Petition for Limited Reconsideration of the Commission's decision requesting the Commission reconsider the Performance Standard. Among other things, Dominion states that "[a]s ordered, [the performance standard] will prevent the Project from moving forward, and the Company will be forced to terminate all development and construction activities."[62] On August 24, 2022, the Commission issued an order granting reconsideration for purposes of continuing jurisdiction over the case and directed the filing of responses to DEV's request for reconsideration. On August 25, 2022, Consumer Counsel filed a Petition for Clarification or Reconsideration related to the Performance Standard.[63]

Nuclear License Extensions

The Commission approved DEV's petition for approval of a RAC, designed Rider SNA, for cost recovery associated with preparing Petitions for Subsequent License Renewal to the Nuclear Regulatory Commission to extend the operating license of, and

[61] *Id.* at 41-42.

[62] *Application of Virginia Electric and Power Company, For approval and certification of the Coastal Virginia Offshore Wind Commercial Project and Rider Offshore Wind, pursuant to § 56-585.1:11, § 56-46.1, § 56-265.1 et seq. and § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00142, Petition of Virginia Electric and Power Company for Limited Reconsideration at 3 (filed August 22, 2022).

[63] *Application of Virginia Electric and Power Company, For approval and certification of the Coastal Virginia Offshore Wind Commercial Project and Rider Offshore Wind, pursuant to § 56-585.1:11, § 56-46.1, § 56-265.1 et seq. and § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00142, Petition for Clarification or Reconsideration of Office of the Attorney General, Division of Consumer Counsel (filed August 25, 2022).

the projects reasonably appropriate to upgrade or replace systems and equipment deemed to be necessary to extend the life of, Dominion's Surry Units 1 and 2 and North Anna Units 1 and 2 nuclear generation facilities from 60 to 80 years.[64] The approved revenue requirement for the initial rate year of Rider SNA commencing September 1, 2022, is $106.664 million.[65]

Grid Transformation Plan

The Commission issued a Final Order concerning its review of DEV's petition for approval of Phase II of its GT Plan.[66] The approved GT Plan investments focus on grid reliability and are designed to accommodate or facilitate the expected increase in distributed energy resources resulting from recent policy developments, including the VCEA and FERC Order 2222. Approved Phase II investments include (i) advanced metering infrastructure; (ii) the customer information platform; (iii) grid infrastructure, which comprises targeted corridor improvement and voltage island mitigation; (iv) grid technologies; (v) telecommunications; (vi) cyber security; (vii) physical security; and (viii) customer education. The projected capital and operations expenses for Phase II are projected to be approximately $776 million. The Commission's approval of these projects was made subject to certain contingencies, cost caps, and reporting requirements.

APCo did not file a grid transformation plan in 2021.

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[64] *Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider SNA under § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00229, Doc. Con. Cen. No. 220710001, Final Order (July 1, 2022).

[65] *Id.* at 6.

[66] *Petition of Virginia Electric and Power Company, For approval of a plan for electric grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00127, Doc. Con. Cen. No. 22010126, Final Order (January 7, 2022).

Integrated Resource Plans

DEV did not file an IRP in 2021.[67] In accordance with Code § 56-599, DEV's next IRP will be due by May 1, 2023. In DEV's most recent prior IRP, the Commission directed DEV's future IRPs to include actual bill impact information as each year passes.[68] Further, the Commission found that DEV should address environmental justice in future IRPs and updates, as appropriate.[69]

APCo did not file a 2021 IRP. It filed its 2022 IRP on April 29, 2022. Based on APCo's billing analysis, showing projected annual impacts to a residential bill over the next five years incorporating the requirements of the VCEA, the monthly bill of a Virginia residential customer using 1,000 kWh per month is projected to be between $141.73 and $143.07 by 2026, an increase of between $19.50 and $20.84 per month over the April 29, 2022 typical residential bill (or an estimated annual increase of $234.00 to $250.08).[70] APCo's 2022 IRP is pending before the Commission and an evidentiary hearing is scheduled to begin on October 25, 2022.[71]

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[67] DEV filed an update to its 2020 IRP, which was accepted for filing by the Commission. *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's 2021 Update to its Integrated Resource Plan pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2021-00201, 2021 S.C.C. Ann. Rept. 544, Final Order (October 28, 2021).

[68] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2020-00035, 2021 S.C.C. Ann. Rept. 190, 195-196, Final Order (February 1, 2021). The Commission further directed that in addition to residential bills, the Company should include a billing analysis of small general service and large general service customer bills. *Id.* at 196.

[69] *Id*. at 195.

[70] The projected monthly bill increases of $19.50 and $20.84 are based on the 2022 IRP Least Cost Plan and Hybrid Plan, respectively.

[71] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2022-00051, Doc. Con. Cen. No. 220540021, Order for Notice and Hearing (May 24, 2022).

2022 Investor Presentations

DEI presented its fourth quarter earnings to investors on February 11, 2022.[72] [73] This February 2022 presentation to investors identified approximately $27.9 billion in anticipated growth capital expenditures for DEV over the period 2022 – 2026.[74] DEI identified the primary drivers as zero-carbon generation and storage, transmission, and customer growth, as outlined in the chart below.

February 11, 2022 Investor Presentation
DEV Identified Capital Investment
Five Year Outlook 2022 through 2026

	Growth Capex 2022 - 2026
Offshore Wind	$10 Billion
Solar	$6.8 Billion
Transmission	$4 Billion
Customer Growth	$2 Billion
Nuclear Relicensing	$2 Billion
Grid Transformation	$1.5 Billion
Strategic Undergrounding	$1 Billion
Energy Storage	$0.6 Billion
Total Growth Capex	$27.9 Billion

[72] Slides for the February 11, 2022 presentation ("Fourth Quarter Presentation Slides") are available at: https://s2.q4cdn.com/510812146/files/doc_financials/2021/q4/2022-02-11-DE-IR-4Q-2021-earnings-call-slides-vTCIII.pdf. DEI is the parent company of DEV.

[73] DEI also gave an investor presentation on May 5, 2022, for the first quarter of 2022, and August 5, 2022, for the second quarter of 2022. These presentations did not include the same level of DEV-specific capital investment information as the 2021 fourth quarter presentation. Slides for the May 5, 2022, presentation are available at: https://s2.q4cdn.com/510812146/files/doc_financials/2022/q1/2022-05-05-DE-IR-1Q-2022-earnings-call-slides-vTCI_Final.pdf. Slides for the August 5, 2022 presentation are available at https://s2.q4cdn.com/510812146/files/doc_presentations/2022/08/2022-08-08-DE-IR-2Q-2022-earnings-call-slides-vTC.pdf.

[74] *See* Fourth Quarter Presentation Slides 47-49.

In its February 2022 presentation to investors, DEI estimated that by 2026, 92% of the $27.9 billion of growth capex would be eligible to be recovered through RACs.[75] As a result, by 2026, DEI projected that a total of 55% of DEV's $50.7 billion net rate base would be eligible to be recovered through RACs.[76] DEV's projected $50.7 billion net rate base in 2026 would reflect an increase of 74% when compared to 2021. As with the Commission's 2021 report, the totality of these projected capital investments reflect DEI's presentation to investors and have not been independently reviewed by Commission Staff or as part of a Commission proceeding.

[75] *See* Fourth Quarter Presentation Slide 47.

[76] *See* Fourth Quarter Presentation Slide 51.

III.
BASE RATE FINANCIAL RESULTS

DEV 2017-2020 Triennial Review

On March 31, 2021, DEV filed its application for the 2021 triennial review provided for by Code § 56-585.1 A, docketed as Case No. PUR-2021-00058.[77] As filed, DEV presented a combined generation and distribution base rate earned ROE of 9.61%[78] for the combined test periods of 2017 through 2020, which is within the 70 basis point band above and below the 9.20% ROE approved by the Commission in Case No. PUR-2019-00050 to be used to measure earnings in DEV's first triennial review.[79] DEV's earned return was driven in large part by the impairment of the unrecovered balances of several generating units it had retired in 2019 and 2020, which it treated as a period expense subject to the provisions of Code § 56-585.1 A 8.

The evidentiary hearing for the case was held on October 25, 2021. On November 18, 2021, the Commission issued its Final Order in DEV's triennial review.[80]

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[77] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution, and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUR-2021-00058, Doc. Con. Cen. No. 210340128, Application (filed March 31, 2021), *amended by* Doc. Con. Cen. No. 210530106, Amended Application (May 18, 2021) (including an amended application, supplemental testimony and filing schedules reflecting a revision to its earned return in the combined earnings test analysis).

[78] This ROE includes the earnings reduction resulting from $206 million of customer accounts receivable written off pursuant to House Bill 5005, 2020 Va. Acts, Special Session I, ch. 56, and House Bill 1800, 2021 Va. Acts, Special Session I, ch. 552. The earned ROE was 10.42% excluding this write-off.

[79] *Application of Virginia Electric and Power Company, For the determination of the fair rate of return on common equity pursuant to § 56-585.1:1 C of the Code of Virginia*, Case No. PUR-2019-00050, 2019 S.C.C. Ann. Rept. 400, Final Order (November 21, 2019).

[80] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

The Commission approved a stipulation proposed by the majority of case participants, and which was unopposed by any party to the case. In so doing, the Commission approved customer refunds totaling $330 million, the statutory maximum annual rate reduction of $50 million,[81] and customer credit reinvestment offsets of $309 million. For a typical residential customer, this results in a decrease of approximately $0.90 per month effective January 1, 2022, and refunds totaling approximately $67.00 over the 2022-2023 period.

The Commission also approved a 9.35% ROE as fair and reasonable for the 2021 – 2023 period that will be the subject of DEV's next triennial review.[82]

APCo 2017-2019 Triennial Review

As the Commission previously reported, on November 24, 2020, the Commission issued its Final Order in APCo's 2017-2019 triennial review, finding APCo earned an ROE of 9.48% for the 2017 – 2019 triennial period.[83] APCo and Consumer Counsel both filed notices of appeal of the Commission's decision to the Supreme Court of Virginia. On August 18, 2022, the Court issued its opinion affirming in part, reversing in part, and remanding the case to the Commission for further proceedings consistent with the Court's opinion.[84] On remand, the Commission will recalculate APCo's earned ROE for the

[81] Code § 56-585.1 A 8 c.

[82] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

[83] *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, 2020 S.C.C. Ann. Rept. 421, Final Order (November 24, 2020).

[84] *Appalachian Power Co. v. State Corp. Comm'n*, Record No. 210391 (Va. Aug. 18, 2022).

2017-2019 triennial period and determine whether APCo is entitled to a rate increase effective January 1, 2021, and by what amount, based on the Court's findings in its opinion. On August 22, 2022, the Commission issued an Order Initiating Remand Proceedings directing APCo to file interim rates for (a) base rates going forward, and (b) a rider designed to collect revenues not collected from January 1, 2021, through September 30, 2022, to be implemented October 1, 2022.[85]

APCo will file its next triennial review application on or before March 31, 2023, which will cover the period 2020-2022.

DEV 2021 Base Rate Financial Results

During 2022, in response to requests from Staff pursuant to Code § 56-36, DEV provided certain analyses of its combined generation and distribution base rate financial results for calendar year 2021 on a regulatory accounting basis. Calendar year 2021 is the first year of DEV's second triennial review, which will be filed with the Commission in 2024 and will cover the period 2021 – 2023.

DEV analysis reflects a combined base rate generation and distribution ROE of 11.49% for 2021.[86] [87]

[85] *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, Doc. Con. Cen. No. 220840166, Order Initiating Remand Proceedings (August 22, 2022).

[86] A 0.01 percentage point of ROE was worth approximately $709,000 in combined generation and distribution annual revenues for DEV in 2021 provided by its customers through payment of their electric bills.

[87] This 2021 earned ROE is based on information provided by DEV. The Commission did not conduct an audit or investigation of the financial information provided by DEV. The Commission will conduct an audit of DEV's 2021 earnings as part of its 2024 triennial review. Interested parties will have an opportunity to participate in that proceeding. The 2021 earned ROE determined by the Commission in the 2024 triennial review may differ from the information provided by DEV and included in this report.

DEV 2021 Earned Return on Equity

Generation	Distribution	Combined
19.39%	4.49%	11.49%

DEV's reported 2021 combined generation and distribution unaudited earned ROE is above the 9.35% base ROE approved by the Commission in Case No. PUR-2021-00058 to be used for the 2021 – 2023 period. The following table provides a breakdown of DEV's 2021 earnings in both percentage points and revenues:

DEV 2021 Earnings in Excess of or Below a 9.35% ROE
(Revenues in Millions of Dollars)

	Generation	Distribution	Combined
Percentage Points	10.04%	-4.86%	2.14%
Revenues	$334.8	-$182.7	$152.1

As discussed above, Code § 56-585.1 A 8, as amended by the GTSA, states that certain costs are deemed fully recovered in the test period in which they were recorded per books by the company for financial reporting purposes. DEV stated it recorded costs in base rates related to severe weather events of $45.5 million during 2021 that are subject to Code § 56-585.1 A 8. DEV also recorded costs in base rates related to coal combustion residual management of $3.0 million during 2021 subject to Code § 56-585.1 A 8. These costs reduced DEV's reported 2021 earned ROE by 0.64 and 0.04 percentage points, respectively.

DEV did not defer any COVID-19-related expenses in 2021.

APCo 2021 Base Rate Financial Results

During 2022, in response to requests from Staff pursuant to Code § 56-36, APCo provided certain analyses of its combined generation and distribution base rate financial results for calendar year 2021 on a regulatory accounting basis. Calendar year 2021 is the second year of APCo's second triennial review, which will be filed with the Commission in 2023 and will cover the period 2020 – 2022.

APCo's analysis reflects a combined base rate generation and distribution ROE of 5.38% for 2021.[88] [89]

APCo 2021 Earned Return on Equity

Generation	Distribution	Combined
11.16%	1.32%	5.38%

APCo's reported 2021 combined generation and distribution unaudited earned ROE is below the 9.20% base ROE approved by the Commission in Case No. PUR-2020-00015 to be used for the 2020 – 2022 period. The following table provides a breakdown of APCo's 2021 earnings above or below the 9.20% approved ROE in both percentage points and revenues:

[88] A 0.01 percentage point of ROE was worth approximately $177,000 in combined generation and distribution annual revenues for APCo in 2021 provided by its customers through payment of their electric bills.

[89] This 2021 earned ROE is based on information provided by APCo. The Commission did not conduct an audit or investigation of the financial information provided by APCo. The Commission will conduct an audit of APCo's 2021 earnings as part of its 2023 triennial review. Interested parties will have an opportunity to participate in that proceeding. The 2021 earned ROE determined by the Commission in the 2023 triennial review may differ from the information provided by APCo and included in this report.

APCo 2021 Earned Return on Equity

(Revenue in Millions of Dollars)

	Generation	Distribution	Combined
Percentage Points Above/(Below) 9.20% ROE	1.96%	-7.88%	-3.82%
Revenue Sufficiency/(Deficiency)	16.2	(73.9)	(67.4)

Section 56-585.1 A 8 of the Code, as amended by the GTSA, directs the Commission to order increases to base rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn a fair combined rate of return if APCo's combined 2020-2022 earnings are more than 0.70 percentage points below the approved ROE of 9.20%.[90]

APCo Combined Earnings

(Earnings in Millions)

	2020	2021	Combined
Net Deficiency (From Bottom of the Range)	57.4	51.4	108.8

As discussed above, Code § 56-585.1 A 8, as amended by the GTSA, states that certain costs are deemed fully recovered in the test period in which they were recorded per books by the company for financial reporting purposes. To the extent those costs cause APCo's combined return to fall below the bottom of the 0.7 percentage point range, they may be deferred and amortized over a future period. APCo stated it recorded costs in base rates related to severe weather events of $11.7 million during 2021 that are subject to Code § 56-585.1 A 8. These costs reduced APCo's reported 2021 earned return by 0.05 percentage points.

[90] If the Commission finds, based on the evidence in the 2023 triennial review, APCo has a combined ROE more than 0.7 percentage points above the approved ROE, the Commission shall order refunds or consumer credit reinvestment offsets equal to the amount above the approved ROE plus 0.7 percentage points.

APCo also reported that it incurred and deferred $2.1 million in COVID-19-related expenses in 2021, which consisted primarily of bad debt expense and protective materials and supplies.

IV.

CURRENT STATUS OF PROCEEDINGS UNDER THE REGULATION ACT

The Regulation Act has undergone a number of amendments over the last few years resulting in numerous new programs, requirements, and rulemakings that apply to the Commonwealth's incumbent electric utilities and electric cooperatives. Since the Commission's 2021 Report, the Commission has conducted additional proceedings brought pursuant to the Regulation Act. This section provides a high-level summary of certain proceedings decided by the Commission since September 1, 2021, the date of the 2021 Report, or pending at the time of this report.[91]

Renewable Energy Cases

Below is a table summarizing the renewable energy cases decided by or pending with the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Regulations for a multi-family shared	Pending	§ 56-585.1:12	PUR-2020-00124

[91] Copies of the Commission's full orders, as well as access to publicly-filed case documents, are available at the Commission's website: https://scc.virginia.gov/pages/Case-Information, by clicking "Docket Search," and clicking "Search By Case Information," and entering the case number in the appropriate box.

	solar program			
DEV	Regulations for a shared solar program	Pending	§ 56-594.3	PUR-2020-00125
APCo	RPS-RAC	Resolved	§ 56-585.2 E	PUR-2021-00048
SCC	GATS Business Rules	Resolved	§ 56-585.5	PUR-2021-00064
APCo	Amherst Solar Facility	Resolved	§ 56-585.1:4 H	PUR-2021-00066
Axton Solar, LLC	Solar Project	Pending	§ 56-580 D	PUR-2021-00085
DEV, APCo	Accelerated Renewable Energy Buyers	Resolved	§ 56-585.5 G	PUR-2021-00089
DEV	US-3 Solar Projects (Update)	Resolved	§ 56-585.1 A 6	PUR-2021-00118
DEV	US-4 Solar Project (Update)	Resolved	§ 56-585.1 A 6	PUR-2021-00119
DEV	Rider TRG (Update)	Resolved	§ 56-577 A 5	PUR-2021-00138
DEV	Offshore wind generation facilities	Pending	§ 56-585.1:11, et al	PUR-2021-00142
DEV	2021 RPS Filing	Resolved	§ 56-585.5	PUR-2021-00146
DEV	Allocation of RPS-related costs	Pending	§ 56-585.5	PUR-2021-00156
APCo	2021 RPS Filing	Resolved	§ 56-585.5	PUR-2021-00206
DEV	Rider PPA	Resolved	§ 56-585.1 A 5	PUR-2021-00248

DEV	Rider RPS	Resolved	§ 56-585.1 A 5	PUR-2021-00282
SCC	GATS business rules; revisions	Pending	§ 56-585.5	PUR-2022-00045
DEV	GATS Business Rules; calculating RECs for a hybrid facility	Resolved	§ 56-585.5	PUR-2022-00075
DEV	Rider TRG (Update)	Pending	§ 56-577	PUR-2022-00101

Decisions

- APCO RPS RAC (PUR-2021-00048). The Commission approved APCo's application to revise its RPS-RAC to recover residual, incremental costs related to APCo's participation in its voluntary RPS program that was in place prior to the passage of the VCEA. (Final Order, December 6, 2021). §§ 56-585.1 A 5 d and 56-585.2 E of the Code.

- GATS Business Rules: Registration and retirement of Virginia-eligible renewable energy certificates (PUR-2021-00064). The Commission revised its business rules concerning the registration and retirement of Virginia-eligible RECs in the PJM-EIS Generation Attribute Tracking System ("GATS"). This revision followed the Commission's then-recent update to these rules to reflect the categories of eligible generation sources for Virginia-qualified RECs in 2021-2024 under Virginia's mandatory RPS statute (§ 56-585.5). This docket was established to invite comment on that update and resulted in further revisions to these business rules. (Final Order, September 30, 2021). § 56-585.5 C of the Code.

- APCo Amherst Solar Facility (PUR-2021-00066). The Commission approved a prudency determination for APCo's proposed 4.875 MW Amherst Solar Facility. APCo did not seek cost recovery for the facility in this case. (Final Order, February 18, 2022). § 56-585.1: 4 H of the Code.

- Rules related to Accelerated Renewable Energy Buyers (PUR-2021-00089). The Commission adopted regulations implementing the provisions of Code § 56-585.5 G, enacted as part of the VCEA. Section 56-585.5 G permits certain customers of APCo and DEV to be certified as accelerated renewable energy buyers, and to be exempted from some or all of the RPS costs of these utilities. (Final Order, December 10, 2021). § 56-585.5 G of the Code.

- DEV US-3 Solar Projects RAC (PUR-2021-00118). The Commission approved DEV's annual update to its RAC for cost recovery associated with its US-3 Solar Projects (the Colonial Trail West Solar Facility, an approximately 142 MW solar generating facility located in Surry County, Virginia, and the Spring Grove 1 Solar Facility, an approximately 98 MW solar facility located in Surry County, Virginia). (Final Order, March 24, 2022). § 56-585.1 A 6 of the Code.

- DEV US-4 Solar Project RAC (PUR-2021-00119). The Commission approved DEV's annual update to its US-4 RAC for cost recovery associated with its Sadler Solar Facility (an approximately 100 MW utility-scale solar photovoltaic generating facility located in Greensville County, Virginia). (Final Order, March 18, 2022). § 56-585.1 A 6 of the Code.

- DEV Rider TRG Update (PUR-2021-00138). The Commission reviewed DEV's annual update of its previously approved 100% renewable tariff, Rider TRG. The update was filed on July 1, 2021. The update requested no change to the approved rate or to the portfolio of renewable resources providing service under Rider TRG. Rider TRG limits the ability of customers in DEV's service territory to purchase renewable energy from competitive suppliers under Code § 56-577 A 5. The Commission exercised its discretion not to address participant levels, and not to modify the filed rate, until Rider TRG has been in effect for a longer period of time in order to gain additional experience with its implementation. (Final Order, December 8, 2021). *See also below,* Case No. PUR-2022-00101, DEV's 2022 Rider TRG update filing. § 56-577 A 5 of the Code.

- DEV 2021 RPS Filing (PUR-2021-00146). The Commission reviewed DEV's 2021 RPS Filing which included (i) DEV's RPS Development Plan (encompassing proposed development of new solar, onshore wind, and energy storage resources); (ii) requests for approval to construct 13 new utility-scale projects and to enter into 24 new PPAs; and (iii) DEV's request for approval of revised Rider CE. The Commission (i) found that, for the limited purpose of filing its second annual RPS plan under Code § 56-585.5 D 4, DEV's plan was reasonable and prudent; (ii) approved the utility-scale projects and PPAs proposed by the Company; and (iii) approved revised Rider CE. In total, the Commission approved 857 MW of new solar generation capacity and 103 MW of energy storage capacity. The Commission directed DEV to continue filing a consolidated bill analysis in its RPS Filings. The Commission also established additional directives regarding DEV's modeling in its subsequent RPS Plans (Final Order, March 15, 2022). §§ 56-580 D, 56-46.1, 56-585.1 A 6, and 56-585.1:4 of the Code.

- APCO 2021 RPS Filing (PUR-2021-00206). The Commission reviewed APCo's 2021 RPS Filing where APCo estimates that by 2040, it may have 2,736 MW (nameplate) of solar, 750 MW (nameplate) of onshore wind, and 2,937 MW (nameplate) of energy storage, through a mix of company-owned resources and

PPAs, to meet the requirements of the VCEA. The Commission found that: (i) APCo's RPS Development Plan is reasonable and prudent for the limited purpose of its second annual plan; (ii) approved APCo's requests for approval of cost recovery for 313.9 MW of solar and onshore wind capacity, including both company-owned resources and PPAs; (iii) granted APCo's request for a prudency determination for 238.9 MW of solar capacity, including company-owned resources and PPAs; (iv) approved the recovery of projected costs of RECs purchased in the PJM REC market; and (v) approved RACs for cost recovery. The Commission directed APCo to continue filing a consolidated bill analysis in its RPS Filings. The Commission also established additional directives regarding APCo's modeling in its subsequent RPS Plans. (Final Order, July 15, 2022) § 56-585.5 of the Code.

- DEV Rider PPA (PUR-2021-00248). The Commission approved DEV's application for approval of a rate adjustment clause, designated Rider PPA, to recover projected and actual costs associated with certain PPAs for the energy, capacity, ancillary services, and RECs owned by third parties. (Final Order, August 3, 2022). § 56-585.1 A 5 d of the Code.

- DEV Rider RPS (PUR-2021-00282). The Commission approved revisions to DEV's Rider RPS. Rider RPS recovers the Company's projected and actual costs related to compliance with the mandatory RPS program established in the VCEA. (Final Order, June 30, 2022). § 56-585.1 A 5 d of the Code.

- DEV - GATS Business Rules; calculating RECs for a hybrid facility (PUR-2022-00075). DEV sought an exception to the GATS Business Rules for a combination solar generator/energy storage facility (Scott Solar/BESS-3). DEV requested that the Commission direct GATS to calculate the RECs for this hybrid facility based on the amount of energy that enters the BESS-3 system as charging energy, rather than the amount of energy discharged by BESS-3 to the grid. The Commission granted DEV's petition for exception in this matter, noting that (i) no comments or requests for hearing concerning it had been filed by interested parties or the Staff, and (ii) the exception granted may be subject to modification in the future as experience is gained with these types of facilities. (Order Granting Exception to GATS Business Rules, August 12, 2022). § 56-585.5 C of the Code, and the Commission's GATS Business Rules.

Pending Cases

- Regulations for a multi-family shared solar program (PUR-2020-00124) (DEV): DEV requests approval of an administrative charge associated with the Company's participation in a program affording eligible multi-family customers of investor-owned utilities the opportunity to participate in shared solar projects.[92] (Case filed September 1, 2021). § 56-585.1:12 of the Code.

[92] KU/ODP also has a multi-family shared solar program but did not request an administrative charge be set for its program.

- Regulations for a shared solar program (PUR-2020-00125) (DEV): The Commission issued a Final Order establishing the minimum bill, which may be modified over time, and set the bill credit rate for participants in DEV's shared solar program under Code § 56-594.3. The Commission is currently considering a petition for reconsideration filed by two respondents. (Order Granting Reconsideration, July 27, 2022) § 56-594.3 of the Code.

- Axton Solar Project (PUR-2021-00085). Axton seeks Commission approval to construct a 201.1 MW solar generating facility to be constructed in Henry and Pittsylvania Counties. The Application was initially filed on April 28, 2021. Axton subsequently filed with the Commission an amended application and supporting documents. (Amended application filed March 31, 2022). §§ 56-46.1 and 56-580 D of the Code.

- DEV offshore wind generation facilities (PUR-2021-00142). The Commission issued a Final Order approving requested cost recovery associated with DEV's proposed 2,587 MW CVOW Project to be located in a federal lease area off the coast of Virginia Beach, Virginia. The project consists of 176 wind turbines, each designed to generate 14.7 MW. The project is expected to have a capital cost of $9.8 billion and will likely be the largest capital investment, and single largest project, in the history of Dominion Energy Virginia. The Commission also approved the electric interconnection and transmission facilities to connect the CVOW Project reliably with the existing transmission system. The Commission issued an Order Granting Reconsideration for purposes of retaining jurisction over the case in response to a Petition for Limited Reconsideration filed by DEV. (Final Order, August 5, 2022; Order Granting Reconsideration, August 24, 2022). §§ 56-585.1, 56-585.1:11, 56-46.1, 56-265.1 of the Code.

- DEV allocation of RPS-related costs (PUR-2021-00156). This Commission docket was established to consider issues related to DEV's recovery of its RPS related costs, and the jurisdictional and class allocation of those costs among its customers. (Case filed December 22, 2021). § 56-585.5 of the Code.

- GATS business rules (PUR-2022-00045). This Commission proceeding will consider potential revisions to the Commission's GATS business rules ("GATS Business Rules"). In particular, the Commission will consider (i) incorporating language to establish a self-certification process for resources seeking to qualify as low-income projects pursuant to Code § 56-585.5 C; and (ii) additional issues related to the GATS Business Rules. (Case docketed April 14, 2022). § 56-585.5 C of the Code.

- DEV Rider TRG (PUR-2022-00101). DEV seeks approval of an annual update of its 100 percent renewable energy tariff, designated Rider TRG whereby participating customers can voluntarily elect to purchase 100 percent of their

energy grid capacity needs sourced from renewable energy resources. (Case filed July 1, 2022). §§ 56-577 A 5 and 56-234 of the Code.

Environmental Cases

Below is a table summarizing the environmental cases decided by or pending before the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Rider E (Update)	Resolved	§ 56-585.1 A 5	PUR-2021-00013
DEV	Rider CCR	Resolved	§ 10.1-1402.03	PUR-2021-00045
DEV	Rider RGGI Update	Resolved	§ 56-585.1 A 5	PUR-2021-00281
APCo	Environmental RAC	Pending	§ 56-585.1 A 5	PUR-2022-00001
DEV	Rider E (Update)	Pending	§ 56-585.1 A 5	PUR-2022-00006
DEV	Rider CCR	Pending	§ 10.1-1402.03	PUR-2022-00033
DEV	Rider RGGI (Suspension)	Resolved	§ 56-585.1 A 5	PUR-2022-00070

Decisions

- DEV Rider E (PUR-2021-00013). The Commission approved DEV's annual update to its Rider E to recover costs incurred to comply with state and federal environmental regulations at the Company's Chesterfield, Bremo, Clover, and Mt. Storm Power Station. (Final Order September 23, 2021). § 56-585.1 A 5 e of the Code.

- DEV Rider CCR (PUR-2021-00045). The Commission approved DEV's application seeking approval of Rider CCR to recover costs related to the removal of coal combustion residual from DEV's Bremo, Chesterfield, and Possum Point Power Stations and Chesapeake Energy Center. Such approval was made subject to certain cost allocations, reporting, and filing requirements applicable to future Rider CCR updates. (Final Order, October 6, 2021). §§ 56-585.1 A 5 e and 10.1-1402.03 of the Code.

- DEV Rider RGGI Update (PUR-2021-00281). On December 26, 2021, DEV filed an annual update of the Company's rate adjustment clause, Rider RGGI. This

Rider recovers projected and actual costs related to the purchase of allowances through the RGGI market-based trading program for carbon dioxide emissions. DEV subsequently sought, and the Commission granted, the Company's motion to withdraw the update filing, subject to future update and filing requirements. (Order Granting Motion, April 1, 2022). See, also, related docket, Case No. PUR-2022-00070. § 56-585.1 A 5 e of the Code.

- DEV Rider RGGI Suspension (PUR-2022-00070). The Commission approved DEV's May 5, 2022, petition to suspend Rider RGGI and to reset the Rider RGGI Projected Cost Recovery Factor to $0.00/kWh, effective July 1, 2022. The Commission further authorized DEV to recover RGGI compliance costs that are incurred up through July 31, 2022 (and ultimately approved by the Commission), and which have not been recovered prior to the suspension of the Rider through DEV's base rates for generation services in effect during the period incurred. This docket will remain open for future proceedings, including but not limited to an actual cost true-up proceeding to review incurred allowance costs that have been recovered through Rider RGGI. (Order Granting Petition, June 15, 2022). § 56-585.1 A 5 e of the Code.

Pending Cases

- APCo Environmental RAC (PUR-2022-00001). APCo seeks Commission approval to recover costs through its existing rate adjustment clause, the E-RAC, related to capital investments and operations and maintenance compliance expenses that are necessary to comply with state and federal environmental regulations. (Case filed March 18, 2022). § 56-585.1 A 5 e of the Code.

- DEV Rider E Update (PUR-2022-00006). DEV seeks an update to its Rider E to recover costs incurred to comply with state and federal environmental regulations at the Company's Chesterfield, Bremo, Clover, and Mt. Storm Power Stations. (Case filed January 25, 2022). § 56-585.1 A 5 e of the Code.

- DEV Rider CCR (PUR-2022-00033). DEV seeks to update its Rider CCR RAC. (Case filed February 28, 2022) §§ 56-585.1 A 5 e and 10.1-1402.03 of the Code.

Retail Access Cases

Below is a table summarizing the retail access cases decided by or pending before the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Aggregation Pilot	Continued	Chapter 796 of the 2020 Virginia Acts of Assembly	PUR-2020-00114
DEV	RPS Cost Allocation Proceeding	Resolved	§ 56-585.5 F	PUR-2020-00164

Decisions

- DEV RPS Cost Allocation to shopping customers (PUR-2020-00164). In this proceeding, DEV sought approval of its proposal to recover the non-bypassable RPS costs associated with Code § 56-585.5 F, net of benefits, from customers electing to take electric supply service from a competitive service provider. However, as part of the Commission's 2020 RPS Final Order, the Commission adopted the general RAC framework for the recovery of RPS-related costs as proposed by Staff, and as refined by Dominion, under which the Company will recover costs of resources approved under the VCEA, including the non-bypassable charge, in a single rate mechanism. As such, the Commission determined in this proceeding that Rider NBC (proposed by DEV) is no longer needed. Issues related to distinguishing between RPS Program compliance costs and other costs, as well as class cost allocation methodology and ARBs, will be addressed in appropriate subsequent proceedings, including Case No. PUR-2021-000156, discussed *supra*. (Final Order, September 23, 2021). §§ 56-585.5 and 56-585.1:11 of the Code.

Continued Cases

- DEV Aggregation Pilot (PUR-2020-00114). Pursuant to legislation passed by the 2020 General Assembly, the Commission established a pilot program through which non-residential customers that had previously sought to aggregate their load pursuant to Code § 56-577 A 4 in DEV's service territory would be permitted to purchase electric energy from a competitive service provider, subject to an overall cap of 200 MW of load participating in the Pilot. On June 17, 2022, the Commission issued an Order (i) finding that the Pilot should continue and remain open to any non-residential customer who is eligible for, and wishes to participate in, the Pilot; and (ii) continuing the case. Chapter 796 of the 2020 Virginia Acts of Assembly**.**

Energy Efficiency Cases

Below is a table summarizing the energy efficiency cases decided by or pending before the Commission at the time of this report. A description of the proceedings

follows the table. Both APCo (a Phase I Utility) and DEV (a Phase II Utility) estimate that they are on target to implement energy efficiency programs and measures to achieve the total annual energy savings targets for 2023 as specified by Code § 56-596.2.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Evaluation, Measurement and Verification (EM&V) Methodologies	Resolved	§ 56-585.1 A 5	PUR-2020-00156
DEV	DSM RAC and Phase IX Programs	Resolved	§ 56-585.1 A 5	PUR-2020-00274
APCo	Energy Efficiency RAC and New Program	Resolved	§ 56-585.1 A 5	PUR-2021-00236
DEV	DSM RAC and Phase X Programs	Resolved	§ 56-585.1 A 5	PUR-2021-00247

Decisions

- DEV EM&V "Dashboard" proceeding (PUR-2020-00156). This Commission proceeding established guidelines for DEV's evaluation, measurement, and verification ("EM&V") reports related to the Company's DSM programs. DSM programs include energy efficiency and peak-shaving programs. EM&V reports address energy savings produced by such programs. (Final Order, October 27, 2021). § 56-585.1 A 5 of the Code.

- APCo Energy Efficiency RAC and New Program (PUR-2021-00236). The Commission approved APCo's application for approval of the continued implementation of its rate adjustment clause, the EE-RAC, to recover the costs of its existing portfolio of DSM programs, as well as for approval of one new pilot program, the Commercial and Industrial Custom Pilot Program. (Final Order, July 15, 2022). §§ 56-585.1 A 5 and 56-596.2 of the Code.

- DEV DSM RAC and Phase IX Programs (PUR-2020-00274). The Commission approved DEV's application seeking approval of its Phase IX DSM programs, including 11 new energy efficiency and demand response programs, the expansion and modification of certain existing programs, and approval of cost recovery through associated RACs. The Commission's approval was made subject to certain cost caps together with requirements for future DSM filings. (Final Order, September 7, 2021). § 56-585.1 A 5 of the Code.

- DEV DSM RAC and Phase X Programs (PUR-2021-00247). The Commission approved, among other things, (i) DEV's proposed Phase X DSM Programs including proposed enhancement and expansion of certain previously approved programs; (ii) reorganization and consolidation of the DEV's DSM Portfolio; and (iii) cost recovery through associated RACs. § 56-585.1 A 5 of the Code. (Final Order, August 10, 2022). § 56-585.1 A 5 of the Code.

Distribution Cases

Below is a table summarizing the distribution cases decided by or pending before the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
APCo	Broadband Project	Resolved	§ 56-585.1:9	PUR-2020-00259
DEV	Rider GT	Resolved	§ 56-585.1 A 6	PUR-2021-00083
DEV	Rider U (Update)	Resolved	§ 56-585.1 A 6	PUR-2021-00110
DEV	Grid Transformation Plan	Resolved	§ 56-585.1 A 6	PUR-2021-00127
APCo	Broadband Project	Pending	§ 56-585.1:9	PUR-2022-00020
DEV	Broadband Project	Pending	§§ 56-585.1 A 6 and 56-585.1:9	PUR-2022-00062
SCC	Interconnection of Distributed Energy Resources	Pending	Pursuant to Final Order in Case No. PUR-2021-00127	PUR-2022-00073
DEV	Rider U (Update)	Pending	§ 56-585.1 A 6	PUR-2022-00089

Decisions

- APCo Broadband Project (PUR-2020-00259). The Commission approved APCo's petition seeking approval of a rate adjustment clause, the BC-RAC, for cost recovery of providing broadband capacity through its previously

approved Grayson County broadband pilot. (Final Order, October 1, 2021). §§ 56-585.1 A 6 and 56-585.1:9 of the Code.

- DEV Rider GT (PUR-2021-00083). The Commission approved DEV's application for a new rate adjustment clause, designated Rider GT, to recover certain costs of the Company's grid modernization plan that the Commission previously approved in Case Nos. PUR-2018-00100 and PUR-2019-00154. (Final Order, May 13, 2022). § 56-585.1 A 6 of the Code.

- DEV Rider U Strategic Undergrounding Program (PUR-2021-00110). The Commission approved DEV's annual update to Rider U. (Final Order, March 9, 2022). § 56-585.1 A 6 of the Code.

- DEV Grid Transformation Plan (PUR-2021-00127). The Commission approved DEV's third grid modernization proposal, which included requested approval of $669.4 million of capital investments and $109.5 million of operations and maintenance expense. The Commission's approval of these projects was made subject to certain contingencies, cost caps, and reporting requirements. (Final Order, January 7, 2022). § 56-585.1 A 6 of the Code.

Pending Cases

- APCo Broadband Project (PUR-2022-00020). APCo seeks approval of a new project to make available broadband capacity to an Internet Service Provider in parts of Bland County and Montgomery County and to revise its BC-RAC to reflect actual costs of providing broadband capacity under the Company's existing broadband project as well as the new project. (Case filed June 8, 2022) §§ 56-585.1 A 6 and 56-585.1:9 of the Code.

- DEV Broadband Project (PUR-2022-00062). DEV seeks approval to install middle-mile broadband capacity in certain unserved areas of Virginia, including the Northern Neck region and the Thomas Jefferson Planning District. The Company also seeks approval to revise rate adjustment clause Rider RBB, for the rate year commencing December 1, 2022, through November 20, 2023. (Case filed May 5, 2022). §§ 56-585.1 A 6 and 56-585.1:9 of the Code.

- Interconnection of Distributed Energy Resources (PUR-2022-00073). This Commission docket was established (pursuant to the Commission's Final Order in Case No. PUR-2021-00127) to address obstacles to the interconnection of distributed energy resources on electric utilities' distribution systems. (Docket established May 24, 2022).

- DEV Rider U Strategic Undergrounding Program (PUR-2022-00089). DEV seeks an annual update to Rider U. (Case filed June 13, 2022). § 56-585.1 A 6.

Integrated Resource Plan Cases

Below is a table summarizing the IRP cases decided by or pending before the Commission at the time of this report. A description of each proceeding follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Integrated Resource Plan Update	Resolved	§ 56-597 *et seq.*	PUR-2021-00201
APCo	Integrated Resource Plan	Pending	§ 56-597 *et seq.*	PUR-2022-00051

Decisions

- DEV IRP Update (PUR-2021-00201). On September 1, 2021, DEV filed with the Commission the Company's 2021 update to its 2020 Integrated Resource Plan. The Commission found this update legally sufficient and accepted it for filing. The Commission stated, however, that such acceptance does not express approval of the magnitude or specifics of Dominion's future spending plans. (Final Order, October 28, 2021). § 56-599 of the Code.

Pending Cases

- APCo IRP (PUR-2022-00051). APCo has filed its 2022 IRP. Per the filing, the IRP, among other things, incorporates requirements of the VCEA related to resource acquisition, includes the most recent load forecast consistent with the VCEA, and incorporates updated renewable costs. The Commission will hear this case starting October 24, 2022. (Case filed April 29, 2022). § 56-599 of the Code.

Financial Review Cases

Below is a table summarizing the financial review cases decided by or pending before the Commission at the time of this report.

Company	Topic	Pending or Resolved?	Code Section	Case No.
APCo	Triennial Review	Pending	§ 56-585.1 A	PUR-2020-00015

DEV	Triennial Review	Resolved	§ 56-585.1 A	PUR-2021-00058

Decisions

- DEV Triennial Review (PUR-2021-00058). On March 31, 2021, DEV filed its application for the Commission's triennial review of the Company's rates, terms, and conditions for the provision of generation, distribution, and transmission services. The Commission Order in this case approved a stipulation that principally provided (i) customer refunds totaling $330 million; and (ii) the statutory maximum annual rate reduction of $50 million. (Final Order, November 18, 2021). § 56-585.1 A 3 of the Code.

Pending

- APCo Triennial Review (PUR-2020-00015). The Commission, among other things, determined that in the 2017-2019 triennial period under review, Appalachian earned 6 basis points above the fair ROE, which equates to approximately $1,992,987 in excess earnings for such period. Upon appeal to the Supreme Court of Virginia, on August 18, 2022, the Court affirmed in part, reversed in part, and remanded the case to the Commission for further proceedings consistent with the Court's opinion. (Final Order, November 24, 2020; Order on Reconsideration, March 26, 2021; Notice of Appeal, April 5, 2021; Petition of Appeal, July 6, 2021; Opinion of the Supreme Court of Virginia, Aug. 18, 2022; Order Initiating Remand Proceedings, August 22, 2022). § 56-585.1 A 3 of the Code.

See also, Section III, Base Rate Financial Results, of this report for details on these cases.

Miscellaneous Cases

Below is a table summarizing miscellaneous cases decided by or pending before the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Universal Service Fee/Rider PIPP	Pending	§ 56-585.6	PUR-2020-00109
APCo	Universal Service Fee/Rider PIPP	Pending	§ 56-585.6	PUR-2020-00117
DEV	Rider SNA	Resolved	§ 56-585.1 A 6	PUR-2021-00229

Decisions

- DEV Rider SNA (PUR-2021-00229). The Commission approved DEV's application for a RAC, Rider SNA, to recover the Company's costs associated with (i) preparing petitions to the Nuclear Regulatory Commission to extend the operating licenses of Dominion's Surry Units 1 and 2 and North Anna Units 1 and 2; and (ii) the projects reasonably appropriate to upgrade or replace systems and equipment deemed to be necessary to operate these units safely and reliably. (Final Order, July 1, 2022). § 56-585.1 A 6 of the Code.

Pending

- Percentage of Income Payment Program (DEV: PUR-2020-00109; APCo: PUR-2020-00117). The VCEA requires the Commission to determine the universal service fees to be collected from customers of APCo and DEV to fund the Percentage of Income Payment Program ("PIPP") established by statute. PIPP eligible utility customers are persons or households whose income does not exceed 150 percent of the federal poverty level.[93] § 56-585.6 of the Code.

  The Commission authorized DEV and APCo to begin collecting a universal service fee from the statutorily designated customers as soon as practicable, effective for service rendered on and after September 1, 2021, at a level designed to fund the estimated start-up costs of Department of Social Services ("DSS") needed to establish the PIPP. The Commission also continued the proceedings to determine the rates, terms, and conditions of a "non-bypassable universal service fee" to be charged to DEV and APCo's customers to fund the PIPP, instructing both utilities to file within 60 days after DSS rules or guidelines are published. (Orders, July 29, 2021). To date, DSS has not published these rules or guidelines. Consequently, neither APCO nor DEV has been required to make additional filings of their respective PIPP dockets, as otherwise required by the Commission's July 20, 2021 Orders.

V.
STAKEHOLDER MEETINGS

The Staff has been involved in multiple stakeholder meetings over the last year as required by recent legislation. Staff has attended these meetings as a resource to provide technical information or background on Commission procedures and proceedings. The following is a list of meetings the Staff has attended:

[93] Code § 56-576.

- Energy Efficiency Meetings: (required by SB 966,[94] SB 1605,[95] and HB 2293[96]) held on November 8, 2021, and April 25, 2022, for APCo; and, August 31, 2021, November 17, 2021, February 22, 2022, and, June 21, 2022, for DEV.

- Transportation Electrification Stakeholder Group Meetings: (required by HB 2282[97]) held on October 21, 2021, November 4, 2021, November 18, 2021, December 2, 2021, and December 16, 2021.

- Program to Encourage and Expedite Electric Utility Infrastructure Investments Stakeholder Meetings: (required by HB 894[98]) held on June 23, 2022, July 5, 2022, July 13, 2022, and July 25, 2022.

- Renewable Energy Facilities Lifecycle Task Force Meeting: (required by SB 499 and HB 774[99]) The Commission is in the process of selecting a third-party facilitator for this task force. Task force meetings are expected to occur in the fall of 2022.

- Shared Solar Stakeholder Workgroup for APCo and Kentucky Utilities: (required by SB 660[100]) The Commission is in the process of selecting a third-party facilitator for this work group. Stakeholder workgroup meetings are expected to occur in the fall of 2022.

VI.
PJM / FERC STATUS

DEV and APCo are members of PJM, a regional transmission organization that coordinates the movement of wholesale electricity across all or parts of the District of

[94] 2018 Va. Acts ch. 296.

[95] 2019 Va. Acts ch. 398.

[96] 2019 Va. Acts ch. 397.

[97] 2021 Va. Acts, Special Session I, ch. 268.

[98] 2022 Va. Acts ch. 488.

[99] 2022 Va. Acts chs. 69 and 70.

[100] 2022 Va. Acts ch. 591.

Columbia and 13 states.[101] Below is a list of recent matters involving PJM and FERC that may impact Virginia:

- In June 2018, FERC invalidated PJM's capacity market design. FERC ruled that state-subsidized resources were artificially and improperly suppressing market prices.[102] Following a FERC technical conference on wholesale market reform in March 2021, during which the FERC Chairman indicated FERC would take action to address deficiencies in the Minimum Offer Price Rule ("MOPR") (including concerns that the MOPR could cause undue burden to resources supported by state policies) by year-end if PJM did not do so, PJM initiated an accelerated stakeholder process, or Critical Issue Fast Path. On July 30, 2021, PJM filed its replacement MOPR proposal in Docket No. ER21-2582. On September 29, 2021, FERC allowed PJM's proposal to become effective by operation of law, stating that "[t]he Commission did not act on PJM's filing because the Commissioners are divided two against two as to the lawfulness of the change."[103] Several parties, including other state commissions, have appealed FERC's order.

- In April 2021, DEV announced that it would elect to procure its capacity through the Fixed Resource Requirement alternative to the PJM capacity market auction.[104] A competitive power supplier challenged PJM's approval of this election. FERC rejected this challenge on July 15, 2021.

- In September 2020, FERC issued Order 2222, which adopted reforms to allow distributed energy resource aggregations to participate in the regional transmission organization markets.[105] PJM made its compliance filing on February 1, 2022, outlining how it will comply with Order 2222.[106]

- On June 30, 2021, the transmission owners ("Transmission Owners") in the PJM region submitted a consolidated filing at FERC that proposed revisions to the PJM Tariff to provide Transmission Owners with the option to elect to fund the capital

[101] Specifically, the 13 states consist of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

[102] *Calpine Corp. v. PJM Interconnection, LLC*, 163 FERC ¶ 61,236 (2018).

[103] *PJM Interconnection L.L.C.*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (Sep. 29, 2021).

[104] APCo has always chosen the PJM Fixed Resource Requirement alternative since joining PJM in 2004.

[105] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (September 19, 2020).

[106] *PJM Interconnection, L.L.C.*, Docket No. ER22-962.

cost of network upgrades necessary to accommodate generator interconnections.[107] The proposed revisions would allow the PJM Transmission Owners the opportunity to earn a return of and on the costs of network upgrades that are necessary to interconnect generation resources to the PJM transmission system. Under the current tariff, those costs must be paid by the interconnecting generator. FERC set this matter for paper hearing on November 19, 2021, and parties filed briefs in January 2022.

- On July 19, 2021, PJM filed a brief in a Pennsylvania federal court case challenging the Pennsylvania Public Utility Commission's ("PAPUC") rejection of a transmission line. Following the PAPUC's order, the developer (TransSource) sued the PAPUC in federal court, alleging that the PAPUC's decision violated the dormant Commerce Clause and was preempted by PJM's earlier determination of need. PJM claims that the PAPUC does not have authority to reject a line on the grounds that the line is not needed where PJM has concluded the line is necessary under mechanisms approved by FERC. On August 26, 2021, the District Court denied in part PAPUC's motion to dismiss, finding that TransSource had standing to file the action. The court abstained on the remainder of the motion, electing to wait until an appeal in state court was completed. On May 6, 2022, the Pennsylvania Commonwealth Court upheld the PAPUC's order rejecting the line. The District Court lifted its stay of the proceedings on May 17, 2022, and discovery in the case is ongoing. The current schedule calls for discovery to continue until January 2023, with dispositive motions and supporting briefs due on or before February 15, 2023.

- On April 21, 2022, FERC issued a Notice of Proposed Rulemaking ("NOPR") seeking comment on the potential need for change to existing regulations on electric regional transmission planning, cost allocation, and generator interconnection processes.[108] Comments were due by August 17, 2022.

- On June 14, 2022, PJM proposed changes to its generator interconnection process, seeking to change from a first-come, first-served process to a first-ready, first-served process, to give priority to projects that are more likely to be completed.[109] PJM claims this will help alleviate significant queue backlogs.

- On June 16, 2022, FERC issued a NOPR, proposing changes to its interconnection procedures to address interconnection queue backlogs, improve

[107] *PJM Tariff Revisions to Implement Transmission Owners' Funding of Network Upgrades*, Docket No. ER21-2282 (June 30, 2021).

[108] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (Apr. 21, 2022).

[109] *PJM Interconnection, L.L.C.*, Docket No. ER22-2110.

certainty, and prevent undue discrimination for new technologies.[110] Comments on the NOPR are due October 13, 2022.

VII.
CONSUMER EDUCATION

The Regulation Act, specifically § 56-592 of the Code, directs the Commission to establish, implement, and maintain a consumer education program to provide retail customers with information regarding energy conservation and efficiency, DSM, demand response, and renewable energy. The Virginia Energy Sense ("VES") consumer education program is in its twelfth year of building awareness of the value of energy efficiency.

Highlighted VES accomplishments from the last year (July 1, 2021 – June 30, 2022) are as follows:

- VES' new contract team comprehensively analyzed communications about consumer energy in Virginia and developed a messaging framework to guide the program's strategies and activities.
- To measure public attitudes on energy conservation, VES conducted an online quantitative survey, which garnered responses from 1,208 Virginia residents. Survey results suggested that awareness of the VES program remains high; approximately 1 in 4 respondents recalled recently seeing or hearing messages from or about VES.
- VES secured 10 news stories about the program and its energy saving tips in 10 media outlets, including TV stations in Richmond, Charlottesville, and Norfolk.
- Following a pandemic-driven pause in community outreach events, VES exhibited at three in-person events in spring 2022. The events' total attendance was approximately 75,400.
- VES ran two statewide radio advertising campaigns that collectively generated over 9.7 million impressions. The campaigns ran in October 2021 and April –

[110] *Improvements to Generator Interconnection Procedures and Agreements*, Docket No. RM22-14, 179 FERC ¶ 61,194 (June 16, 2022).

May 2022 and drove a 31.5% and a 16.3% increase in web visits, respectively. VES also created 36 public service announcements for radio, tailored to the six regions of Virginia, that collectively garnered around 120,000 impressions as of May 31, 2022.

- A VES advertising campaign on Facebook and Instagram that ran from May 4 to June 1, 2022, garnered over 2.8 million impressions and drove 12,627 visits to VES' new "10 ways to save" landing page, shown below:

- The VES website garnered 19,891 site visits and 22,833 page views.

- VES published 218 posts on its Facebook and Twitter accounts, reaching 31,625 users and generating 722 engagements. VES also relaunched its Instagram account in March 2022.

VIII.
CLOSING

Code § 56-596 directs the Commission to provide "recommendations for any actions by the General Assembly, the Commission, electric utilities, or any other entity that the Commission considers to be in the public interest."[111] While the Commission has no statutory recommendations at this time, we bring to the General Assembly's attention a matter for its consideration, specifically the Commission's lack of proactive authority, under current law, to protect reliability and security of electric service resulting from VCEA-directed retirements unless there is a request by the utility. Code § 56-585.5 B prescribes certain retirements of fossil fuel generation owned by Phase I (APCo) and Phase II (DEV) utilities.

Code § 56-585.5 B 4 further states:

> A Phase I or Phase II Utility [APCo or DEV] *may* petition the Commission for relief from the requirements of this subsection on the basis that the requirement would threaten the reliability or security of electric service to customers. The Commission shall consider in-state and regional transmission entity resources and shall evaluate the reliability of each proposed retirement on a case-by-case basis in ruling upon any such petition.[112]

The Commission appreciates the General Assembly's awareness of the importance of reliability and security of electric service to end-use customers. That said, the above

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[111] Specifically, Code § 56-596 B.

[112] Emphasis added. Similarly, Enactment Clause 9 of the VCEA reads:

> That nothing in this act shall require the utilities or the State Corporation Commission to take any action that, in the State Corporation Commission's discretion and after consideration of all in-state and regional transmission entity resources, threatens the reliability or security of electric service to the utility's customers.

While this Enactment Clause appears to protect the Commission *from having to* act, it does not appear to give the Commission authority *to* act.

provisions leave it to *the utility's* discretion whether to seek relief from VCEA requirements. The utility still has the ability to decide to retire and/or impair generating units even though customers may still be required to pay for such units. An after-the-fact review or finding of harm to reliability and/or security of electric service would leave the Commission with few options to protect customers.

If the General Assembly intends to leave this discretion solely in the hands of utilities, that is what the current law accomplishes. The General Assembly may wish to consider a required update or analysis from the Commission in close proximity and prior to unit closure.

The Commission continues to execute its responsibilities under the Regulation Act and stands ready to implement the laws passed by the General Assembly.

APPENDIX 1

GLOSSARY OF TERMS

ARPA	American Rescue Plan Act of 2021
APCo	Appalachian Power Company
Code	Code of Virginia
CTs	Combustion Turbines
Commission	Virginia State Corporation Commission
CRF	Coronavirus Relief Funds
Consumer Counsel	Office of the Attorney General, Division of Consumer Counsel
CVOW Project	Coastal Virginia Offshore Wind Commercial Project
DEI	Dominion Energy, Inc.
DEV	Virginia Electric and Power Company d/b/a Dominion Energy Virginia
Dominion	Virginia Electric and Power Company d/b/a Dominion Energy Virginia
DSM	Demand-side Management
DSS	Department of Social Services
EE	Energy Efficiency
EM&V	Evaluation, Measurement, and Verification
FERC	Federal Energy Regulatory Commission
GATS	PJM-EIS Generation Attribute Tracking System
GTSA	Grid Transformation and Security Act, Chapter 296 of the 2018 Acts of Assembly
IRP	Integrated Resource Plan
KU/ODP	Kentucky Utilities Company d/b/a Old Dominion Power Company
kWh	Kilowatt-hour
MOPR	Minimum Offer Price Rule
MW	Megawatt
NOPR	Notice of Proposed Rulemaking
PAPUC	Pennsylvania Public Utility Commission
PIPP	Percentage of Income Payment Program
PJM	PJM Interconnection, L.L.C.
PPA	Power Purchase Agreement
RAC	Rate Adjustment Clause
RGGI	Regional Greenhouse Gas Initiative
REC	Renewable Energy Certificate
Regulation Act	Virginia Electric Utility Regulation Act, codified at Code §§ 56-576 through 56-596.3
ROE	Return on Equity
RPS	Renewable Energy Portfolio Standard
Staff	State Corporation Commission Staff
VCEA	Virginia Clean Economy Act, Chapters 1193 and 1194 of the 2020 Acts of Assembly
VES	Virginia Energy Sense, a State Corporation Commission consumer education program

Attachment 68

ENERGY + ENVIRONMENT

Virginians feeling the heat of high utility bills this winter

Global pressures, higher natural gas prices leading utilities to seek higher rates

BY: **CHARLIE PAULLIN** - FEBRUARY 20, 2023 12:04 AM

Natural gas meter with pipe on wall. (Getty Images)

On Christmas Eve 2022, temperatures in central Virginia hit a low of 8 degrees, 17 degrees below the record in 2021, according to the National Weather Service.

That and several other arctic blasts this winter came amid global conflicts like war in Ukraine that have strained natural gas supply in the U.S. At the same time, there has been an increase

in the use of natural gas to generate energy for the electric grid as more and more coal-fired plants come offline.

As a result, the U.S. Energy Information Administration predicted in October that natural gas bills in the South could increase during the October to March winter season by $761, or 24%, compared to the year before. Some 28% of homes in the South rely on natural gas for heat.

For homes relying on electricity for heat, bills could increase by $1,249, or 12%. About 65% of homes in the South rely on electricity for heat.

Virginia has eight investor-owned natural gas providers, two large electric utilities and 13 electric cooperatives that are regulated by the State Corporation Commission. There are also three municipal governments – Richmond, Danville and Charlottesville – that provide natural gas and are regulated by their city councils.

In filings with the State Corporation Commission and interviews with the Mercury, all gas and electric providers have acknowledged that global price pressures on natural gas are affecting customers' bills.

Southwest Virginia Gas Company, "like any other entity that purchases natural gas, has seen increases to the costs it pays for natural gas," wrote president and CEO James McClain II in one representative request to the SCC for a rate increase.

All of Virginia's electric and gas providers have assistance programs for customers to help alleviate the burden of rising bills. Millions of dollars are also available through state assistance and energy efficiency programs.

But customer advocates say all those programs can be improved.

"I don't think there's anybody out there that doesn't really want to make efforts to help utility customers," said Dana Wiggins, director of the Center for Economic Justice at the Virginia Poverty Law Center.

Investor-owned utilities

State law allows investor-owned natural gas and electricity companies like Dominion Energy, Appalachian Power Company and Virginia Natural Gas to recover their operating costs and earn a reasonable profit from customers.

Fuel costs are recouped from customers without any extra profit for the companies.

In filings with the SCC over the past few months, numerous gas and electric utilities have asked to raise rates to make up for rising fuel costs, as well as others like lost COVID-19 revenues from forgone late fees and inflationary pressures.

Roanoke Gas Company "is experiencing significant inflationary pressure on costs and prices for labor and benefits, insurance, pension, and bad debt, among other operating and

maintenance expenses," attorney Timothy E. Biller wrote in one filing.

Columbia Gas of Virginia, which serves about 285,000 customers in the eastern and central regions of Virginia, is asking for an average monthly residential bill increase of 12.37%. Roanoke Gas, which serves about 63,500 customers around Roanoke, is seeking a $2 residential customer charge increase. Southwest Virginia Gas Company, which serves about 4,300 customers around Martinsville, is seeking a rate increase that would add roughly $7.88 to the average residential customer's monthly bill. Virginia Natural Gas, which serves 312,000 customers in Tidewater Virginia, received an increase that would affect average monthly customer bills by $12.88.

"Despite our best efforts to keep costs down, the Company has experienced substantial increases in costs along our entire supply chain for capital, goods, services and personnel which has resulted in the need to seek a base rate increase," testified Paul Nestor, president and CEO of Roanoke Gas Company.

Dominion and Appalachian Power have also sought rate increases to cover spiking fuel costs. In September, the State Corporation Commission approved an increase for Dominion that added roughly $14.93 to the average residential customer's monthly bill. Appalachian Power is seeking about a $20 monthly bill increase.

The Dominion request sought to cover a $1 billion gap between expected and actual fuel costs for 2022 and almost $2.3 billion in projected costs for the year between July 2022 and June 2023.

According to a 2021 long-range plan filed by Dominion, natural gas constituted 40% of the fuel used for electricity generation that year. Nuclear accounted for 29%, while renewable energy sources like solar accounted for 4%.

"The mix is going to noticeably change as we add more renewables," Dominion Energy spokesperson Craig Carper said.

Municipal utilities

The municipal utilities, meanwhile, have adjusted their rates more periodically to avoid cost increases and, more recently, reflect subsiding fuel costs.

In Richmond, the purchased gas cost, which is passed directly on to customers, almost doubled between January and July 2022. It has since decreased to reflect what Richmond Department of Public Utilities spokesperson Rhonda Johnson called "actual market conditions" but remained 15% higher than the prior year in January 2023.

Charlottesville, in contrast, has seen gas bills fall by about 1.2%: This January, the average customer bill was $52.63 total, compared to $53.27 in January 2022.

Comparatively, the city of Danville purchased their natural gas for this winter at more affordable times, when it was about $5.50 a unit. Over the summer, costs spiked to $8 to $9.

Costs lowered to about $7 a unit in December.

“It’s kind of like an insurance policy,” Danville Utilities Director Jason Grey said

Lending a hand

All of the utilities offer varying levels of energy assistance, from monthly bill payment plans to weatherization programs.

On a larger scale, the state offers several ways to help with utility payments.

Utility customers in crisis or emergency situations can get financial help like bill payment assistance, security deposit coverage and fuel assistance funding to help pay for heating bill costs through the Virginia Department of Social Services.

Typically, $7 million in federal funds are allocated for crisis benefits, which are available to people facing a utility cutoff or broken heating equipment, according to an email from DSS. There were almost 1,000 applications for crisis assistance between the program’s opening in November and late December.

For fuel assistance, Virginia typically gets $45 million through the federal Low Income Housing Energy Assistance Program, or LIHEAP, said the department, but this year it got $50 million. That money is funneled into a state program called Energy Assistance. There were 128,000 applications for fuel assistance this year, with over 107,000 approved by late December.

“The number of applicants for fuel assistance has increased about 5% over last year,” said the department in its email. In recent years, about 10% of Virginia households that use natural gas as a heat source have gotten fuel assistance. Overall, about 65% of funding recipients use natural gas.

On the weatherization side, the Department of Housing and Community Development oversees Virginia’s Weatherization Assistance Program, which provides financial assistance for home improvements such as heating and cooling upgrades and insulation installation or air sealing to ensure heat is generated efficiently and contained within a home.

Last year, 1,075 Virginia households received about $20 million in services through the Weatherization Assistance Program, according to department spokesperson Amanda Love.

Weatherization Assistance Program funds are also federally sourced, with $4.4 million from the U.S. Department of Energy and $14 million from the U.S. Department of Health and Human Services.

Virginia has also received over $225 million for low-income energy efficiency programs from the state’s participation in the Regional Greenhouse Gas Initiative, a multistate cap-and-invest program under which electricity producers must buy allowances for the carbon they emit. The proceeds from the purchases are then returned to the state.

From that funding, $45 million has been allocated to the Weatherization Deferral Program, which pays for repairs to homes that make them ready for weatherization efforts, and $115 million to an Affordable and Special Needs Housing program that is geared toward building homes. An additional $11.4 million has gone toward repair assistance for homes in the town of Hurley damaged in catastrophic floods in 2021.

Virginia received $272,646 for the Weatherization Readiness Fund, which also goes toward making homes ready for weatherization upgrades, as part of 2022 annual appropriations from the U.S. Department of Energy.

Program changes

Some advocates say Virginia can help shield customers from the volatility of global energy markets through utility regulation reform.

For Wiggins of the Virginia Poverty Law Center, that includes reviving the state's Commission on Energy Utility Regulation to assist with crafting policies for state oversight of publicly regulated utilities.

Instead of relying on a part-time legislature to take up reforms in the complex energy sector, Wiggins said a year-round commission could give deeper consideration to proposals such as factoring in a cost of living index to account for rents when structuring rates. Bills mandating two commission meetings per year are still alive in the final days of this session.

The state could also bulk up its utility cutoff protections, said Kidest Gebre, communications and campaigns manager for the grassroots group Interfaith Power and Light. Del. Irene Shin, D-Fairfax, filed a bill this session to prevent utilities from disconnecting services to residential customers for not paying bills during a state of emergency – a proposal she also put forward in 2022 – but it failed in committee.

"It's a long haul to change over the system," Wiggins said.

Wiggins said improvements can also be made to how bill assistance funding, particularly through LIHEAP, is doled out. Application windows are short, she said – requests for assistance during heating emergencies have to be made between the first workday in January and March 15, for example – and "funding does run out very quickly."

On the federal level, the recently passed Inflation Reduction Act offers a variety of tax credits to install new, more efficient technologies like heat pumps.

But a decision to electrify a home depends on a family's economic circumstances.

"It's something that [low-income] families can't actually afford to do," Wiggins said.

That's where funding from RGGI is a game changer, said Chelsea Harnish, executive director of the Virginia Energy Efficiency Council. While federal funding can only be used to cover a portion of each weatherization and energy efficiency project, she said, state programs funded

by RGGI dollars can be used to cover the entirety of upgrades. Projects have included repairs of 52 low-income houses in Shenandoah County and roof and new heating and cooling system installations in Crewe.

One recent report from Virginia Commonwealth University's L. Douglas Wilder School of Government and Public Affairs found that if Virginia stayed in RGGI through 2030, improvements could be made to 100,000 to 130,000 low-income homes under the state's energy efficiency programs. That could result in $68 to $82 million in customer bill savings per year, an average of $676 per year per household, researchers found.

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CHARLIE PAULLIN

Charles Paullin covers energy and environment for the Mercury. He previously worked for Northern Virginia Daily in the Northern Shenandoah Valley and for the New Britain Herald in central Connecticut. An Alexandria native, Charles graduated from the University of Hartford initially wanting to cover sports. He's received several Virginia Press Association awards for his coverage of crime, local government and state politics.

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Attachment 69

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May 5, 2022

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1300 East Main Street
Richmond, Virginia 23219

Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6
Case No. PUR-2022-00064

Dear Mr. Logan:

Please find enclosed for filing in the above-captioned proceeding an unbound original and one (1) copy of the **public version** of the *Application of Virginia Electric and Power Company to revise its fuel factor pursuant to Va. Code § 56-249.6.* A confidential version of this filing is also being filed under seal under separate cover.

Please do not hesitate to contact me if you have any questions in regard to the enclosed.

Highest regards,

/s/ Elaine S. Ryan

Elaine S. Ryan

Enclosures
cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.
Paul E. Pfeffer, Esq.
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220512009

May 5, 2022

Mr. Bernard Logan, Clerk
Virginia State Corporation Commission
c/o Document Control Center
1300 East Main Street
Richmond, VA 23219

Re: Case No. PUR-2022-00064

Dear Mr. Logan:

Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") hereby files with the Virginia State Corporation Commission ("Commission") its application to revise the fuel factor component of customer electric rates effective July 1, 2022 (the "Application"), pursuant to § 56-249.6 of the Code of Virginia. While in most years, this is a relatively routine filing, the dramatic increases in fuel prices as a result of the pandemic, inflation generally, and the war in Ukraine have created a significant fuel cost under-recovery and projections that fuel costs will remain elevated over the next year. The Company estimates that without steps to mitigate the effect of these costs, the fuel factor rate adjustment would result in an approximately 20% increase in the typical Dominion Energy Virginia residential customer's monthly bill for 1,000 kilowatt-hours of usage.

To avoid this outcome, the Company presents a voluntary mitigation proposal in the Application, including Two Year Mitigation and Three Year Mitigation alternatives. The Company recommends the latter option, which would reduce the impact to the typical residential customer to an approximately 12% bill increase due to the fuel factor rate adjustment. Taken together, the Three Year Mitigation proposal and separate rate revisions submitted to the Commission today would increase the typical residential customer's monthly bill by a net of approximately $9 or 7%, if approved as filed. This does not count a $1.98 savings from a filing previously approved by the Commission withdrawing a proposed increase for costs related to the Regional Greenhouse Gas Initiative. As always, the Company stands ready to work with customers to identify programs, services, and payment options that suit their particular needs.

The fuel factor rate is designed to recover purchased power costs and costs incurred to procure commodities, most notably natural gas and coal, needed to power the Company's traditional electric generating fleet and reliably serve its customers. The Company's current fuel factor rate, based on March 2021 commodity price projections, was set prior to significant increases in the price of purchased power, coal, and natural gas which have only been exacerbated by the war in Ukraine.

Differences between past projections and actual fuel costs are not unusual, and fuel factor rate revisions provide the opportunity to correct for any under- or over-recovery. However, the Company is mindful of the significant under-recovery which has accrued—the fuel deferral balance is expected to exceed $1 billion as of June 30, 2022. Additionally, current projections suggest that fuel commodity prices will remain at elevated levels for the medium term. This set of circumstances would ordinarily result in a significant customer impact from the fuel factor rate revision if the Commission were to approve a recovery rate over 12 months.

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The Application therefore presents alternatives to instead spread recovery over either two or three years. Both the Two Year Mitigation and Three Year Mitigation options would reduce the effect of the fuel factor rate revision on customer electric bills. Between these two alternatives, the Company recommends the Three Year Mitigation proposal because it provides for the smallest near-term rate increase, rate stability over the next several years, and greater flexibility in the event commodity markets have improved when the Commission revisits the fuel factor rate next year.

Dominion Energy Virginia is sensitive to any proposed electric rate increase, as evidenced by its recent motion to withdraw the proposed update to the rate adjustment clause associated with Regional Greenhouse Gas Initiative compliance (Rider RGGI). The Commission's approval of this motion last month avoided what the Company expected would have been a $1.98 increase to the typical residential customer's monthly bill. Today, the Company has proposed to cease customer billing for Rider RGGI effective July 1, 2022 and recover unrecovered RGGI-related costs through July 31, 2022 in its base rates. This will reduce the typical residential customer's monthly bill by approximately $2.39, subject to Commission approval.

The proposed revision to Rider T1, the Company's recovery mechanism for certain transmission-related costs, would save the typical residential customer another $3.69 per month in electricity costs if approved. Dominion Energy Virginia has also petitioned for a revision to Rider RBB, which enables cost recovery for projects undertaken in partnership with internet service providers to expand broadband access in Virginia. If approved, the Rider RBB update would increase the typical residential customer's monthly bill by $0.14. Thus, the Company anticipates that the net impact of other applications filed today with the Commission will help to offset the customer rate increase attributable to the fuel factor.

The Company is taking significant action to reduce customers' exposure to future fuel cost fluctuations. The ongoing diversification of its electric generating fleet—specifically, the addition of solar and offshore wind resources including the Coastal Virginia Offshore Wind project which have no associated fuel costs—will mitigate the risk of commodity price upheavals. Additionally, the Company will continue its practice of entering into market transactions that act as a hedge against future price uncertainty.

Dominion Energy Virginia believes this Application exemplifies its focus on ensuring that its safe and reliable electric service also remains affordable. With the Commission's approval, the Three Year Mitigation proposal described herein will help shield customers from what would otherwise be a significant fuel factor rate adjustment. The Company looks forward to a constructive and customer-beneficial outcome in this proceeding.

Sincerely,

Edward H. Baine

Edward H. Baine
President, Dominion Energy Virginia

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Dominion Energy®

Application, Direct Testimony, and Schedules of Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6

Volume 1 of 1
PUBLIC VERSION

Case No. PUR-2022-00064

Filed: May 5, 2022

220510086

Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6
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Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6
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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY	)	Case No. PUR-2022-00064
	)	
To revise its fuel factor pursuant to Va. Code § 56-249.6	)	
	)	

APPLICATION

Pursuant to § 56-249.6 of the Code of Virginia ("Va. Code"), Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), by counsel, files this application to revise its fuel factor effective July 1, 2022 (the "Application"). In support of its Application, the Company respectfully states the following:

1. Dominion Energy Virginia is a public service corporation organized under the laws of the Commonwealth of Virginia furnishing electric service to the public within its certificated service territory. The Company also supplies electric service to non-jurisdictional customers in Virginia and to the public in portions of North Carolina. The Company's electric system, consisting of facilities and associated facilities for the generation, transmission, and distribution of electric energy, is interconnected with the electric systems of neighboring utilities and is part of the interconnected network of electric systems serving the continental United States. Because of its operations in Virginia and North Carolina and its interconnections with other electric utilities, the Company engages in interstate commerce. The post office address of the Company is P.O. Box 26666, Richmond, Virginia 23261.

2. The facts supporting this Application are set forth in the accompanying testimony and exhibits of Gregory A. Workman, J. Scott Gaskill, Whitney W. Johnson, Katherine E.

220510089

Farmer, Dale E. Hinson, Tom A. Brookmire, Wesley A. Hudson, Ronnie T. Campbell, and Timothy P. Stuller.

3. The testimony and exhibits demonstrate that a revision to the Company's existing fuel factor rate is necessary to provide the Company with the appropriate level of fuel cost recovery pursuant to Va. Code § 56-249.6 over the period beginning July 1, 2022 through June 30, 2023.

4. The Company's total fuel factor, reflected in Fuel Charge Rider A, consists of both a current period and a prior period factor. As Company Witness Timothy P. Stuller discusses, for the July 1, 2022 through June 30, 2023 fuel year, the Company projects Virginia jurisdictional fuel expenses, including purchased power expenses, of approximately $2.278 billion, translating into a current period fuel factor rate of 3.0784 cents per kilowatt-hour ("¢/kWh"). The Company's projected June 30, 2022 fuel deferral balance is approximately $1.020 billion, translating into a prior period factor rate of 1.3784 ¢/kWh. Together, these components translate into a total proposed fuel factor rate of 4.4568 ¢/kWh for the period July 1, 2022 through June 30, 2023.

5. As explained by Company Witness Gregory A. Workman and others, the total projected fuel deferral balance attributable to the July 2021 – June 2022 is substantial, largely due to the increase in commodity prices over the past year. While significant, the under-recovery over the prior period was mitigated in part by the Company's comprehensive approach to fuel procurement and hedging, including the availability of a diverse generation portfolio, access to reliable fuel supply, and an effective commodity price hedging program. Comparing the July 2021 – March 2022 period with the similar period of July 2020 – March 2021, natural gas and coal fuel commodities experienced price increases of approximately 100% and 92%,

respectively, while the fuel component of the in-system generation output experienced only a 37% increase in $/MWh, as supported by Company Witness Dale E. Hinson.

6. While the Company is entitled to recovery of these prudently incurred fuel expenses on a prompt basis under Va. Code § 56-249.6, the Company recognizes the impact of such an increase in fuel rates on our customers. In order to mitigate the impact of an increase in the fuel factor rate on customers, the Company is voluntarily offering two alternative proposals to the full recovery rate, should the Commission find it to be in the public interest and so approve. Under the alternative proposals presented by Company Witness J. Scott Gaskill, the Company would waive its right to prompt recovery of the full deferral balance over the current period in favor of recovery of this balance equally over either two fuel periods ("Two Year Mitigation") or three fuel periods ("Three Year Mitigation"), at the Commission's discretion.

7. The Two Year Mitigation proposal would, if adopted, amortize the $1.020 billion projected June 30, 2022 fuel deferral balance for recovery equally over the fuel periods July 1, 2022 – June 30, 2023 *and* July 1, 2023 – June 30, 2024 (a total of 24 months). This would result in a prior period factor for the current fuel year of 0.6892 ¢/kWh and a total fuel factor rate of 3.7676 ¢/kWh for the current period—reducing the impact on the overall residential customer's monthly bill from 19.8% to 14.1%, compared to the full recovery rate during the current period.

8. The Three Year Mitigation proposal would, if adopted, amortize the $1.020 billion projected June 30, 2022 fuel deferral balance for recovery equally over the fuel periods July 1, 2022 – June 30, 2023, July 1, 2023 – June 30, 2024, and July 1, 2024 – June 30, 2025 (a total of 36 months). This would result in a prior period factor for the current fuel year of 0.4595 ¢/kWh and a total fuel factor rate of 3.5379 ¢/kWh for the current period—reducing the impact on the overall bill for the typical residential customer from 19.8% to 12.2%, compared to the full recovery rate during the current period. This represents a further 0.2297 ¢/kWh rate reduction,

or approximately $2.30 per month bill savings for a residential customer, over the Two Year Mitigation.

9. The Company believes that its voluntary fuel factor mitigation proposals recognize the interests of customers in avoiding abrupt rate increases, as referenced in Va. Code § 56-249.6, and are consistent with the public interest. While either mitigation proposal is preferable to the full recovery rate, the Three Year Mitigation offers the smallest near-term fuel rate increase, promotes rate stability across the next several years, and offers the Commission flexibility next year if circumstances around commodity markets have improved. For these reasons, the Company requests that the Commission approve the Three Year Mitigation proposal and set a fuel rate of 3.5379 ¢/kWh.

10. Further, to the extent that the Commission directs implementation of an interim fuel rate for usage on and after July 1, 2022, the Company requests that the proposed fuel factor rate of 3.5379 ¢/kWh based on the Three Year Mitigation proposal be implemented as the interim rate.

11. Concurrent with this filing, the Company has also filed a petition to suspend its rate adjustment clause designated Rider RGGI effective July 1, 2022, which, if approved by the Commission, would lower the typical residential bill by $2.39 per month at the same time the fuel factor increase would take place. Additionally, the Company has filed its annual update to Rider T1, which, if approved would result in a reduction in the typical residential customer bill of approximately $3.69 per month. Taken as a whole—the Three Year Mitigation, suspension of Rider RGGI, and the Rider T1 reduction—the increase to a typical residential customer bill is approximately $9.00 per month. While the Company does not take any such rate increase lightly, it is mindful of the impact to its customers and is taking meaningful steps to limit the impact felt from the current commodity market pressures.

12. In connection with this Application, the Company is also seeking approval of an accounting change as it relates to the funding of the fuel factor for customers taking service under the approved market-based rate ("MBR") schedules, Rate Schedule MBR, Rate Schedule MBR-GS-3, Rate Schedule MBR-GS-4, and the SCR Rate Schedule (collectively, the "MBR Customers"), to more timely align the timing of the fuel expense incurred by the Company and the revenues received through the market-based charges from these customers as presented by Company Witness Gaskill. This change holds both MBR and non-MBR customers harmless and is intended to resolve the timing mismatch between revenue and fuel expense that exists for customers taking service on these voluntary rate schedules.

13. Specifically, the Company is proposing a going-forward accounting change with respect to MBR revenues such that it will fund the Company's *actual* average system fuel costs on a month-by-month basis instead of the approved fuel rate. By making this accounting change, there will be better alignment between MBR revenue, and the fuel costs incurred to serve these customers. In other words, MBR-customer revenues would fund their share of actual fuel costs on a real-time basis instead of contributing to an over- or under-recovery of fuel costs. MBR revenue would be removed from the fuel deferral process. The Company proposes that this change take effect on July 1, 2022.

14. Fuel Charge Rider A specifies how MBR revenues are treated with respect to the fuel deferral. Therefore, Company Witness Timothy P. Stuller presents the revised Fuel Charge Rider A tariff sheet to incorporate this change.

WHEREFORE, Virginia Electric and Power Company respectfully files the proposed fuel factor of 3.5379 ¢/kWh, as set out herein, effective for usage on and after July 1, 2022, and requests that the Commission approve the revised Fuel Charge Rider A tariff incorporating the proposed accounting change for MBR customers effective July 1, 2022.

220510089

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

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Counsel for Virginia Electric and Power Company

May 5, 2022

Attachment 70

ENERGY + ENVIRONMENT

THE BULLETIN

Regulators approve Dominion bill increase for rising fuel costs; Appalachian Power also seeking hike

BY: **CHARLIE PAULLIN** - SEPTEMBER 19, 2022 12:01 AM

Transmission lines in Louisa County. (Ned Oliver/ Virginia Mercury)

Dominion customers will see their monthly electricity bills increase as a result of rising fuel costs, with Appalachian Power Company seeking similar hikes on the same grounds.

On Friday, the State Corporation Commission approved the increase for Dominion, which went into effect provisionally on July 1. According to

estimates, the average residential customer, defined as a household using 1,000 kilowatt-hours of electricity per month, will see their monthly bill increase by $14.93.

In its final order, the commission said it was aware "of the ongoing rise in gas prices, inflation, and other economic pressures that are impacting all utility customers."

"We are sensitive to the effects of rate increases, especially in times such as these," regulators wrote. "The commission, however, must follow the laws applicable to this case, as well as the findings of fact supported by the evidence in the record. This is what we have done herein."

Dominion applied for the increase in its fuel factor, the rate levied on customers to cover the costs of purchasing fuel for power plants, in May, citing increases in fuel costs linked to the COVID-19 pandemic, inflation and the ongoing war in Ukraine.

The company sought to minimize the impact on customers by proposing to spread its recovery of the additional $1 billion in fuel costs over three years, a recommendation the commission accepted.

Coinciding with the approval, Appalachian Power said Friday it intends to seek a similar rate increase that could raise monthly bills for the average residential customer by about $20.

The company is seeking to spread the recovery over a two year period.

"We recognize these are challenging financial times for many people and families," said Chris Beam, Appalachian Power's president and chief operating officer in a statement. "We strive each day to keep fuel costs as low as possible, continuously monitoring energy markets for opportunities to purchase fuel and energy at prices that are advantageous to customers."

The utility also said that its growing use of renewable energies such as solar and wind "is another step in reducing fuel costs."

"As Appalachian Power adds more renewables, there is less need for coal and natural gas to generate power," the company noted in its Friday statement.

Appalachian said that about 6% of the power used by the company's customers is generated by renewables.

Under the 2020 Virginia Clean Economy Act, both Appalachian and Dominion are required to decarbonize by 2050.

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CHARLIE PAULLIN

Charles Paullin covers energy and environment for the Mercury. He previously worked for Northern Virginia Daily in the Northern Shenandoah Valley and for the New Britain Herald in central Connecticut. An Alexandria native, Charles graduated from the University of Hartford initially wanting to cover sports. He's received several Virginia Press Association awards for his coverage of crime, local government and state politics. Catch him in nature experiencing all the outdoors has to offer, and contact him at cpaullin@virginiamercury.com.

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May 10, 2022

Attachment 71

ENERGY + ENVIRONMENT

Dominion asks to halt ratepayer charge for carbon market

Critics say request to recoup remaining costs through base rates shows extra charge was never needed

BY: **SARAH VOGELSONG** - MAY 6, 2022 12:04 AM

Dominion Energy offices in Richmond, Va. (Parker Michels-Boyce/ For The Virginia Mercury)

Dominion Energy is asking state regulators to stop charging customers on their monthly bill for the utility's participation in a carbon market in anticipation of Gov. Glenn Youngkin's plans to withdraw Virginia from the Regional Greenhouse Gas Initiative.

Suspending the charge, known as Rider RGGI, "will provide an immediate, material reduction to customer bills," the utility wrote in a filing with the State Corporation Commission Thursday.

The move comes as Dominion is is looking for ways to offset soaring fuel costs that could increase customer bills by between 7 and 20 percent.

But critics said the utility's plan to get rid of the rider appeared to be more of a political move and that its decision to recover the remaining RGGI costs through base rates, which make up the largest portion of a customer's bill, demonstrates that Dominion never needed to impose the extra charge for market participation at all.

"They are conceding that they could have been complying with RGGI all along without raising rates but instead simply chose to rate rates just because they could," said Will Cleveland, an attorney with the Southern Environmental Law Center.

In Virginia, Dominion customers' bills are made up of three components: base rates, fuel costs and rate adjustment clauses, generally referred to as riders. The riders are intended to cover the costs of specific projects like coal ash cleanup or various generation resources.

Dominion has calculated that the RGGI rider adds $2.39 to the average residential customer's monthly bill. If approved, suspension of the rider would eliminate that charge beginning July 1.

Under state law, Dominion was allowed but not required to recover RGGI costs through a rider.

The utility said in its Thursday filing that it has recouped approximately $82 million in RGGI compliance costs through the rider and that approximately $178 million will remain to be recovered through base rates.

Dominion said recovering the remaining amount through base rates "will prevent future incremental rate increases."

"The company believes that these actions are particularly in the public interest given current geopolitical and market conditions beyond its control which are driving increases in the costs to be recovered from customers of fuel commodities," the utility wrote.

Base rates are reviewed by the State Corporation Commission every three years. If regulators find that the company has not earned enough to cover its expenses and an allowable profit, they can order that base rates be raised. If they find Dominion has overearned, they can order the utility to refund part of the excess earnings.

Cleveland said that the remaining RGGI costs could potentially contribute to Dominion requesting a higher base rate at the next triennial review, which is slated to occur in 2024.

“That will be one of the many line items balanced to determine whether Dominion’s revenues exceeded its costs,” he said.

The Mercury asked Dominion how it is able to absorb the remaining RGGI costs into its existing base rates and whether it could have recouped them that way all along. Dominion General Manager of Regulatory Affairs Scott Gaskill said in an email that because of rising commodity prices, the utility has “been looking at ways to mitigate the near-term customer impact” and pointed out that Dominion this January asked regulators to cancel an expected increase to the RGGI rider.

“Since we expect RGGI costs to end soon, it made sense to eliminate this rider at this time and move to base rates as a one-time expense,” he wrote.

Del. Tony Wilt, R-Rockingham, who unsuccessfully carried a bill during the last legislative session that among other provisions would have given regulators more leeway to decide if costs should be recovered through riders or base rates, said Dominion’s request “demonstrates the importance of ensuring our state regulators have the authority to review, assess and analyze rate-making policies in the best interests of customers.”

Dominion also stated in its filing that if Virginia does not withdraw from RGGI by the end of July, it reserves the right to ask regulators to resume charging customers for participation costs.

Coal fired units at Dominion Energy's Chesterfield Power Station are scheduled to close. (Ryan M. Kelly/ For the Virginia Mercury)

A simmering conflict

While conflict over RGGI has been simmering since Youngkin announced last December that he intended to pull Virginia out of the market, the administration is expected to begin attempting to roll back regulations governing state participation this summer.

In an executive order issued on his inauguration day, Youngkin ordered the Virginia Department of Environmental Quality to develop an emergency regulation to repeal existing rules for RGGI participation. That regulation will need to be approved by the Virginia State Air Pollution Control Board.

In its Thursday filing, Dominion said it expects the emergency regulation to go into effect as early as July. That time frame is in line with a statement made by DEQ Director Mike Rolband to the air board in April that the regulatory process was expected to start in the third quarter of the year.

An air board action isn't likely to be the end of the fight. Several environmental groups, including the Southern Environmental Law Center, have contended that legislation is necessary to pull Virginia out of the carbon market.

Republicans proposed such legislation during the 2022 session, but it failed in the Democrat-controlled Senate.

"We've said before and we maintain that the 2020 law requires Virginia to participate, and whether acting through an executive order or acting through the air board, you can't simply repeal a regulation and still be in compliance with that law," said SELC attorney Nate Benforado.

Dominion has been critical of Virginia's participation in RGGI, largely on the grounds of customer expense, particularly given the utility's investment in renewables required under the Virginia Clean Economy Act.

"We're concerned that Virginia's linkage to the RGGI program … would result in a financial burden on customers with no real mitigation of greenhouse gas emissions regionally," said Dominion Chief Financial Officer Jim Chapman on an investor call Thursday.

SCC Judge Judith Jagdmann has also questioned whether Dominion customers are paying duplicative costs to both participate in RGGI and comply with the Virginia Clean Economy Act.

Other energy analysts, however, have disputed the characterization of RGGI as ineffective at reducing carbon emissions, pointing to steep emissions declines in participating states compared to non-participating ones and changes in utilities' decision-making about which power plants it decides to run to power the grid. They also point out that roughly a quarter of

Virginia's carbon emissions governed by RGGI come from non-regulated power producers that otherwise have no legal requirement to reduce emissions.

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SARAH VOGELSONG

Sarah is Editor-in-Chief of the Mercury and previously its environment and energy reporter. She has worked for multiple Virginia and regional publications, including Chesapeake Bay Journal, The Progress-Index and The Caroline Progress. Her reporting has won awards from groups such as the Society of Environmental Journalists and Virginia Press Association, and she is an alumna of the Columbia Energy Journalism Initiative and Metcalf Institute Science Immersion Workshop for Journalists. She is a graduate of the College of William and Mary. Contact her at svogelsong@virginiamercury.com

MORE FROM AUTHOR

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Attachment 72

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

Case Number (if already assigned)	PUR-2022-00070
Case Name (if known)	Petition of Virginia Electric and Power Company, For revision and reinstatement of rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia
Document Type	EXPE
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December 14, 2022

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Petition of Virginia Electric and Power Company, For revision and reinstatement of rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia
Case No. PUR-2022-00070

Dear Mr. Logan:

Please find enclosed for electronic filing Virginia Electric and Power Company's *Petition, Direct Testimony, and Schedules* in the above-captioned proceeding.

Please do not hesitate to contact me if you have any questions in regard to this filing.

Highest regards,

/s/ Elaine S. Ryan

Elaine S. Ryan

enc.

cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.
Paul E. Pfeffer, Esq.
Lisa R. Crabtree, Esq.
Timothy D. Patterson, Esq.
Nicole M. Allaband, Esq.

2022-0070-122

Petition, Direct Testimony, and Schedules of Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

For revision and reinstatement of rate adjustment clause: Rider RGGI under § 56-585.1 A 5 e of the Code of Virginia

Volume 1 of 1

Case No. PUR-2022-00070

Filed: December 14, 2022

Petition of Virginia Electric and Power Company, For revision and reinstatement of rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia
Case No. PUR-2022-00070

2022-0070

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY	)	
	)	Case No. PUR-2022-00070
For revision and reinstatement of rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia	)	

PETITION OF VIRGINIA ELECTRIC AND POWER COMPANY

Pursuant to § 56-585.1 A 5 e ("Subsection A 5 e") of the Code of Virginia ("Va. Code"), Ordering Paragraph (5) of the State Corporation Commission of Virginia's ("Commission") Order Granting Petition in this proceeding, Ordering Paragraph (5) of the Commission's Order Granting Motion in Case No. PUR-2021-00281,[1] and the Commission's Rules Governing Utility Rate Applications and Annual Informational Filings of Investor-Owned Electric Utilities (the "Rate Case Rules"),[2] Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), by counsel, hereby submits this petition to update and reinstate its rate adjustment clause ("RAC"), designated Rider RGGI, to recover projected and actual costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide ("CO_2") emissions, a program in which the Company is required to participate. In support of its petition ("Petition"), the Company respectfully shows as follows:

---

[1] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia,* Case No. PUR-2021-00281, Order Granting Motion at Ordering Paragraph (5) (Apr. 1, 2022) ("2021 Annual Update").

[2] 20 VAC 5-204-10, *et seq.*

2021-00034122

GENERAL INFORMATION

1. Dominion Energy Virginia is a public service corporation organized under the laws of the Commonwealth of Virginia furnishing electric service to the public within its certificated service territory. The Company also supplies electric service to non-jurisdictional customers in Virginia and to the public in portions of North Carolina. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation. The Company is also a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. The Company is an operating subsidiary of Dominion Energy, Inc.

2. The Company's address is:

Virginia Electric and Power Company
120 Tredegar Street
Richmond, Virginia 23219

3. The names, addresses, and telephone numbers of the attorneys for the Company are:

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BACKGROUND

4. Initiated in 2009, RGGI is the first mandatory market-based program in the United States to reduce greenhouse gas emissions. RGGI is a collaborative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia to cap and reduce CO_2 emissions from the power sector. CO_2 allowances are created and sold by RGGI member states in quarterly regional auctions. Virginia joined RGGI in 2021.

5. The Company owns regulated emissions sources, so it must comply with RGGI by obtaining and surrendering a CO_2 emission for every short ton of CO_2 emitted during a control period.

6. Va. Code § 56-585.1 A 5 e permits cost recovery related to compliance with RGGI and establishes the applicable standard of review:

> A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of . . . [p]rojected and actual costs of projects that the Commission finds to be necessary . . . to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the costs of allowances purchased through a market-based trading program for carbon dioxide emissions. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations.

7. On August 4, 2021, in Case No. PUR-2020-00169 ("2020 Rider RGGI Proceeding"), the Commission issued its Order Approving Rate Adjustment Clause ("2020 Rider RGGI Order"), approving Rider RGGI to be effective for usage on and after September 1, 2021.[3]

---

[3] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No PUR-2020-00169, Order Approving Rate Adjustment Clause at 11 (Aug. 4, 2021). The Supreme Court of Virginia affirmed the Commission's Final Order on

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8. On December 6, 2021, the Company filed its first Rider RGGI annual update in Case No. PUR-2021-00281.[4] Following an announcement from then-Governor-elect Glenn Youngkin on December 8, 2021, that he intended to withdraw Virginia from RGGI, on January 10, 2022, the Company moved the Commission to withdraw its 2021 Annual Update. By its Order on April 1, 2022, the Commission granted the Company's motion, and, among other things, directed the Company to file an update to Rider RGGI "on or before January 1, 2023."[5]

9. Following further developments concerning Virginia's participation in RGGI, on May 5, 2022, the Company filed a petition in the instant proceeding requesting the Commission issue an order (i) suspending the Rider RGGI rate approved in Case No. PUR-2020-00169; (ii) resetting the Rider RGGI rate to $0.000000 per kilowatt-hour ("kWh") effective July 1, 2022; and (iii) approving the Company's election to recover RGGI compliance costs incurred through July 31, 2022, but not recovered through Rider RGGI, through its base rates for generation services in the period in which they were incurred.[6] By its Order Granting Petition issued on June 15, 2022 in this docket, the Commission granted the Petition and directed that the docket remain open for future proceedings, including but not limited to the actual cost true-up proceeding to review incurred allowance costs that have been recovered through Rider RGGI, as required in the 2020 Rider RGGI Order.

October 27, 2022. *Appalachian Voices v. State Corp. Comm'n*, Record No. 220130, 2022 WL 14988165 (Oct. 27, 2022).

[4] 2021 Annual Update, Petition at *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00281, Petition (Dec. 6, 2021).

[5] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00281, Order Granting Motion at Ordering Paragraph (5) (Apr. 1, 2022).

[6] The Company further reserved its right under Subsection A 5 e to petition for resumption of Rider RGGI and recovery of any costs incurred to meet its compliance obligations on or after August 1, 2022, as may be approved by the Commission, and requested that the Commission hold this docket open for further proceedings as future events concerning the Commonwealth's participation in RGGI develop.

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RIDER RGGI

10. In accordance with the Commission's 2020 Rider RGGI Order and 2022 Order Granting Petition, the Company files this Petition to account for allowance costs incurred and recovered through Rider RGGI prior to the July 1, 2022 suspension. Additionally, the Company seeks to reinstate Rider RGGI to recover deferred RGGI compliance costs incurred after July 31, 2022, and those projected to occur over the period of September 1, 2023 through August 31, 2024 (the "Rate Year"). For purposes of this proceeding, the Company has assumed that Virginia will withdraw from RGGI on December 31, 2023, and accordingly has not projected any RGGI-related compliance costs to be incurred after that date.[7]

11. From August 1, 2022, through December 31, 2023, the Company will require approximately 31 million CO_2 allowances to cover CO_2 emissions from its Virginia-based generation fleet. Approximately 7 million of these CO_2 allowances are projected to be incurred during the Rate Year.

12. Generally, to meet its obligations under RGGI, the Company is following a programmatic approach by purchasing most of the required allowances in the quarterly auctions and using the secondary market to fill any auction deficiencies. More specifically, Dominion Energy Virginia plans to acquire approximately 25% of the forecasted annual allowance requirement in each of the quarterly auctions. If the Company fails to secure approximately 25% in an auction, the Company will look to purchase allowances in the secondary market. The Company's compliance strategy is not based on any price outlook. Instead, the Company intends to continue to follow a programmatic, auction-based approach to compliance. However, the

[7] On December 7, 2022, the Virginia Air Pollution Control Board advanced a proposal to repeal the regulations establishing RGGI pursuant to the Virginia Administrative Process Act, with a targeted repeal date of December 31, 2023.

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Company may adjust its compliance strategy as needed to adapt to changes in the structure of the RGGI program.

13. The Company has assumed a weighted average price of $13.52 per allowance. This assumption is based on December ICE futures contracts for 2022 and 2023.

14. Company Witness Paul M. McLeod details the Company's proposal to recover total RGGI compliance costs incurred since Virginia joined RGGI in 2021 through the expected exit date in December 2023. Specifically, Company Witness McLeod supports a total Virginia jurisdictional revenue requirement of $640 million for this period in the aggregate. For the period prior to August 1, 2022, the total revenue requirement was $267 million on a Virginia jurisdictional basis. The Company recovered $84 million of the $267 million through the initial Rider RGGI in effect from January 1, 2022 through June 30, 2022. The remaining amount of $183 million is being recovered through base rates in effect as incurred. For the period from August 1, 2022 through December 31, 2023, the projected revenue requirement is $373 million on a Virginia jurisdictional basis, which the Company is proposing to recover during the Rate Year through the reinstated Rider RGGI requested in this proceeding.

15. The Company's RAC revenue requirement in this proceeding includes the Projected Cost Recovery Factor and the Actual Cost True-Up Factor. The Projected Cost Recovery Factor reflects the revenue requirement necessary for recovery of amortization expense for CO_2 allowances as well as projected financing costs on the unamortized purchased CO_2 allowance balance. Additionally, the Projected Cost Recovery Factor includes the amortization of deferred costs, including financing costs, incurred prior to the Rate Year. The Actual Cost True-Up Factor will recover from, or credit to, customers any under- or over-recovery of costs from the most recently completed calendar year. No Actual Cost True-Up Factor is included in

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this proceeding as all differences between costs incurred and amounts recovered through Rider RGGI through July 31, 2022, will be recovered through base rates pursuant to the Order Granting Petition. It is anticipated that any true-up for calendar year 2022 will be included in a 2023 update filing for implementation during the September 1, 2024 to August 31, 2025 rate year.

16. The total revenue requirement requested for recovery in this Rider RGGI Petition for the Rate Year beginning September 1, 2023, is $373,214,000.

17. For purposes of this Petition, and consistent with the Commission's November 18, 2021 Final Order in the Company's triennial review proceeding in Case No. PUR-2021-00058,[8] the Company is utilizing the approved return on common equity ("ROE") of 9.35% for the period subsequent to the date of that Final Order. For the time periods prior to the Final Order in that case, the Company is utilizing a ROE of 9.2%, as approved by the Commission in Case No. PUR-2019-00050.[9]

18. The implementation of the proposed Rider RGGI on September 1, 2023, will increase the typical residential customer's monthly bill, based on 1,000 kWh per month, by $4.64.[10]

RGGI COMPLIANCE AND RPS DEVELOPMENT PLAN MODELING

19. In the 2020 Rider RGGI Order, the Commission directed the Company to "include in future Rider RGGI filings an analysis of how its RGGI compliance corresponds to its

[8] *Application of Virginia Electric and Power Company For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUR-2021-00058, Final Order (Nov. 18, 2021).
[9] *Application of Virginia Electric and Power Company For the determination of the fair rate of return on common equity pursuant to § 56-585.1:1 C of the Code of Virginia*, Case No. PUR-2019-00050, Final Order (Nov. 21, 2019).
[10] As of the date of this filing, the Rider RGGI rate is $0.000000 per kWh.

RPS plan filings."[11] The Company has prepared this analysis and included it as Exhibit 1 to this Petition. Exhibit 1 is sponsored by Company Witness Jeffrey D. Matzen.

SUPPORTING TESTIMONY AND FILING SCHEDULES 3, 4, 5, 8, AND 46

20. The Company's Petition is supported by the pre-filed direct testimonies of Company Witnesses George E. Hitch, Jeffrey D. Matzen, Paul M. McLeod, and C. Alan Givens.

21. Section 60 of the Rate Case Rules provides that an application filed pursuant to Subsection A 5 "shall include Schedule 46 as identified and described in 20 VAC 5-204-90, and which shall be submitted with the utility's direct testimony. Additionally, petitions requiring an overall cost of capital shall include Schedules 3, 4, 5, and 8."

22. With this Petition, the Company files the following Filing Schedules:

a. Filing Schedules 3 through 5 and Filing Schedule 8, sponsored by Company Witness McLeod, provide information regarding the Company's cost of capital.

b. Filing Schedule 46A, consisting of Statements 1 and 2, is co-sponsored by Company Witnesses Hitch and Matzen. Filing Schedule 46A, Statement 1, provides projected and actual costs associated with Rider RGGI, while Filing Schedule 46A, Statement 2, provides documentation supporting those costs.

c. Filing Schedule 46B, consisting of Statements 1 and 2, is sponsored by Company Witness McLeod. Filing Schedule 46B, Statement 1, addresses the estimated annual revenue requirement for the Rate Year. Given the assumption that the Commonwealth will withdraw from RGGI on December 31, 2023, and that there will be no further compliance costs incurred after that date, Filing Schedule 46B, Statement 2 notes that there is no long-term revenue requirement calculation included with this filing.

d. Filing Schedule 46C, consisting of Statements 1 and 2, is sponsored by Company Witness Givens. Filing Schedule 46C, Statement 1, provides the annual revenue requirement for Rider RGGI by class. Filing Schedule 46C, Statement 2, addresses the Company's methodology for allocating the Rider RGGI revenue requirement.

[11] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No PUR-2020-00169, Order Approving Rate Adjustment Clause at 11 (Aug. 4, 2021).

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COMPLIANCE WITH RULE 10 OF THE RATE CASE RULES

23. The Company's Petition complies with the requirements contained in Rule 10 of the Rate Case Rules.

24. In accordance with Rule 10 A, the Company filed with the Commission its notice of intent to file this Petition on September 29, 2022, and provided that notice to those listed in Rule 10 J 1, as required by that subsection.

25. The Company has included all information required by Rule 10 B in its Petition, including a table of contents, direct testimonies with one-page summaries, and properly labeled exhibits and schedules.

26. In accordance with Rule 10 H, the Company will make a searchable PDF version of the Petition, direct testimonies, and Filing Schedules available via the eRoom contemporaneously with this filing, with immediate access available to (i) Commission Staff, including identified members of the Divisions of Utility Accounting and Financing and Public Utility Regulation; and (ii) identified members of the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel").[12] Also in accordance with Rule 10 H, the Company will make electronic spreadsheets supporting the schedules that contain calculations available via an eRoom contemporaneously with this filing, with immediate access available to Commission Staff.

CONCLUSION

WHEREFORE, Dominion Energy Virginia respectfully requests that the Commission (i) reinstate Rider RGGI effective September 1, 2023; (ii) approve the proposed revenue

[12] Rule 10 J 3 requires the Company to provide a copy of the complete public version of the filing to Consumer Counsel at the same time it is filed with the Commission. As noted, pursuant to Rule 10 H, the Company will make a searchable PDF version of the petition, direct testimonies, and Filing Schedules available via an eRoom contemporaneously with this filing with immediate access available to Consumer Counsel.

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requirement, cost allocation, rate design, and accounting treatment for Rider RGGI for the Rate Year September 1, 2023 through August 31, 2024; and (iii) grant such other relief as deemed appropriate and necessary.

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

By: */s/ Elaine S. Ryan*
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Counsel for Virginia Electric and Power Company

December 14, 2022

Exhibit 1

2022-00169

Dominion Energy Virginia's RGGI Compliance and RPS Development Plan Modeling

In its Order Approving Rate Adjustment Clause in Case No. PUR-2020-00169, the Commission directed the Company "to include in future Rider RGGI filings an analysis of how its RGGI compliance corresponds to its RPS plan filings."[1] This document provides that analysis.

I. Background – VCEA

The Virginia Clean Economy Act ("VCEA")—Senate Bill No. 851 and House Bill No. 1526 from the 2020 Regular Session of the Virginia General Assembly—became law in the Commonwealth effective July 1, 2020. Relevant to this proceeding, the VCEA (i) requires the development of renewable energy generation resources; (ii) requires the development of energy storage resources; (iii) requires the submission of an annual plan to meet the development targets; and (iv) institutes a mandatory renewable energy portfolio standard program ("RPS Program").

Under Va. Code § 56-585.5 D 4, the Company must submit an annual plan outlining how it intends to meet the renewable energy generation and energy storage development targets. This annual filing must contain any request for approval to construct or purchase solar, energy storage, or onshore wind generation under Va. Code § 56-580 D, as well as any associated requests related to cost recovery of such facilities under Va. Code § 56-585.1 A 6. The Commission must determine whether such annual filings are reasonable and prudent, giving due consideration to certain factors: (i) the RPS and carbon dioxide reduction requirements of the VCEA, (ii) the promotion of new renewable generation and energy storage resources within the Commonwealth and associated economic development, and (iii) fuel savings projected to be achieved by the plan.

II. Background – RPS Development Plan

Dominion Energy Virginia submitted its first RPS Development Plan in Case No. PUR-2020-00134, which the Commission approved as reasonable and prudent on April 30, 2021. The Commission approved the Company's 2021 RPS Development Plan as reasonable and prudent on March 15, 2022 in Case No. PUR-2021-00146.

Dominion Energy Virginia submitted its 2022 RPS Development Plan on October 14, 2022 in Case No. PUR-2022-00124. In that filing, the Company affirms that the 2022 RPS Development Plan is consistent with Alternative Plan B from the Company's 2022 update to its Integrated Resource Plan ("2022 IRP Update") filed on September 1, 2022 in Case No. PUR-2022-00147, which is described in more detail in Part IV, below. The Company further affirms

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[1] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Order Approving Rate Adjustment Clause at 11 (Aug. 4, 2021).

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that the modeling inputs and assumptions are consistent between the 2022 IRP Update and the 2022 RPS Development Plan. The 2022 RPS Development Plan will (i) support RPS Program compliance; (ii) support carbon dioxide ("CO_2") reductions in the Commonwealth; (iii) promote new renewable energy generation and energy storage resources in the Commonwealth and the associated economic development; and (iv) result in fuel savings while maintaining reliability.

III. Background – Rider RGGI

On November 9, 2020, in Case No. PUR-2020-00169, the Company filed for approval of a rate adjustment clause, designated Rider RGGI, under Va. Code § 56-585.1 A 5 e to recover projected and actual costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for CO_2 emissions, a program in which the Company is required to participate. In its August 4, 2021 Order Approving Rate Adjustment Clause and its November 17, 2021 Order on Reconsideration, the Commission approved Rider RGGI, finding that the Company's compliance approach is a reasonable way to manage operational facilities in the short-term and that the costs requested in that proceeding complied with the statutory standard.[2]

On December 6, 2021, the Company filed its first Rider RGGI annual update in Case No. PUR-2021-00281.[3] Following an announcement from then-Governor-elect Glenn Youngkin on December 8, 2021, that he intended to withdraw Virginia from RGGI, on January 10, 2022, the Company moved the Commission to withdraw its 2021 Annual Update. By its Order on April 1, 2022, the Commission granted the Company's motion, and, among other things, directed the Company to file an update to Rider RGGI "on or before January 1, 2023."[4]

Following further developments concerning Virginia's participation in RGGI, on May 5, 2022, the Company filed a petition in the instant proceeding requesting the Commission issue an order (i) suspending the Rider RGGI rate approved in Case No. PUR-2020-00169; (ii) resetting the Rider RGGI rate to $0.000000 per kilowatt-hour ("kWh") effective July 1, 2022; and (iii) approving the Company's election to recover RGGI compliance costs incurred through July 31, 2022, but not recovered through Rider RGGI, through its base rates for generation services in the period in which they were incurred.[5] By its Order Granting Petition issued on June 15, 2022 in this docket, the Commission granted the Petition and directed that the docket remain open for

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[2] The Supreme Court of Virginia affirmed the Commission's Final Order on October 27, 2022. *Appalachian Voices v. State Corp. Comm'n*, Record No. 220130, 2022 WL 14988165 (Oct. 27, 2022).

[3] 2021 Annual Update, Petition at *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00281, Petition (Dec. 6, 2021).

[4] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00281, Order Granting Motion at Ordering Paragraph (5) (Apr. 1, 2022).

[5] The Company further reserved its right under Subsection A 5 e to petition for resumption of Rider RGGI and recovery of any costs incurred to meet its compliance obligations on or after August 1, 2022, as may be approved by the Commission, and requested that the Commission hold this docket open for further proceedings as future events concerning the Commonwealth's participation in RGGI develop.

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future proceedings, including but not limited to the actual cost true-up proceeding to review incurred allowance costs that have been recovered through Rider RGGI, as required in the 2020 Rider RGGI Order.

IV. Analysis

In the 2022 IRP Update, the Company presented five alternative plans ("Alternative Plans"). Alternative Plan A presents a least-cost plan that meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA. The Company presented this Alternative Plan for cost comparison purposes only in compliance with prior Commission orders. Notably, Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. By contrast, Alternative Plan B is consistent with the 2022 RPS Development Plan.[6] Plan B complies with the development targets of the VCEA and includes significant buildout of renewable resources coupled with considerable CO_2 emissions reductions.

Using PLEXOS, the Company models reliability at a system level by ensuring that sufficient resources are available to meet customer load based on the hourly profile of both load and resources. Because the Company is a member of PJM Interconnection, LLC ("PJM"), PLEXOS has the option to fill any deficits in any specific hour with market purchases. PLEXOS does not currently show any reliability issues through 2036 based on the modeling completed for the 2022 IRP Update, as incorporated into the 2022 RPS Development Plan proceeding.

Importantly for future planning purposes, however, the Company must take other factors into account to ensure reliability in the long term. For example, if other states pursue the same clean energy future as the Company, resulting in significant volumes of intermittent resources with the same operational profiles as the Company's, the Company may not be able to fill any deficits in specific hours with market purchases. Separate from system level planning, planning at the more granular nodal and feeder level is also needed to ensure reliability, which is completed by the Company's transmission and distribution teams. It is at the nodal level that the system reliability and stability may become a concern based on physical transmission and distribution constraints. The Company continues to actively plan for these potential issues, and will continue to do so as the Company transitions to a cleaner fleet as envisioned by the Commonwealth, the Company, and its customers. See the Company's 2022 IRP Update for a further discussion of the Company's evaluation of seasonal concerns and a status of the Company's long-term transmission reliability analyses.

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[6] Alternative Plan C differs from Plan B in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Alternative Plan D uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045, resulting in zero CO_2 emissions from the Company's fleet beginning in 2046. Alternative Plan E is like Plan D in retiring all Company-owned carbon-emitting generation by the end of 2045, but all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind and energy storage resources in Virginia established through the VCEA.

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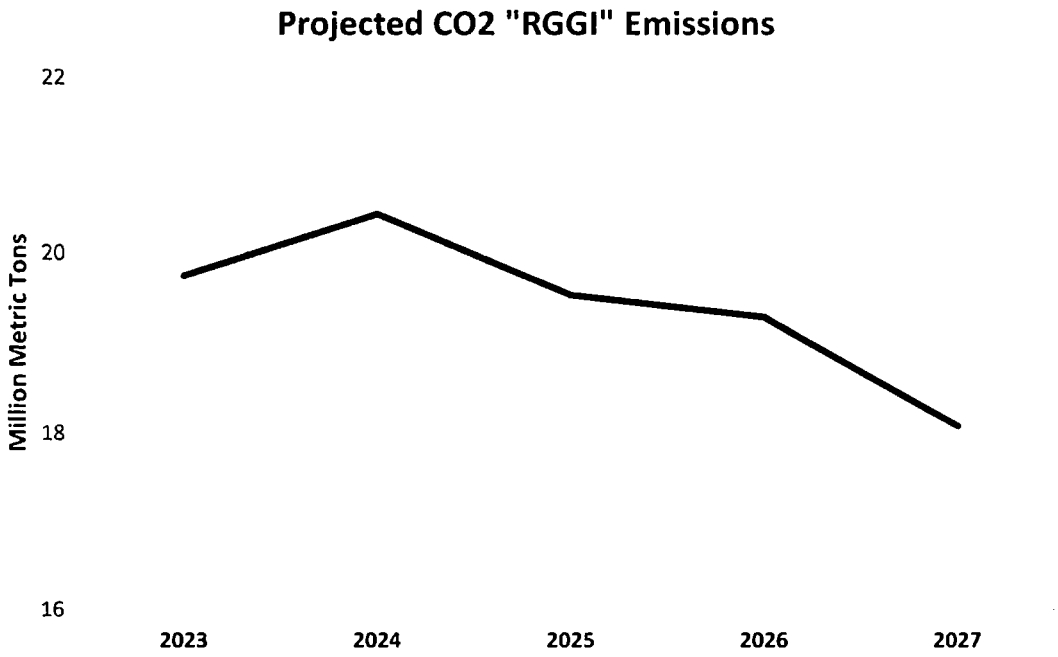
The RPS Development Plan will support CO_2 reductions in the Commonwealth through the development of a significant amount of CO_2-free generation resources that will displace both market purchases and output from other traditional Company-owned generation units that emit CO_2 as a byproduct of combustion. Figure 1 below shows the projected CO_2 output from the Company's fleet in the Commonwealth through 2027. Figure 1 reflects the RGGI Model, which includes the RPS Development Plan, the tentative retirements of certain generation units as indicated in Alternative Plan B of the Company's 2022 IRP Update, and the assumption that Virginia will exit RGGI on December 31, 2023, as further described below.

Figure 1: RGGI Model



To date, the Company has followed the RPS Development Plan in developing CO_2-free generation. The Company has also retired certain generation units consistent with the RPS and IRP plans. The Company further endeavors to minimize customer cost while maintaining reliability through prudent dispatch of dispatchable units. As a member of PJM, the Company offers units for dispatch with accurate cost estimates that include RGGI compliance costs. The PJM market clearing process dispatches the fleet economically, subject to constraints.

For determining forward RGGI allowance requirements for this proceeding, the Company has projected CO_2 emissions by modeling the system dispatch using assumptions that are generally consistent with both the 2022 IRP Update (Alternative Plan B) and the 2022 RPS Development Plan. The modeling has assumed a capacity factor for existing and future solar

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resources of 22.5%, which is the three-year average of the Company's solar tracking facilities in Virginia, and used an updated load forecast and commodity price forecast. Additionally, the RGGI Model has adjusted for the Company's revised assumption that Virginia will withdraw from RGGI at the end of 2023 rather than at the end of 2022, as assumed in the 2022 IRP Update, as incorporated into the 2022 RPS Development Plan. The revised assumption appropriately affects the dispatch of the units in 2023 but does not affect the plan for the development of solar, onshore wind, and energy storage (which is constrained by project development times). The Company uses PLEXOS to model the dispatch of the fleet in the PJM energy market. The dispatch of the fleet produces the system's CO_2 emissions. The PLEXOS dispatch logic includes RGGI compliance costs in the same manner that it includes fuel costs. Therefore, a Company-owned fossil unit operates when the compliance cost of RGGI plus other variable costs like fuel are less than the cost of a market power purchase. In following the RPS Development Plan and including RGGI costs in dispatch decisions, the Company's RGGI compliance cost modeling corresponds to its RPS plan filings.

Attachment 73

part 1

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

20201209012

Case Number (if already assigned)	PUR-2020-00169
Case Name (if known)	Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia
Document Type	EXPE
Document Description Summary	Petition of Virginia Electric and Power Company and Request for Limited Waivers
Total Number of Pages	100
Submission ID	20299
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November 9, 2020

BY ELECTRONIC DELIVERY

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State Corporation Commission
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Richmond, Virginia 23219

Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia
Case No. PUR-2020-00169

Dear Mr. Logan:

Please find enclosed for electronic filing in the above-captioned proceeding the *Petition of Virginia Electric and Power Company and Request for Limited Waivers.*

Please do not hesitate to call if you have any questions in regard to the enclosed.

Highest regards,

/s/ Elaine S. Ryan

Elaine S. Ryan

Enclosures

cc: William H. Chambliss, Esq.
Arlen Bolstad, Esq.
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20201209152

Dominion Energy®

Petition of Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia

Volume 1 of 1

Case No. PUR-2020-00169

Filed: November 9, 2020

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Petition of Virginia Electric and Power Company
For approval of a rate adjustment clause, designated Rider RGGI,
under § 56-585.1 A 5 e of the Code of Virginia
Case No. PUR-2020-00169

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY	)	
	)	Case No. PUR-2020-00169
For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia	)	

PETITION OF VIRGINIA ELECTRIC AND POWER COMPANY
AND REQUEST FOR LIMITED WAIVERS

Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), by counsel, hereby files with the State Corporation Commission of Virginia ("Commission") its petition for approval of a rate adjustment clause ("RAC"), designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia ("Va. Code") to recover projected and actual costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide ("CO_2") emissions, a program in which the Company is required to participate. The Company further requests limited waivers of certain Rules Governing Utility Rate Applications and Annual Informational Filings (the "Rate Case Rules"). In support of its petitions and request for limited waivers (collectively, the "Petition"), the Company respectfully shows as follows:

GENERAL INFORMATION

1. Dominion Energy Virginia is a public service corporation organized under the laws of the Commonwealth of Virginia furnishing electric service to the public within its certificated service territory. The Company also supplies electric service to non-jurisdictional customers in Virginia and to the public in portions of North Carolina. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to

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the public for compensation. The Company is also a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. The Company is an operating subsidiary of Dominion Energy, Inc.

2. The Company's address is:

Virginia Electric and Power Company
120 Tredegar Street
Richmond, Virginia 23219

3. The names, addresses, and telephone numbers of the attorneys for the Company are:

Paul E. Pfeffer
David J. DePippo
Dominion Energy Services, Inc.
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BACKGROUND

4. Initiated in 2009, RGGI is the first mandatory market-based program in the United States to reduce greenhouse gas emissions. RGGI is a collaborative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York,

Rhode Island, Vermont, and New Jersey to cap and reduce CO_2 emissions from the power sector. CO_2 allowances are obtained by RGGI participants through quarterly, regional auctions.

5. In May 2019, the Virginia Department of Environmental Quality ("DEQ") issued a final rule establishing a state carbon regulation program linked to RGGI (the "DEQ Carbon Rule" or "Rule"). Although the DEQ Carbon Rule was finalized in 2019, language in the state budget bill prohibited DEQ from continued work on the Rule. During the 2020 Regular Session, the General Assembly passed the Clean Energy and Community Flood and Preparedness Act, Senate Bill No. 1027 and House Bill No. 981, which authorized Virginia to become a full participant of RGGI and authorized DEQ to implement the DEQ Carbon Rule. The legislation became effective July 1, 2020. With the passage of this legislation, DEQ revised the DEQ Carbon Rule to clarify that the Commonwealth will join RGGI in 2021. The revised Rule was signed by the DEQ on June 25, 2020, and became effective on July 10, 2020. DEQ held a meeting to inform stakeholders about the Rule revisions, including any near-term compliance submittals required of companies subject to the Rule, on August 12, 2020.

6. The DEQ Carbon Rule will cap CO_2 emissions for Virginia at 27.1 million short tons for calendar year 2021, and decrease the emissions cap annually by approximately 3% to achieve a 30% reduction from 2020 levels to a level of 19.6 million short tons in 2030. Emission sources subject to the Rule will be required to obtain and surrender a CO_2 emission allowance for every short ton of CO_2 emitted during a control period through participation in the RGGI allowance auction program.

7. The Company owns regulated emissions sources, so must comply with RGGI.

8. Va. Code § 56-585.1 A 5 e permits cost recovery related to compliance with RGGI and establishes the applicable standard of review:

> A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of . . . [p]rojected and actual costs of projects that the Commission finds to be necessary . . . to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the costs of allowances purchased through a market-based trading program for carbon dioxide emissions. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations.

RIDER RGGI

9. The Company estimates it will initially require approximately 19,000,000 CO_2 allowances per year to cover CO_2 emissions from its Virginia-based generation fleet. Accordingly, by July 31, 2022, the Company expects to need approximately 29,000,000 CO_2 allowances.

10. Generally, to meet its obligations under RGGI, the Company intends to follow a programmatic approach by purchasing most of the required allowances in the RGGI quarterly auctions and using the secondary market to fill any auction deficiencies. More specifically, Dominion Energy Virginia plans to acquire approximately 25% of the forecasted annual allowance requirement in each of the quarterly auctions. If the Company fails to secure approximately 25% in an auction, the Company will look to purchase allowances in the secondary market. Also, Dominion Energy Virginia will seek to maintain a bank of allowances equal to approximately 10% to 20% of the annual requirement. The purpose of the bank is to protect customers from short-term allowance price volatility. The Company's compliance strategy is not based on any price outlook. Instead, the Company intends to follow a programmatic, auction-based approach to compliance. The Company may adjust its compliance strategy as needed to adapt to changes in the structure of the RGGI program.

11. The Company has assumed a weighted average price of $6.84 per allowance. This assumption is based on the actual clearing pricing in RGGI Auction 49 and actual transactions in the secondary market, combined with the ICF forward price curve.

12. The Company's RAC revenue requirement in this proceeding includes the Projected Cost Recovery Factor. Beginning with the next RAC filing expected to be made in 2021, the revenue requirement will also include the Actual Cost True-Up Factor. The Projected Cost Recovery Factor calculation results in the operating income necessary for recovery of amortization expense for CO_2 allowances as well as projected financing costs on the unamortized purchased CO_2 allowance balances. In addition, the Projected Cost Recovery Factor includes the amortization of deferred costs, including financing costs, incurred prior to this initial Rate Year. No Actual Cost True-Up Factor is included in this initial proceeding because this filing represents the initial request for cost recovery. It is anticipated that any true-up for calendar year 2020 will be included in a 2021 update filing for implementation during an August 1, 2022 to July 31, 2023 rate year. At that time, and for years beyond, the Actual Cost True-Up Factor will recover from, or credit to, customers any under- or over-recovery of costs from the most recently completed calendar year. Actual revenues recovered during the test year are compared to actual costs incurred during the test year. Any difference in these amounts becomes the Actual Cost True-Up Factor credited to, or recovered from, customers through the total revenue requirement requested for recovery during the rate year.

13. The total revenue requirement requested for recovery in this initial Rider RGGI Petition for the Rate Year beginning August 1, 2021, is $168,260,000.

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14. The Company proposes to use an energy allocation factor to allocate costs to the Virginia jurisdiction and that the costs be recovered through a uniform charge per kilowatt-hour ("kWh") from all bundled service customers in the Virginia jurisdiction.

15. The implementation of the proposed Rider RGGI on August 1, 2021, will increase the residential customer's monthly bill, based on 1,000 kWh per month, by $2.39.

SUPPORTING TESTIMONY, FILING SCHEDULE 46, AND REQUEST FOR LIMITED WAIVERS OF RATE CASE RULES FILING REQUIREMENTS

16. The Company's Petition is supported by the pre-filed direct testimonies of Company Witnesses C. Eric McMillan, Shane T. Compton, John C. Ingram, and Paul B. Haynes.

17. Section Rule 60 of the Rate Case Rules provides that an application filed pursuant to Subsection A 5 "shall include Schedules 45 and 46 as identified and described in 20 VAC 5-201-90, and which shall be submitted with the utility's direct testimony." The Company is filing with this Petition, Filing Schedule 46, as follows:

a. Company Witnesses McMillan and Compton co-sponsor Schedule 46A, consisting of Statements 1 and 2. Schedule 46A, Statement 1, provides projected costs associated with Rider RGGI, while Schedule 46A, Statement 2, provides documentation supporting the projected costs.

b. Company Witness Ingram sponsors Schedule 46B, consisting of Statements 1 and 2. These statements provide revenue requirement information for the proposed RAC and describe all significant accounting procedures and internal controls to identify costs related to RGGI allowances.

c. Company Witness Haynes sponsors Schedule 46C, consisting of Statement 1, which provides details of the Company's methodology for allocating the Rider RGGI revenue requirement.

18. The Company, for good cause shown and pursuant to 20 VAC 5-201-10 E of the Rate Case Rules, respectfully requests that the Commission waive, in part, the requirements under Rules 60 and 90 of the Rate Case Rules with respect to Filing Schedule 45 (Return on Equity Peer Group Benchmark). Pursuant to the provisions of Va. Code §§ 56-585.1 and 56-

585.1:1, and consistent with recent Commission orders granting similar limited waivers,[1] a return on equity determination is not to be made in this proceeding. Therefore, good cause exists, as required by Rule 10 E, for the Commission to waive in part the requirements of Rules 60 and 90 of the Rate Case Rules with respect to Filing Schedule 45.

19. The Company, for good cause shown and pursuant to 20 VAC 5-201-10 E, additionally respectfully requests that the Commission waive, in part, the requirement under Rules 60 and 90 of the Rate Case Rules to "[p]rovide the annual revenue requirement over the duration of the proposed rate adjustment clause by year and by class." Specifically, the Company requests waiver of two portions of this requirement. First, the Company seeks waiver of this requirement related to information for the "duration of the proposed rate adjustment clause." By statute, RGGI will continue indefinitely; Rider RGGI thus differs from other Company RACs approved by the Commission for assets that have a specific lifetime. Second, the Company seeks waiver of this requirement related to providing information on the revenue requirement "by class." As explained by Company Witness Haynes, the Company has developed a uniform charge per kilowatt-hour applicable to all bundled service customers in the Virginia jurisdiction. Accordingly, the revenue requirement is not available "by class." For these reasons, good cause exists, as required by Rule 10 E, for the Commission to waive in part the requirements of Rules 60 and 90 of the Rate Case Rules with respect to this limited portion of Schedule 46.

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[1] *See, e.g., Petition of Virginia Electric and Power Company, For approval and certification of the proposed US-4 Solar Project pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, and for approval of a rate adjustment clause, designated Rider US-4, under § 56-585.1 A 6 of the Code of Virginia,* Case No. PUR-2019-00105, Order for Notice and Hearing at 21, Ordering Paragraph (21) (Jul. 31, 2019).

COMPLIANCE WITH RULE 10 OF THE RATE CASE RULES

20. The Company's Petition for approval of Rider RGGI complies with the requirements contained in Rule 10 of the Rate Case Rules. In accordance with Rule 10 A, the Company filed with the Commission on September 8, 2020, the Company's notice of intent to file this Petition under Va. Code § 56-585.1 A 5.[2] Copies of the public version of this Petition, to the extent required by Rule 10 J, along with the additional information required by Rule 10 J, have been served upon the persons addressed in that Rule. A complete copy of the public version of this Petition has been served upon the Office of the Attorney General's Division of Consumer Counsel in conformity with Rule 10 J. Also included with and following this Petition, pursuant to Rule 10, is a table of contents of this filing, including testimony and schedules.

21. Beyond the initial Petition, Rate Case Rule 10 J requires the Company to serve copies of certain information related to Dominion Energy Virginia's rate proceedings upon local officials via first class mail or personal delivery. The Company has obtained a continuing waiver of Rule 10 J from the Commission to permit electronic delivery of rate application information to the localities in lieu of first class mail delivery upon request from the locality.[3] Accordingly, the Company requests that any procedural order issued in this proceeding allow for electronic service of materials going forward on localities that request such service in writing.

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[2] This notice dated September 8, 2020, indicated the Company's intent to file this Petition on or after October 5, 2020. On that same day, the Company filed a motion for limited waiver of the 60-day notice requirement of Rule 10 A. On September 23, 2020, the Commission denied the motion. Based on that order, on September 25, 2020, the Company filed an amended notice of intent to file this Petition under Va. Code § 56-585.1 A 5 on or after November 9, 2020.

[3] *Petition of Virginia Electric and Power Company, For a continuing waiver of 20 VAC 5-201-10 J of the Rules Governing Utility Rate Applications and Annual Informational Filings to permit electronic service to local officials upon request*, Case No. PUE-2016-00039, Final Order at 2-3 (Apr. 19, 2016).

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CONCLUSION

WHEREFORE, Dominion Energy Virginia respectfully requests that the Commission (i) approve the proposed revenue requirement for service rendered on and after August 1, 2021, to recover projected and actual costs related to the purchase of CO_2 allowances to comply with RGGI; (ii) approve the Company's proposed Rider RGGI, effective for usage on and after August 1, 2021; (iii) grant the Company's requested limited waivers outlined in the Petition; and (iv) grant such other relief as deemed appropriate and necessary.

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

By: */s/ Elaine S. Ryan*
Counsel

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Counsel for Virginia Electric and Power Company

November 9, 2020

20211208012

WITNESS DIRECT TESTIMONY SUMMARY

Witness: C. Eric McMillan

Title: Manager, Power Contracts and Origination

Summary:

Company Witness C. Eric McMillan provides a general overview of the Regional Greenhouse Gas Initiative ("RGGI") and describes the mechanics of the RGGI auctions. Mr. McMillan also explains how the Company plans to meet its obligations under RGGI, and will describe the Company's participation in these markets to date.

Mr. McMillan explains that RGGI is the first mandatory market-based program in the United States to reduce greenhouse gas emissions. CO_2 allowances are obtained by RGGI participants through quarterly, regional auctions or through secondary markets. In 2020, the Virginia General Assembly passed the Clean Energy and Community Flood and Preparedness Act, which authorized Virginia to become a full participant of RGGI and authorized the Virginia Department of Environmental Quality ("DEQ") to implement its DEQ Carbon Rule. The DEQ Carbon Rule caps CO_2 emissions for Virginia at 27.1 million short tons for calendar year 2021, and decreases the emissions cap annually by approximately 3% to achieve a 30% reduction from 2020 levels to a level of 19.6 million short tons in 2030. The Company owns regulated emissions sources, so must comply with RGGI.

Regulated emissions sources must acquire CO_2 allowances equal to their CO_2 emissions over each three-year RGGI control period. Each allowance represents a limited authorization to emit one short ton of CO_2 from a regulated source. RGGI has had four three-year control periods since it began in 2009. The fifth control period starts on January 1, 2021 and ends December 31, 2023. In addition to the three-year control period requirements, RGGI has interim control periods that require regulated sources to hold a minimum of 50% of their allowances by the end of each of the first two calendar years of the control period. Regulated sources demonstrate compliance by holding sufficient allowances in each source compliance account.

To meet its obligations under RGGI, the Company intends to follow a programmatic approach by purchasing most of the required allowances in the quarterly auctions and using the secondary market to fill any auction deficiencies. More specifically, Dominion Energy Virginia plans to acquire approximately 25% of the forecasted annual allowance requirement in each of the quarterly auctions. If the Company fails to secure approximately 25% in an auction, the Company will look to purchase allowances in the secondary market. Also, Dominion Energy Virginia will seek to maintain a bank of allowances equal to approximately 10% to 20% of the annual requirement. The purpose of the bank is to protect customers from short-term allowance price volatility.

Mr. McMillan supports the weighted average price assumption of $6.84 per CO_2 allowance. This assumption is based on the actual clearing pricing in RGGI Auction 49 and actual transactions in the secondary market, combined with the ICF forward price curve.

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DIRECT TESTIMONY
OF
C. ERIC MCMILLAN
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2020-00169

Q. Please state your name, business address, and position with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company").

A. My name is C. Eric McMillan, and I am a Manager of Power Contracts and Origination for the Company. My business address is 600 East Canal Street, Richmond, Virginia 23219. A statement of my background and qualifications is attached as Appendix A.

Q. Please describe your areas of responsibility with the Company.

A. In my current position, I lead a team that is responsible for managing the Company's compliance with the Regional Greenhouse Gas Initiative ("RGGI") and the mandatory renewable energy portfolio standard program from a market procurement perspective. I also am responsible for the negotiation, origination, and day-to-day administration of the Company's non-utility generation power contracts.

Q. What is the purpose of your testimony in this proceeding?

A. I am testifying in support of the Company's petition for approval of a rate adjustment clause ("RAC"), designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia ("Va. Code") to recover projected and actual costs related to the purchase of allowances through the RGGI market-based trading program for carbon dioxide ("CO_2") emissions, a program in which the Company is required to participate. I will provide a general overview of RGGI and describe the mechanics of the RGGI auctions. I will also explain

20211202-0112

how the Company plans to meet its obligations under RGGI, and will describe the Company's participation in these markets to date.

Q. Are you sponsoring an exhibit in this proceeding?

A. Yes. Although there are no schedules attached to my testimony, I am co-sponsoring Filing Schedule 46A, Statements 1 and 2, with Company Witness Shane T. Compton, which provide information required by Rules 60 and 90 of the Commission's Rules Governing Utility Rate Applications and Annual Informational Filings. Schedule 46A, Statement 1, provides projected costs associated with Rider RGGI, while Schedule 46A, Statement 2, provides documentation supporting the projected costs. These statements were prepared under my direction and supervision and are accurate and complete to the best of my knowledge and belief.

Q. What is RGGI?

A. Initiated in 2009, RGGI is the first mandatory market-based program in the United States to reduce greenhouse gas emissions. RGGI is a collaborative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, Vermont, and New Jersey to cap and reduce CO_2 emissions from the power sector. CO_2 allowances are obtained by RGGI participants through quarterly, regional auctions. In most RGGI states, auction revenue is returned to state coffers. In addition to Virginia joining RGGI in 2021, Pennsylvania is expected to join RGGI in 2022.

Q. Please provide an overview of the Commonwealth's participation in RGGI.

A. In May 2019, the Virginia Department of Environmental Quality ("DEQ") issued a final rule establishing a state carbon regulation program linked to RGGI (the "DEQ Carbon Rule" or "Rule"). Although the DEQ Carbon Rule was finalized in 2019, language in the state budget bill prohibited the DEQ from continued work on the Rule. During the 2020 Regular Session, the General Assembly passed the Clean Energy and Community Flood and Preparedness Act, Senate Bill No. 1027 and House Bill No. 981, which authorized Virginia to become a full participant of RGGI and authorized the DEQ to implement the DEQ Carbon Rule. The legislation became effective July 1, 2020.

With the passage of this legislation, the DEQ revised the DEQ Carbon Rule to clarify that the Commonwealth will join RGGI in 2021. The revised Rule was signed by the DEQ on June 25, 2020, and became effective on July 10, 2020. The DEQ held a meeting to inform stakeholders about the Rule revisions, including any near-term compliance submittals required of companies subject to the Rule, on August 12, 2020.

Q. What does the DEQ Carbon Rule require in terms of reduced emissions?

A. The DEQ Carbon Rule will cap CO_2 emissions for Virginia at 27.1 million short tons for calendar year 2021, and decrease the emissions cap annually by approximately 3% to achieve a 30% reduction from 2020 levels to a level of 19.6 million short tons in 2030. Emission sources subject to the Rule will be required to obtain and surrender a CO_2 emission allowance for every short ton of CO_2 emitted during a control period through participation in the RGGI allowance auction program.

Q. Is the Company required to comply with the DEQ Carbon Rule?

A. Yes. The Company owns regulated emissions sources, so must comply with RGGI.

Q. How is compliance demonstrated under RGGI?

A. Regulated emissions sources must acquire CO_2 allowances equal to their CO_2 emissions over each three-year RGGI control period. Each allowance represents a limited authorization to emit one short ton of CO_2 from a regulated source. These regulated sources can use CO_2 allowances issued by any participating RGGI state during the current year, or any future year.

RGGI has had four three-year control periods since it began in 2009. The fifth control period starts on January 1, 2021 and ends December 31, 2023. In addition to the three-year control period requirements, RGGI has interim control periods that require regulated sources to hold a minimum of 50% of their allowances by the end of each of the first two calendar years of the control period. Regulated sources demonstrate compliance by holding sufficient allowances in each source compliance account.

Q. How do regulated sources acquire CO_2 allowances?

A. Regulated sources acquire CO_2 allowances by purchasing them at quarterly auctions or through secondary markets. CO_2 allowances purchased by the winning bidders in the quarterly auctions and CO_2 allowances traded in the secondary market are tracked and recorded in the RGGI CO_2 Allowance Tracking System ("COATS"). RGGI allowances currently do not have any limitations on banking. Potomac Economics serves as the independent market monitor for RGGI. The market monitor covers both the auctions and

the secondary market, and publishes quarterly reports analyzing each RGGI auction and activity in the CO_2 allowance secondary market.

Q. Please explain how the RGGI quarterly auctions work.

A. The RGGI member states use an online platform to offer and sell CO_2 allowances in quarterly auctions. The RGGI member states are the only market participants permitted to offer allowances in these auctions. The auctions are conducted in accordance with the statutory and/or regulatory authority of each state offering CO_2 allowances for sale in the auctions.

The quarterly auctions are open to any interested bidder that meets the financial qualifications. Auction bidders must provide sufficient collateral to fully cover all their bidding activity. The auction clearing prices are determined by ordering the bids by dollar value highest to lowest, and then allocating allowances to the bids in descending dollar value until all the allowances have been allocated. The marginal bid—or the lowest bid to receive allowances—then becomes the auction clearing price. All winning bidders pay the auction clearing price for every CO_2 allowance allocated to them.

Q. Please describe the secondary market for RGGI CO_2 allowances.

A. The secondary market allows market participants to buy and sell physical allowances outside of the quarterly auctions, facilitates price discovery in between quarterly auctions, and provides tools to manage price risk and volatility. The secondary market includes the trading of physical allowances and financial products.

A physical CO_2 allowance trade occurs when a buyer and seller agree to specific commercial terms such as price, volume, and vintage, and then register the transfer of allowance ownership in RGGI COATS.

Financial products include any contracts whereby the buyer and seller agree to exchange funds and/or allowances at some future date under specific conditions. Many financial products are designed to, and eventually result in, the transfer of physical CO_2 allowances in RGGI COATS. Depending on the product and the agreed-to commercial terms, this transfer may occur months or even years after the financial transaction was executed by the buyer and seller. The most commonly traded financial products are forward contracts and futures contracts. In forward contracts, which typically are traded in the over the counter ("OTC") market, parties agree to exchange allowances at a set price and quantity at some future date. Forwards are non-standard contracts transacted outside of an exchange. Futures contracts are standardized, exchange-traded contracts. One futures contract equals 1,000 CO_2 allowances. All allowances, regardless of product, must be transferred from seller to buyer in the COATS registry.

Q. Please describe the historical pricing and volumes that have cleared in the RGGI auctions since 2015.

A. Figure 1 shows the RGGI quarterly auction volume that has cleared through September 2020, as well as projections of auction volume in the next two auctions. Note that the March 2021 auction shows the introduction of Virginia volumes into the quarterly auction for the first time.

Figure 1: RGGI Quarterly Auction Volume (Mar. 2015 to Mar. 2021)

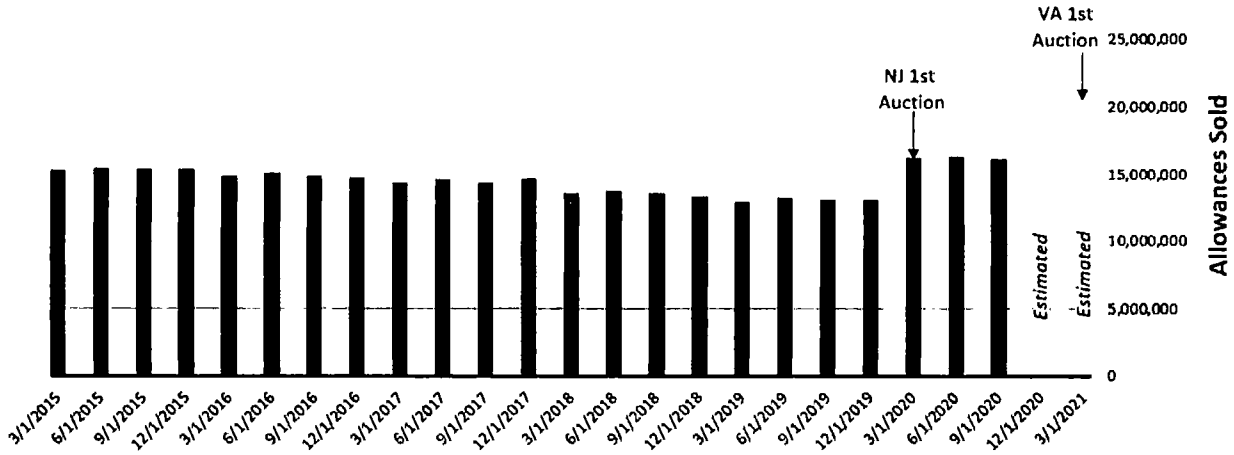
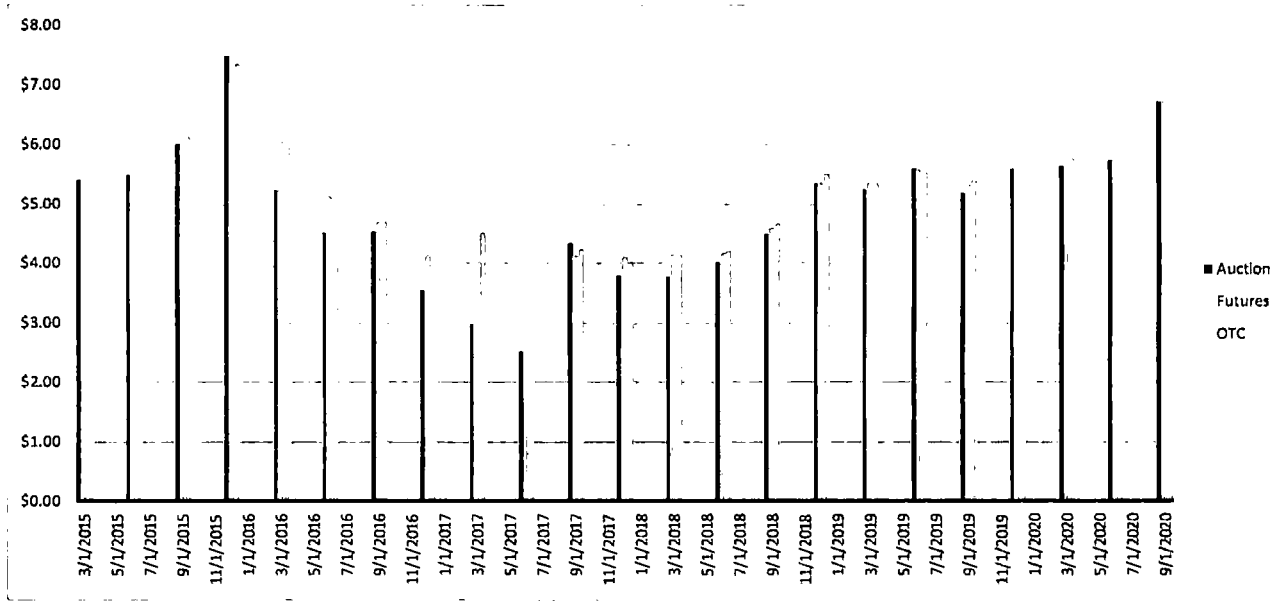


Figure 2 shows the historical prices of RGGI allowances that have cleared through the quarterly auctions as well as the secondary markets. Allowance prices have ranged from $2.53/short ton to $7.50/short ton in the RGGI auctions during this timeframe.

Figure 2: RGGI Quarterly Auction Clearing Price (Mar. 2015 to Sept. 2020)



Q. How many CO_2 allowances does the Company expect to need once Virginia joins RGGI?

A. As supported by Company Witness Compton, the Company estimates it will initially require approximately 19,000,000 CO_2 allowances per year to cover CO_2 emissions from its generation fleet in Virginia during the fifth control period. Based on the projected CO_2 emissions requirements, the Company would need to hold at least 9,500,000 allowances by December 31, 2021, and at least 19,000,000 allowances by December 31, 2022.

Q. Generally, how does the Company plan to meet its obligations under RGGI?

A. In general, the Company intends to follow a programmatic approach by purchasing most of the required allowances in the quarterly auctions and using the secondary market to fill any auction deficiencies. More specifically, Dominion Energy Virginia plans to acquire approximately 25% of the forecasted annual allowance requirement in each of the quarterly auctions. If the Company fails to secure approximately 25% in an auction, the Company will look to purchase allowances in the secondary market. Also, Dominion Energy Virginia will seek to maintain a bank of allowances equal to approximately 10% to 20% of the annual requirement. The purpose of the bank is to protect customers from short-term allowance price volatility.

The Company's compliance strategy is not based on any price outlook. Instead, the Company intends to follow a programmatic, auction-based approach to compliance. The Company may adjust its compliance strategy as needed to adapt to changes in the structure of the RGGI program.

Q. Has the Company started to procure CO_2 allowances to meet its obligations?

A. RGGI Auction 49 occurred in September 2020 with a clearing price of $6.82 per allowance. Dominion Energy Virginia started purchasing small volumes of CO_2 allowances in this auction, purchasing 750,000 allowances. In the secondary market, the Company purchased 250,000 vintage 2020 allowances at $6.73 for September 2020 delivery. While the Company intends to bid on additional allowances in RGGI Auction 50 scheduled for December 2020 and may purchase allowances in the secondary market, the Company does not intend to purchase significant volumes of allowances until the Commonwealth begins selling allowances in the March 2021 auction.

Q. What price for CO_2 allowances has the Company used to calculate the revenue requirement in this proceeding?

A. The Company has assumed a weighted average price of $6.84 per allowance. This assumption is based on the actual clearing pricing in RGGI Auction 49 and actual transactions in the secondary market, combined with the ICF forward price curve as supported by Company Witness Compton. As discussed further by Company Witness John C. Ingram, the revenue requirement will be trued up in future Rider RGGI proceedings based on actual prices paid for CO_2 allowances.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

20141202

BACKGROUND AND QUALIFICATIONS
OF
C. ERIC MCMILLAN

C. Eric McMillan joined the Company in 2008 as an Associate Financial Analyst in the Generation Financial Services Department. Since then he has held various financial, business development, and renewable operations roles within the power generation business segment of the Company. In 2015, Mr. McMillan was promoted to Manager of Renewable Energy Operations. In October 2019, he assumed his current position of Manager of Power Contracts and Origination. In his current role, Mr. McMillan is responsible for the negotiation, origination, and day-to-day administration of the Company's NUG power contracts.

Mr. McMillan graduated from the Longwood University in 2006 with a Bachelor of Science degree in Business Administration with concentrations in Finance. In 2013, Mr. McMillan obtained a Masters of Science in Finance degree from Virginia Commonwealth University.

20112012

WITNESS DIRECT TESTIMONY SUMMARY

Witness: Shane T. Compton

Title: Manager, Integrated Strategic Planning

Summary:

Company Witness Shane T. Compton provides the forecast of CO_2 emissions from the Company's generation facilities used to determine the projected volume of CO_2 allowances needed to meet the Company's obligations under RGGI. Mr. Compton states that the Company used PLEXOS modeling software to simulate the economic dispatch of the Company's generating units to meet projected load requirements. The projected CO_2 emission production was then pulled for each Company-owned CO_2-emitting resource located in Virginia. Mr. Compton estimates that the Company will initially require approximately 19,000,000 CO_2 allowances per year to cover CO_2 emissions from its Virginia-based generation fleet. Accordingly, by July 31, 2022, the Company expects to need approximately 29,000,000 CO_2 allowances.

2020-0169

DIRECT TESTIMONY
OF
SHANE T. COMPTON
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2020-00169

Q. Please state your name, business address, and position with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company").

A. My name is Shane T. Compton and I am Manager of Integrated Strategic Planning. My business address is 600 East Canal Street, Richmond, Virginia 23219. A statement of my background and qualifications is attached as Appendix A.

Q. Mr. Compton, what is the purpose of your testimony in this proceeding?

A. I am testifying in support of the Company's petition for approval of a rate adjustment clause ("RAC"), designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia ("Va. Code") to recover projected and actual costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide ("CO_2") emissions. I will support the forecast of CO_2 emissions from the Company's generation facilities.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, STC, consisting of Schedule 1, was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief. I am also co-sponsoring Filing Schedule 46A, Statements 1 and 2, with Company Witness C. Eric McMillan, which provide information required by Rules 60 and 90 of the Commission's Rules Governing Utility Rate Applications and Annual Informational

Filings. Schedule 46A, Statement 1, provides projected costs associated with Rider RGGI, while Schedule 46A, Statement 2, provides documentation supporting the projected costs.

Q. How did the Company determine the projected volume of CO_2 allowances needed to meet its obligation under RGGI?

A. PLEXOS modeling software was used to simulate the economic dispatch of the Company's generating units to meet projected load requirements. The projected CO_2 emission production was then pulled for each Company-owned CO_2-emitting resource located in Virginia. The Company did not include CO_2 emissions from its units in West Virginia (*i.e.*, Mt. Storm) or North Carolina (*i.e.*, Rosemary). As explained by Company Witness C. Eric McMillan, the Company must obtain and surrender a CO_2 allowance for every short ton of CO_2 emitted from regulated sources.

Q. What is the projected volume of CO_2 allowances that the Company expects to require through the end of the rate year in this proceeding—July 31, 2022?

A. The Company estimates it will initially require approximately 19,000,000 CO_2 allowances per year to cover CO_2 emissions from its Virginia-based generation fleet. Accordingly, by July 31, 2022, the Company expects to need approximately 29,000,000 CO_2 allowances. My Schedule 1 shows the projected CO_2 emissions by month for 2021 and 2022.

Q. Will Virginia joining RGGI affect the dispatch of the Company's generation units?

A. Yes, it will. Regulated sources (*i.e.*, the Company's carbon-emitting generating units that are subject to RGGI) must purchase a CO_2 allowance for every CO_2 short ton emitted

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during a specific compliance period. All else equal, adding the cost of CO_2 allowances to carbon-emitting generating units that are subject to RGGI will likely result in those units dispatching less. In modeling space, PLEXOS takes this into account by adding a forecasted cost of CO_2 allowances to its generating units in Virginia subject to RGGI. My Schedule 1 shows the projected CO_2 allowance prices used in PLEXOS. As the carbon-emitting generating units dispatch less, PLEXOS replaces the lost generation with market purchases.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

20112012

BACKGROUND AND QUALIFICATIONS
OF
SHANE T. COMPTON

Shane Compton joined the Company in 2007 as an Hourly Trader in the Energy Marketing group. Since then he has held various financial and planning roles within the power generation and corporate strategic planning segments of the Company. In 2015, Mr. Compton was promoted to Manager of Financial & Business Services. In September 2019, he assumed his current position of Manager of Generation System Planning. In his current role, Mr. Compton is responsible for developing generation portfolio plans to serve the Company's long-term customer capacity and energy needs.

Mr. Compton graduated from Virginia Tech in 2004 with a Bachelor of Science degree in Business Administration with a concentration in Finance. In 2014, Mr. Compton obtained a Master of Business Administration degree from Virginia Commonwealth University.

20211209-12

CO_2 Volume and Price Forecast

(Tons CO_2 and Allowance Prices from Oct. 2020 PLEXOS Outlook)

	Tons CO_2	Allowance Price
Jan-21	1,337,487	$6.91
Feb-21	1,388,272	$6.91
Mar-21	1,447,889	$6.91
Apr-21	1,148,777	$6.91
May-21	1,415,430	$6.91
Jun-21	1,632,852	$6.91
Jul-21	2,093,198	$6.91
Aug-21	2,151,129	$6.91
Sep-21	1,519,562	$6.91
Oct-21	873,141	$6.91
Nov-21	1,235,813	$6.91
Dec-21	1,618,607	$6.91
Jan-22	1,625,533	$6.69
Feb-22	1,674,251	$6.69
Mar-22	1,651,361	$6.69
Apr-22	1,440,970	$6.69
May-22	1,253,849	$6.69
Jun-22	1,650,957	$6.69
Jul-22	2,288,023	$6.69
Aug-22	2,317,061	$6.69
Sep-22	1,699,243	$6.69
Oct-22	942,157	$6.69
Nov-22	1,669,331	$6.69
Dec-22	1,858,761	$6.69

20212081-2

WITNESS DIRECT TESTIMONY SUMMARY

Witness: John C. Ingram

Title: Director, Regulatory Accounting

Summary:

Company Witness John C. Ingram provides the calculation of the revenue requirement associated with Rider RGGI for the rate year of August 1, 2021 through July 31, 2022 ("Rate Year"). The Company is requesting a total revenue requirement of $168,260,000 for the Rate Year.

Mr. Ingram explains that the Company's RAC revenue requirement in this proceeding includes the Projected Cost Recovery Factor. Beginning with the next RAC filing expected to be made in 2021, the revenue requirement will also include the Actual Cost True-Up Factor. The Projected Cost Recovery Factor calculation results in the operating income necessary for recovery of amortization expense for CO_2 allowances as well as projected financing costs on the unamortized purchased CO_2 allowance balances. In addition, the Projected Cost Recovery Factor includes the amortization of deferred costs, including financing costs, incurred prior to this initial Rate Year. No Actual Cost True-Up Factor is included in this initial proceeding because this filing represents the initial request for cost recovery. It is anticipated that any true-up for calendar year 2020 will be included in a 2021 update filing for implementation during an August 1, 2022 to July 31, 2023 rate year. At that time, and for years beyond, the Actual Cost True-Up Factor will recover from, or credit to, customers any under- or over-recovery of costs from the most recently completed calendar year. Actual revenues recovered during the test year are compared to actual costs incurred during the test year. Any difference in these amounts becomes the Actual Cost True-Up Factor credited to, or recovered from, customers through the total revenue requirement requested for recovery during the rate year.

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DIRECT TESTIMONY
OF
JOHN C. INGRAM
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2020-00169

Q. Please state your name, business address, and position with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company").

A. My name is John C. Ingram, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am a Director – Regulatory Accounting and am responsible primarily for overseeing regulatory accounting matters and the analysis and development of revenue requirement calculations for the Company. A statement of my background and qualifications is attached as Appendix A.

Q. What is the purpose of your testimony in this proceeding?

A. I am testifying in support of the Company's petition for approval of a rate adjustment clause ("RAC"), designated Rider RGGI, under § 56-585.1 A 5 e ("Subsection A 5 e" or "A 5") of the Code of Virginia ("Va. Code") to recover projected and actual costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide ("CO_2") emissions. I will address the development of the revenue requirement associated with Rider RGGI for the rate year of August 1, 2021 through July 31, 2022 ("Rate Year").

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, JCI, consisting of Schedule 1, was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and

belief. Also, I am sponsoring Filing Schedule 46B, Statements 1 and 2, which provide information required by the Commission's Rules Governing Utility Rate Applications and Annual Informational Filings. These statements provide revenue requirement information for the proposed RAC and describe all significant accounting procedures and internal controls to identify costs related to RGGI allowances.

Q. Before discussing the revenue requirement, will you give a brief overview of the accounting treatment for RGGI allowances?

A. Purchased CO_2 allowances will be tracked in the aggregate as an intangible asset. As CO_2 emissions are produced each month, this intangible asset will be amortized based on the then-present weighted-average cost per allowance. Based on the timing of allowance auctions and purchase dates, the Company generally expects to carry an intangible asset representing aggregated purchased but unamortized RGGI CO_2 allowances.

Q. What rate of return on common equity ("ROE") is the Company utilizing in this proceeding?

A. The Company has used a ROE of 9.2% for purposes of calculating the Rider RGGI revenue requirement over the Rate Year in this case, consistent with the Final Order in Case No. PUR-2019-00050.

Q. What are the key components of the revenue requirement in this proceeding?

A. The Company's RAC revenue requirement in this proceeding includes the Projected Cost Recovery Factor. Beginning with the next RAC filing expected to be made in 2021, the revenue requirement will also include the Actual Cost True-Up Factor.

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The Projected Cost Recovery Factor calculation results in the operating income necessary for recovery of amortization expense for CO_2 allowances as well as projected financing costs on the unamortized purchased CO_2 allowance balances. In addition, the Projected Cost Recovery Factor includes the amortization of deferred costs, including financing costs, incurred prior to this initial Rate Year.

No Actual Cost True-Up Factor is included in this initial proceeding because this filing represents the initial request for cost recovery. It is anticipated that any true-up for calendar year 2020 will be included in a 2021 update filing for implementation during the August 1, 2022 to July 31, 2023 rate year. At that time, and for years beyond, the Actual Cost True-Up Factor will recover from, or credit to, customers any under or over recovery of costs from the most recently completed calendar year. Actual revenues recovered during the test year are compared to actual costs incurred during the test year. Any difference in these amounts becomes the Actual Cost True-Up Factor credited to, or recovered from, customers through the total revenue requirement requested for recovery during the Rate Year.

This request utilizes the end-of-test period capital structure and cost of capital pursuant to Va. Code § 56-585.1 A 10 and is consistent with the Order of the State Corporation Commission of Virginia ("Commission") on Commission Staff's Motion in Limine dated July 14, 2009 in Case No. PUE-2009-00019. For purposes of setting rates during the Rate Year, the end-of-test-period capital structure and cost of capital is the Company's December 31, 2019 year-end capital structure and year-end cost of capital ("Cost of Capital"). The calculation of the end-of-period capital structure and cost of capital excludes certain adjustments to the Company's common equity balance, in accordance

with the Commission's September 4, 2020 Final Order in Case No. PUR-2020-00003. The Company's Cost of Capital applied in this case is shown on page 12 of my Schedule 1.

Q. What deferred costs are being proposed for recovery in this filing?

A. The Company is deferring amortization expense for CO_2 allowances and financing costs on rate base calculated up to the beginning of the initial Rate Year and is proposing to recover them over the Rate Year in this current filing, consistent with past practice for deferred operating costs and rate base items in other Company RACs under Va. Code § 56-585.1 A 5 and A 6.

Q. Mr. Ingram, would you please discuss the Company's current proposal for calculating the Projected Cost Recovery Factor in this filing?

A. Yes. The revenue requirement to be recovered from Virginia Jurisdictional customers through the Projected Cost Recovery Factor is presented in my Schedule 1, page 1, and consists of the projected amortization expense for the CO_2 allowances during the Rate Year, the amortization of deferred costs over the Rate Year, and projected financing costs on purchased CO_2 allowances for the Rate Year (including income taxes on the equity component of the return). CO_2 allowance purchase volumes and prices and amortization volumes included in the revenue requirement calculation are supported by the direct testimony of Company Witnesses C. Eric McMillan and Shane T. Compton.

The financing cost portion of the revenue requirement is the result of multiplying thirteen-month average rate base as of July 31, 2022, by the Company's Cost of Capital. As noted above, the operating cost portion of the revenue requirement consists of

projected amortization expense for CO_2 allowances during the Rate Year and the amortization of deferred costs as previously described in my testimony.

Q. For purposes of this filing, please describe the composition of the rate base as presented in your Schedule 1.

A. Rate base is comprised of month-end unamortized purchased CO_2 allowance balances, cash working capital, and unrecovered deferred costs.

Q. Will any of the expenses requested for recovery in the instant case be requested for recovery in any of the Company's unrelated Virginia rate proceedings or filings such as its base rates, fuel, sales and use tax, or other unrelated rider cases?

A. No. Pursuant to Subsection A 5 e, the Company will only request recovery of those costs and expenses directly associated with the purchase and amortization of CO_2 allowances in Rider RGGI proceedings. Any indirect operating costs, such as broker fees or Dominion Energy Services, Inc. ("DES") costs, will be recovered in the Company's base rates. See Schedule 46B, Statement 2, for a more detailed description of the Company's accounting procedures and internal controls utilized to ensure the purchases and amortization of the CO_2 allowances are segregated for purposes of requesting recovery in the instant proceeding and, conversely, not requested for recovery in other non-related Company proceedings.

Q. What is the total revenue requirement in this filing?

A. As summarized on my Schedule 1, page 1, for the Rate Year beginning August 1, 2021, the Company is requesting recovery of a total revenue requirement of $168,260,000.

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Company Witness Paul B. Haynes's testimony addresses allocation of this revenue requirement among the customer classes.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF JOHN C. INGRAM, CPA

John C. Ingram graduated from the College of William and Mary in 1992 with a Bachelor of Business Administration degree (concentration in Accounting) and received his Certified Public Accountant license in 1994. He performed audit services for a national public accounting firm prior to joining Dominion Energy in 1999. Mr. Ingram has held various positions within Dominion Energy's accounting organization, including SEC reporting, accounting research, and Generation and Gas Infrastructure operating segment support. During his tenure in Generation accounting from 2005 through 2015, he was promoted to Manager in 2006 and Director in 2010. His responsibilities as Director primarily included overseeing personnel responsible for the Company's regulated generation accounting activities. From 2015 through May 2018, Mr. Ingram served as an accounting Director supporting Dominion Energy's Gas Infrastructure operating segment. In May 2018, Mr. Ingram assumed his current role as the Director of Regulatory Accounting where he is responsible for overseeing the analysis and development of revenue requirements for the Company's rate case proceedings.

Mr. Ingram has previously presented testimony and testified before the State Corporation Commission of Virginia.

2021200127

Virginia Electric and Power Company
Rider RGGI Revenue Requirement
For the Rate Year August 1, 2021 to July 31, 2022
(000s)

Line No.		
1	Projected Cost Recovery Factor	$ 168,260
2	Actual Cost True-Up Factor	-
3	Total Revenue Requirment	$ 168,260

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Virginia Electric and Power Company
Rider RGGI - Projected Cost Recovery Factor
For the Rate Year August 1, 2021 to July 31, 2022
(000s)

Line No.		Rider RGGI
1	Rate Base	$ 53,824
2	Weighted Average Cost of Capital	6.876%
3	Net Operating Income	3,701
	Less Interest Expense on Debt	
4	Weighted Average Cost Of Debt	2.056%
5	Weighted Average Debt Component Of JDC Expense	0.009%
6	Total Weighted Average Cost Of Debt	2.065%
7	Rate Base	53,824
8	Revenue Requirement - Interest Expense On Debt	1,111
9	Net Income	2,589
10	Income Tax Gross-up Factor	74.4%
11	Revenue Requirement - Net Income Including Income Taxes	3,481
12	**Revenue Requirement - Financing Costs**	4,593
13	**Revenue Requirement - Operating Expenses**	163,668
14	**Revenue Requirement Per Projected Cost Recovery Factor**	$ 168,260

Virginia Electric and Power Company
Rider RGGI Rate Base
For the Period September 2020 to December 2020
(000s)

Line No.		Aug-20	5ep-20	Oct-20	Nov-20	Dec-20
1	Allowances Inventory	$ -	$ 6,798	$ 6,798	$ 6,798	$ 13,708
2	Cash Working Capital	-	(43)	(43)	(43)	(43)
3	Subtotal	-	6,754	6,754	6,754	13,664
4	Factor 3 - Energy Factor	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%
5	Rate Base - Virginia Jurisdiction	-	5,427	5,427	5,427	10,979
6	Unamortized Deferred Costs	$ -	$ -	$ -	$ -	$ -
7	Rate Base - Virginia Jurisdiction	$ -	$ 5,427	$ 5,427	$ 5,427	$ 10,979

Company Exhibit No. __
Witness: JCI
Schedule 1
Page 3 of 12

20112200012

Virginia Electric and Power Company
Rider RGGI Rate Base
For the Period January 2021 to December 2021
(000s)

Line No.		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
1	Allowances Inventory	$ 4,541	$ (4,974)	$ 19,557	$ 11,608	$ 1,814	$ 25,080	$ 10,615	$ (4,250)	$ 19,800	$ 13,766	$ 5,227	$ 28,592
2	Cash Working Capital	(167)	(167)	(167)	(167)	(167)	(167)	19,262	19,262	19,262	19,262	19,262	19,262
3	Subtotal	4,373	(5,142)	19,390	11,441	1,647	24,913	29,877	15,012	39,062	$ 33,029	$ 24,489	$ 47,855
4	Factor 3 - Energy Factor	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%
5	Rate Base - Virginia Jurisdiction	3,514	(4,131)	15,580	9,193	1,323	20,017	24,006	12,062	31,386	$ 26,538	$ 19,677	$ 38,451
6	Unamortized Deferred Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 59,601	$ 54,634	$ 49,667	$ 44,701	$ 39,734	$ 34,767
7	Rate Base - Virginia Jurisdiction	$ 3,514	$ (4,131)	$ 15,580	$ 9,193	$ 1,323	$ 79,618	$ 78,641	$ 61,730	$ 76,087	$ 66,272	$ 54,444	$ 68,251

Company Exhibit No. ___
Witness: JCI
Schedule 1
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20112700012

Virginia Electric and Power Company
Rider RGGI Rate Base
For the Period January 2022 to July 2022
(000s)

Line No.		Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22
1	Allowances Inventory	$ 17,360	$ 5,791	$ 28,141	$ 18,456	$ 10,028	$ 32,421	$ 17,097
2	Cash Working Capital	20,607	20,607	20,607	20,607	20,607	20,607	20,607
3	Subtotal	$ 37,967	$ 26,398	$ 48,748	$ 39,063	$ 30,635	$ 53,028	$ 37,704
4	Factor 3 - Energy Factor	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%	80.3494%
5	Rate Base - Virginia Jurisdiction	$ 30,506	$ 21,211	$ 39,169	$ 31,387	$ 24,615	$ 42,608	$ 30,295
6	Unamortized Deferred Costs	$ 29,800	$ 24,834	$ 19,867	$ 14,900	$ 9,933	$ 4,967	$ -
7	Rate Base - Virginia Jurisdiction	$ 55,340	$ 41,078	$ 54,069	$ 41,320	$ 29,582	$ 42,608	$ 30,295

Company Exhibit No. ___
Witness: JCI
Schedule 1
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20141209012

Virginia Electric and Power Company
Rider RGGI Operating Expenses
For the Rate Year August 1, 2021 to July 31, 2022
(000s)

Line No.		Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	System Total	Allocation Factor	Virginia Jurisdiction Total
	Allowance Amortization	$ 14,865	$ 10,500	$ 6,033	$ 8,539	$ 11,185	$ 11,232	$ 11,569	$ 11,100	$ 9,686	$ 8,428	$ 11,057	$ 15,323	$ 129,518	80.3494%	$ 104,067
	Deferred Cost Amortization (VA Jurisdiction)	4,967	4,967	4,967	4,967	4,967	4,967	4,967	4,967	4,967	4,967	4,967	4,967	59,601		59,601
7	Total Rate Year Expense															$ 163,668

Company Exhibit No. ___
Witness: JCI
Schedule 1
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Virginia Electric and Power Company
Rider RGGI Pre-RAC Cost Deferral
For the Period September 2020 to July 31, 2021
($000s)

Line No.		Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21
1	Allowance Amortization	$ -	$ -	$ -	$ -	$ 9,167	$ 9,515	$ 10,019	$ 7,949	$ 9,794	$ 11,284	$ 14,465
4	Virginia Jurisdictional Allocation Factor	80.35%	80.35%	80.35%	80.35%	80.35%	80.35%	80.35%	80.35%	80.35%	80.35%	80.35%
5	Virginia Jurisdictional Total	-	-	-	-	7,365	7,645	8,050	6,387	7,870	9,066	11,623
6	Regulatory Asset Balance	-	-	-	-	7,365	15,011	23,061	29,448	37,317	46,384	58,006
7	Regulatory Asset Balance (Net of ADIT)	-	-	-	-	5,478	11,164	17,152	21,902	27,755	34,498	43,143
8	Average Regulatory Asset Balance (Net of ADIT)	-	-	-	-	2,739	8,321	14,158	19,527	24,829	31,127	38,821
9	Virginia Jurisdictional Rate Base	5,427	5,427	5,427	10,979	3,514	(4,131)	15,580	9,193	1,323	20,017	24,006
10	Average Jurisdictional Rate Base	2,713	5,427	5,427	8,203	7,247	(309)	5,724	12,386	5,258	10,670	22,012
11	Pre-Tax Weighted Cost of Capital	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%
12	Financing Costs on Deferred Amortization	-	-	-	-	19	59	101	139	177	221	276
13	Financing Costs on Rate Base	19	39	39	58	52	(2)	41	88	37	76	157
14	Total Deferred Costs Including Financing Costs	19	39	39	58	7,436	7,702	8,191	6,614	8,083	9,364	12,055
											Total	59,601

2021-0254

Virginia Electric and Power Company
Rider RGGI Cash Working Capital
September 1, 2020 to December 31, 2020
(000s)

Line No.		Amount	Average Daily Amount	Expense (Lead) Lag Days	Revenue Lag	Net (Lead) Lag Days	Working Capital (Provided) Required
	Amortization Expense						
3	Allowance Amortization	-	-	-	39.1	39.1	-
4	Amortization of Regulatory Assets (Deferred Costs)	-	-	-	39.1	39.1	-
5	Pre RAC Cost Deferral	-	-	-	39.1	39.1	-
6	Pre RAC Cost Deferral - Debt Interest	(58)	(0.48)	-	39.1	39.1	(19)
7	Pre RAC Cost Deferral - Equity	(182)	(1.49)	(39.1)	39.1	-	-
8	Pre RAC Cost Deferral - JDC	(1)	(0.01)	(39.1)	39.1	-	-
12	Interest Expense	58	0.48	(90.9)	39.1	(51.9)	(25)
13	Preferred Dividends	-	-	(39.1)	39.1	-	-
14	JDC Expense	1	0.01	(39.1)	39.1	-	-
15	Income Available for Common Equity	182	1.49	(39.1)	39.1	-	-
16	Totals	-					(43)
17	Balance Sheet Items (A/P -Allowance Purchases)	13,708	37.55	-	-	-	-
18	System Cash Working Capital						(43)

2021-00162

Virginia Electric and Power Company
Rider RGGI Cash Working Capital
January 1, 2021 to July 31, 2021
(000s)

Line No.		Amount	Average Daily Amount	Expense (Lead) Lag Days	Revenue Lag	Net (Lead) Lag Days	Working Capital (Provided) Required
	Amortization Expense						
3	Allowance Amortization	-	-	-	39.1	39.1	-
4	Amortization of Regulatory Assets (Deferred Costs)	-	-	-	39.1	39.1	-
5	Pre RAC Cost Deferral	-	-	-	39.1	39.1	-
6	Pre RAC Cost Deferral - Debt Interest	(392)	(1.84)	-	39.1	39.1	(72)
7	Pre RAC Cost Deferral - Equity	(1,227)	(5.76)	(39.1)	39.1	-	-
8	Pre RAC Cost Deferral - JDC	(7)	(0.03)	(39.1)	39.1	-	-
12	Interest Expense	392	1.84	(90.9)	39.1	(51.9)	(95)
13	Preferred Dividends	-	-	(39.1)	39.1	-	-
14	JDC Expense	7	0.03	(39.1)	39.1	-	-
15	Income Available for Common Equity	1,227	5.76	(39.1)	39.1	-	-
16	Totals	-					(167)
17	Balance Sheet Items (A/P - Allowance Purchases)	69,100	378.63	-	-	-	-
18	System Cash Working Capital						(167)

Virginia Electric and Power Company
Rider RGGI Cash Working Capital
August 1, 2021 to December 31, 2021
(000s)

Line No.		Amount	Average Daily Amount	Expense (Lead) Lag Days	Revenue Lag	Net (Lead) Lag Days	Working Capital (Provided) Required
	Amortization Expense						
3	Allowance Amortization	51,123	336.15	-	39.1	39.1	13,130
4	Amortization of Regulatory Assets (Deferred Costs)	24,834	163.29	-	39.1	39.1	6,378
5	Pre RAC Cost Deferral	-	-	-	39.1	39.1	-
6	Pre RAC Cost Deferral - Debt Interest	-	-	-	39.1	39.1	-
7	Pre RAC Cost Deferral - Equity	-	-	(39.1)	39.1	-	-
8	Pre RAC Cost Deferral - JDC	-	-	(39.1)	39.1	-	-
12	Interest Expense	721	4.74	(90.9)	39.1	(51.9)	(246)
13	Preferred Dividends	-	-	(39.1)	39.1	-	-
14	JDC Expense	13	0.08	(39.1)	39.1	-	-
15	Income Available for Common Equity	2,257	14.84	(39.1)	39.1	-	-
16	Totals	78,946					19,262
17	Balance Sheet Items (A/P - Allowance Purchases)	69,100	378.63	-	-	-	-
18	System Cash Working Capital						**19,262**

2021120015

Virginia Electric and Power Company
Rider RGGI Cash Working Capital
January 1, 2022 to July 31, 2022
(000s)

Line No.		Amount	Average Daily Amount	Expense (Lead) Lag Days	Revenue Lag	Net (Lead) Lag Days	Working Capital (Provided) Required
	Amortization Expense						
3	Allowance Amortization	78,395	368.20	-	39.1	39.1	14,382
4	Amortization of Regulatory Assets (Deferred Costs)	34,767	163.29	-	39.1	39.1	6,378
5	Pre RAC Cost Deferral	-	-	-	39.1	39.1	-
6	Pre RAC Cost Deferral - Debt Interest	-	-	-	39.1	39.1	-
7	Pre RAC Cost Deferral - Equity	-	-	(39.1)	39.1	-	-
8	Pre RAC Cost Deferral - JDC	-	-	(39.1)	39.1	-	-
12	Interest Expense	628	2.95	(90.9)	39.1	(51.9)	(153)
13	Preferred Dividends	-	-	(39.1)	39.1	-	-
14	JDC Expense	11	0.05	(39.1)	39.1	-	-
15	Income Available for Common Equity	1,966	9.23	(39.1)	39.1	-	-
16	Totals	115,767					20,607
17	Balance Sheet Items (A/P - Allowance Purchases)	66,900	368.58	-	-	-	-
18	System Cash Working Capital						20,607

20112012

VIRGINIA ELECTRIC AND POWER COMPANY
Actual Cost of Capital and Capital Structure
As of December 31, 2019

Line No.	Description	Amount	Percent	Annual Cost	Embedded Cost	Weighted Cost
1	Total long-term debt	$ 12,085,529,684	44.926%	$ 538,619,437	4.457%	2.002%
2	Short-term debt (13-month average)	697,797,692	2.594%	14,591,675	2.091%	0.054%
3	Total debt	$ 12,783,327,376	47.520%	553,211,111	4.326%	2.056%
4	Total preferred stock	-	0.000%	-	0.000%	0.000%
5	Common stock	$ 5,737,401,834	21.328%		9.200%	1.962%
6	Other paid-in capital	1,112,875,284	4.137%		9.200%	0.381%
7	Retained earnings	7,168,179,892	26.647%		9.200%	2.452%
	AOCI	(29,200,805)	-0.109%		9.200%	-0.010%
8	Adjustments	17,014,963	0.063%		9.200%	0.006%
9	Total common equity	$ 14,006,271,168	52.066%		9.200%	4.790%
	Job development tax credits					
10	Allocation: debt	$ 51,492,357	0.191%		4.457%	0.009%
11	Allocation: preferred stock	-	0.000%		0.000%	0.000%
12	Allocation: equity	59,675,987	0.222%		9.200%	0.020%
13	Total Job development tax credits	$ 111,168,344	0.413%		7.003%	0.029%
14	Total Capital	$ 26,900,766,888	100.000%			6.8755%

Attachment 74

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, AUGUST 4, 2021

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PETITION OF

VIRGINIA ELECTRIC AND POWER COMPANY CASE NO. PUR-2020-00169

For approval of a rate adjustment clause,
designated Rider RGGI, under
§ 56-585.1 A 5 e of the Code of Virginia

ORDER APPROVING RATE ADJUSTMENT CLAUSE

On November 9, 2020, Virginia Electric and Power Company ("Dominion" or "Company") filed with the State Corporation Commission ("Commission") a petition ("Petition") for approval of a rate adjustment clause, designated Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia ("Code").[1] Through its Petition, Dominion requested approval to recover projected and actual costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide ("CO_2") emissions.[2]

In May 2019, the Virginia Department of Environmental Quality ("DEQ") issued a final rule establishing a state carbon regulation program linked to RGGI (the "DEQ Carbon Rule" or "Rule"). Although the DEQ Carbon Rule was finalized in 2019, language in the state budget bill prohibited DEQ from continued work on the Rule. During its 2020 Regular Session, the General Assembly passed the Clean Energy and Community Flood and Preparedness Act, which authorized Virginia to become a full participant of RGGI and authorized DEQ to implement the DEQ Carbon Rule.[3] The legislation became effective July 1, 2020. With the passage of this

[1] On December 4, 2020, the Company filed an updated Schedule 46, completing its Petition.

[2] Ex. 2 (Petition) at 1.

[3] 2020 Va. Acts Ch. 1219 and 1280.

legislation, DEQ revised the DEQ Carbon Rule to clarify that the Commonwealth will join RGGI in 2021.

The revenue requirement for Rider RGGI in the instant proceeding includes only a Projected Cost Recovery Factor ("Projected Factor").[4] Beginning with the next filing, which the Company expects to make in 2021, the total revenue requirement will include both a Projected Factor and an Actual Cost True-Up Factor ("True-Up Factor"). No True-Up Factor is included in this proceeding because this filing represents the initial request for cost recovery.[5] In this proceeding, the Company seeks approval of a total revenue requirement of $168,260,000 for the rate year of August 1, 2021, to July 31, 2022 ("Rate Year").[6]

If the proposed Rider RGGI for the Rate Year is approved as filed, the impact on customer bills would depend on the customer's rate schedule and usage. According to Dominion, implementation of its proposed Rider RGGI on August 1, 2021, would increase the monthly bill of a residential customer using 1,000 kilowatt-hours per month by approximately $2.39.[7]

On December 11, 2020, the Commission issued an Order for Notice and Hearing that, among other things: docketed the Petition; required the Company to publish notice of the Petition; gave interested persons the opportunity to comment on, or participate in, the proceeding; scheduled public evidentiary hearings to convene on April 27 and 28, 2021; and directed the Commission Staff ("Staff") to investigate the Petition and file testimony and exhibits containing its findings and recommendations. The Virginia Committee for Fair Utility Rates

[4] Ex. 2 (Petition) at 5.

[5] *Id.*

[6] *Id.*

[7] *Id.* at 6.

("Committee"); Appalachian Voices; the Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel"); and the Board of Supervisors of Culpeper County filed notices of participation.

On March 11, 2021, the Commission entered an Order appointing a Hearing Examiner to conduct all further proceedings on behalf of the Commission. On March 24, 2021, a Hearing Examiner's Ruling directed that the April 28, 2021 hearing would be convened virtually due to the ongoing COVID-19 emergency.

On April 27, 2021, a hearing was convened to receive public witness testimony telephonically, as scheduled. One member of the public signed up to testify but did not answer his phone to provide testimony.

On April 28, 2021, a hearing to receive the testimony and evidence of the parties and Staff was convened, as scheduled, using Microsoft Teams. The Company, Appalachian Voices, the Committee, Consumer Counsel and Staff participated in the hearing. On May 19, 2021, Dominion, Appalachian Voices, Staff, Consumer Counsel, and the Committee filed post-hearing briefs.

On June 2, 2021, the Report of D. Mathias Roussy, Jr., Hearing Examiner ("Report") was issued. In the Report, the Hearing Examiner recommended that the Company's proposed Rider RGGI be approved, with an initial Rider RGGI rate designed to recover $167.76 million.[8]

The Hearing Examiner made the following additional findings and recommendations:

(1) By the close of the record, Dominion had spent approximately $40 million ($32 million Virginia jurisdictional) to purchase CO_2 allowances that effectively cover the Company's regulated emissions for the first three months of 2021.

[8] Report at 35.

(2) Dominion will need to purchase many more CO_2 allowances through the end of the [R]ate [Y]ear (July 31, 2022), although the exact prices or quantities of such additional purchases cannot be known at this time.

(3) Record evidence, including actual CO_2 allowance prices in 2021, indicates the $6.84 allowance price used to calculate the proposed Rider RGGI revenue requirement could be too low. However, CO_2 allowance prices fluctuate and any price differentials (higher or lower) can be trued-up in future Rider RGGI proceedings.

(4) Dominion's proposed use of weighted averages to calculate the cost of allowance consumption reasonably incorporates the actual prices of CO_2 allowance purchases by Dominion.

(5) Like CO_2 allowance price differentials discussed above, adjustment clause recovery allows any quantity differentials (higher or lower) to be trued-up in future Rider RGGI proceedings.

(6) Dominion will not incur any costs through the end of the [R]ate [Y]ear to build a CO_2 allowance bank. An allowance bank, if implemented temporarily at the end of a control period, generally appears to be a reasonable measure to ensure CO_2 compliance and avoid significant penalties for non-compliance. However, Dominion should provide sufficient support for any cost recovery associated with an allowance bank in any future proceeding in which it seeks to recover such costs.

(7) Dominion will incur financing costs associated with a CO_2 allowance inventory, cash working capital, and deferred balances.

(8) The Commission has previously authorized adjustment clause recovery under Code § 56-585.1 A 5 e for financing costs associated with an emissions allowance inventory, cash working capital, and deferred balances.

(9) Legislation enacted in 2020 does not appear to limit RGGI compliance costs to only the "sticker price" of allowances, but the Commission has not previously interpreted this legislation. Should the Commission interpret this legislation to include such a limitation, approximately $4.95 million (3%) of the proposed $167.76 million revenue requirement request should be recoverable through base rates, rather than Rider RGGI.

(10) It is reasonable for Dominion to obtain CO_2 allowances from both the RGGI auctions and the secondary market.

(11) While Dominion's RGGI compliance approach generally appears to be a reasonable way to manage operational facilities in the short-term, Dominion's Petition was not presented with analysis indicating such short-term compliance is part of a least-cost strategy that integrates the requirements of RGGI and other legal requirements, including new

mandatory [Renewable Energy Portfolio Standards ("RPS")] requirements that could affect CO_2 emissions. The Commission recently directed Dominion to conduct and present this type of analysis in separate proceedings and the instant proceeding offers the Commission the opportunity to provide guidance on whether such analysis should also be presented in Rider RGGI proceedings.

(12) The Commission can approve a projected cost Rider RGGI revenue requirement in the instant case, based largely on projected need and prices forecasted at the outset of a three-year compliance period, without foreclosing the Commission's authority to review, in future Rider RGGI proceedings, the reasonableness or prudence of expenditures once they have actually been incurred and are known.

(13) If RGGI compliance cost recovery is not approved until a future Rider RGGI proceeding, Dominion's ongoing CO_2 allowance costs would accumulate and could result in a significant deferral balance with a larger ratepayer impact.

(14) The energy allocation and rate design for Rider RGGI are reasonable.[9]

NOW THE COMMISSION, having considered this matter, is of the opinion and finds as follows.

The Commission finds that Rider RGGI meets the statutory requirements for approval of a RAC under Code § 56-585.1 A 5 e. The Commission herein approves a revenue requirement, as recommended by the Hearing Examiner, of $167.76 million.

Statutory Authority

Code § 56-585.1 A 5 e states in relevant part as follows:

5. A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of the following costs:
. . .

e. Projected and actual costs of projects that the Commission finds to be necessary . . . to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the costs of allowances purchased through a market-based trading program for

[9] *Id.* at 34-35.

> [CO_2] emissions. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations;

Allowance Bank

In its Petition, Dominion identified its plan to obtain a quantity of allowances that would be 10% to 20% above the Company's projected annual compliance obligation.[10] According to the Company, the purpose of this planned "bank" is "to protect customers from forecast uncertainty, price volatility, and noncompliance penalties."[11] Appalachian Voices agreed that it is "wise for the Company to develop a banking strategy and to consider the procurement of an appropriate amount of excess allowances as a hedge against market volatility and unexpected increases in demand for energy," but argued that a 10% to 20% level for such bank is unreasonable.[12]

The Hearing Examiner noted that Dominion did not plan to implement an allowance bank during the Rate Year and recommended that the Commission evaluate any banked allowances during future Rider RGGI proceedings.[13]

In its comments on the Hearing Examiner's Report, Appalachian Voices argued that the Company's proposed 10% to 20% allowance bank is not supported by any economic analysis. Appalachian Voices requested that the Commission find that any purchases made to establish an allowance bank are not approved in this case, and the Company must provide detailed economic analysis to support any future request for a bank.[14]

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[10] Ex. 4 (Hitch direct) at 8.

[11] Ex. 25 (Hitch rebuttal) at 10.

[12] Ex. 15 (Rábago) at 8, 15.

[13] Report at 25.

[14] Appalachian Voices Comments at 13-14.

We agree with the Hearing Examiner and will direct the Company, in any applicable future Rider RGGI proceeding, to identify and provide support for any banked allowances.[15]

Financing Costs

Dominion's Petition requested a revenue requirement, as corrected by Staff, of approximately $168 million. The Hearing Examiner's Report notes that the actual cost of the allowances the Company projects to obtain through the end of the Rate Year is higher than this amount.[16] The proposed revenue requirement instead includes only the costs of allowances that would be both obtained and consumed by the end of the Rate Year, plus the financing of projected allowances that would be purchased but not yet consumed.[17] Dominion proposed to recover the financing costs for purchased allowances through a proposed return on a rate base that consists of: (a) allowance inventory, which is the positive or negative balance of purchased allowances minus required allowances; (b) cash working capital; and (c) deferred costs. The financing costs represent approximately $5 million of the $168 million revenue requirement.[18]

Dominion argued that financing costs are part of "the costs of allowances purchased through a market-based trading program for [CO_2] emissions," and are therefore recoverable as part of Rider RGGI pursuant to Code § 56-585.1 A 5 e.[19]

Staff asserted that the Commission has discretion to decide whether to approve financing costs under Code § 56-585.1 A 5 e and that the statute "neither expressly forbids, nor explicitly

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[15] *See* Report at 26.

[16] *Id.* at 26. According to the Report, the actual costs of the allowances is approximately $174 million, as estimated in the Petition, or $199 million, based on updated estimates. *Id.* at n.199.

[17] *Id.* at 26-27.

[18] *Id.* at 27; *See, e.g.*, Tr. at 150, 154.

[19] Dominion Post-Hearing Brief at 8-9.

requires, that the costs recovered through a rate adjustment clause related to RGGI participation include the financing costs associated with such participation."[20] Staff noted that the Commission has previously rejected financing costs in cases conducted under Code § 56-585.1 A 4.[21] Consumer Counsel recognized the Commission's discretion in this area and argued that the Commission should exercise this discretion by excluding the financing costs from recovery under Rider RGGI.[22]

The Committee, on the other hand, stated that there is no authority to support Staff's argument that the Commission has discretion to include financing costs, arguing that Code § 56-585.1 A 5 e does not include the terms "carrying cost" or "financing cost" and arguing that the statute does not suggest that "any costs associated with, or even resulting from, an underlying compliance cost were intended to be recovered through a rider such as Rider RGGI."[23]

The Hearing Examiner concluded that "the legal issue of whether allowance financing costs should be approved for recovery in this case does not appear to implicate Commission discretion."[24] The Hearing Examiner further concluded that financing costs of allowances procured are a part of the costs of allowances recoverable under the Code, noting that Code § 56-585.1 A 5 e

> has provided rate adjustment clause recovery of environmental compliance expenses and a return on environmental compliance rate base items. For adjustment clause recovery under this statute, environmental compliance rate base items have included, among other things, environmental allowance inventory, cash working capital, and deferred balances. These and other costs have been considered the "cost of [compliance] projects" upon a finding that they were

[20] Staff Post-Hearing Brief at 2.

[21] Tr. at 160-162.

[22] Consumer Counsel Post-Hearing Brief at 5-7.

[23] Committee Post-Hearing Brief at 3.

[24] Report at 28.

> necessary to comply with environmental laws or regulations, unless the applicant utility failed to demonstrate (1) the actual level of compliance costs, or (2) the prudence or reasonableness of costs.[25]

We agree with Consumer Counsel that nothing in Code § 56-585.1 A 5 e expressly forbids the costs recovered through a rate adjustment clause related to RGGI participation from including the financing costs associated with such participation. We agree with the Hearing Examiner and Staff that these financing costs are "costs of allowances purchased through a market-based trading program for [CO_2] emissions" and are therefore part of the Company's costs of complying with the DEQ Carbon Rule.[26] We will, therefore, approve recovery of the approximately $5 million in financing costs as part of the Rider RGGI revenue requirement.

Statutory Standards

Appalachian Voices requested that the Commission reject the Petition, arguing that the Petition "was not presented with analysis indicating such short-term compliance is part of a least-cost strategy that integrates the requirements of RGGI and other legal requirements, including new mandatory RPS requirements that could affect CO_2 emissions."[27] Appalachian Voices further argued that "[a] sophisticated, vertically-integrated utility like the Company, seeking $167 million from its customers, should be required to perform sophisticated economic analysis to develop and support an optimized procurement strategy."[28]

The Company responded that the focus of this proceeding is short-term. While long-term planning occurs in the Company's Integrated Resource Plan and RPS proceedings, this

[25] *Id.* at 29 (internal footnotes omitted).

[26] *See id.* at 30; Ex. 18 (Carr) at 4.

[27] Ex. 15 (Rábago) at 12; Appalachian Voices Post-Hearing Brief at 8-12.

[28] Appalachian Voices Comments at 15-16.

proceeding is limited to the projected and actual costs of compliance with the DEQ Carbon Rule during the Rate Year, subject to true-up annually.[29]

The Hearing Examiner concluded that "Dominion's RGGI compliance approach, in general, [is] a reasonable way to manage operational facilities in the short-term" but agreed with Appalachian Voices that the Petition did not include analysis that this compliance was part of a long-term, least-cost strategy.[30] The Hearing Examiner recommended that the "instant proceeding offers the Commission the opportunity to provide guidance on whether such analysis should likewise be presented in Rider RGGI proceedings."[31]

We find that the Code provides the standard for review of Rider RGGI costs. In each case, the Company must establish that the costs included in the requested revenue requirement are reasonably and prudently incurred and are "costs of allowances purchased through a market-based trading program for [CO_2] emissions. . . . necessary to comply with [state or federal] environmental laws or regulations."[32] We agree with the Hearing Examiner that the Company's compliance approach, as presented in the record of this case, is "a reasonable way to manage operational facilities in the short-term."[33] Consequently, we find that the costs requested by the Company in this proceeding comply with this statutory requirement. The Company will continue to bear the burden of establishing that this standard has been met in future proceedings.

In addition, the Commission recognizes that Dominion's RGGI compliance is not isolated from its RPS plans, which are also required by statute. Indeed, in Dominion's recent RPS

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[29] Dominion Comments at 6-8.

[30] Report at 31.

[31] *Id.* at 32.

[32] See Code §§ 56-585.1 A 5 e, 56-585.1 D.

[33] Report at 31, 35.

proceeding, the Commission expressly directed the Company to include in future RPS filings a least-cost plan that meets applicable carbon regulations, including Virginia's participation in RGGI.[34] Similarly, we herein direct the Company to include in future Rider RGGI filings an analysis of how its RGGI compliance corresponds to its RPS plan filings.

Based on the foregoing, we find that the statutory requirements for a rate adjustment clause under Code § 56-585.1 A 5 e have been met. We further agree with the Hearing Examiner that the revenue requirement for the initial Rate Year should be $167.76 million, subject to actual cost true-up in future cases that may include an evaluation of the reasonableness and prudence of actual allowance costs incurred by the Company.[35]

Accordingly, IT IS ORDERED THAT:

(1) The findings and recommendations set forth in the Hearing Examiner's Report are adopted, as modified herein.

(2) Rider RGGI is approved, as discussed herein, with a revenue requirement of $167,759,000 for the Rate Year.

(3) Rider RGGI, as approved herein, shall be effective for usage on and after September 1, 2021.

(4) The Company forthwith shall file a revised Rider RGGI and supporting workpapers with the Clerk of the Commission and with the Commission's Divisions of Public Utility Regulation and Utility Accounting and Finance, as is necessary to comply with the directives set forth in this Order. The Clerk of the Commission shall retain such filings for public inspection in person and on the Commission's website: scc.virginia.gov/pages/Case-Information.

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[34] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing 2020 RPS Proceeding for Virginia Electric and Power Company*, Case No. PUR-2020-00134, Doc. Con. Ctr. No. 210440236, Final Order at 6 n.15 (Apr. 30, 2021).

[35] *See* Report at 32-33.

(5) This case is dismissed.

JAGDMANN, Commissioner, concurs:

I agree in all respects with the majority opinion. A least-cost plan for compliance with RGGI and RPS requirements should be included in future Rider RGGI and RPS plan filings. While there may be reasons for a utility's deviation from a least-cost plan for either or both programs, additional information on the cost of compliance with these requirements will be informative.

This discussion, however, raises the question of the need for two separate and distinct modes for achieving carbon reduction. RGGI is a CO_2 emissions cap-and-trade program[36] that currently is expected to cost Dominion's Virginia jurisdictional ratepayers approximately $3 billion through 2045.[37] While there tends to be much discussion of the revenues RGGI "generates" for various programs,[38] RGGI does not create this money. Rather, RGGI directly

[36] Code § 10.1-1329 defines RGGI as "the program to implement the memorandum of understanding between signatory states dated December 20, 2005, and as may be amended, and the corresponding model rule that established a regional carbon dioxide electric power sector cap and trade program." RGGI defines itself as "a cooperative, market-based effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia to cap and reduce CO_2 emissions from the power sector." *See* https://www.rggi.org/.

[37] Report at 13-14 (citing Ex. 18 (Carr) at 5 and Appendix page 12) (showing total Rider RGGI required revenues for the Virginia jurisdiction of approximately $2.946 billion, excluding financing costs). As reported to the General Assembly's Commission on Electric Utility Regulation and others in a report dated August 18, 2020, Dominion identified potential Virginia regulated entity capital investments of $50-59 billion from 2020-2035. While this total includes items outside of the Virginia Clean Economy Act ("VCEA"), 2020 Va. Acts chs. 1193, 1194, the renewable portfolio standard program related categories of solar, onshore wind, offshore wind, and energy storage investments account for $34-43 billion of such investment. *Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant to § 56-596 B of the Code of Virginia* at 9-10 (Aug. 18, 2020), available at: https://rga.lis.virginia.gov/Published/2020/RD282/PDF.

[38] Pursuant to Code § 10.1-1330 C: (i) 45% of the revenue is allocated to assisting localities and residents affected by recurrent flooding, sea level rise, and flooding from severe weather events; (ii) 50% of the revenue is allocated to supporting Department of Housing and Community Development ("DHCD") low-income energy efficiency programs, including programs for eligible housing developments; (iii) 3% is used to cover administrative expenses and to carry out statewide climate change planning and mitigation activities; and (iv) the remaining 2% is used by DHCD, in partnership with the Department of Mines, Minerals and Energy ("DMME") to administer and implement the low-income energy efficiency programs.

charges generators, including utilities such as Dominion who in turn bill ratepayers for these very costs.

RGGI requirements and the associated costs are in addition to the requirements and associated costs of the VCEA which, among other things, requires participation by Dominion and Appalachian Power Company ("Appalachian") in RPS programs.[39] For Dominion, the RPS program requirements attach to 14% of total electric energy sales in 2021 (based on the energy sold in the previous calendar year), steadily increasing to 52% in 2033 and continuing to 100% in 2045.[40] The VCEA is highly prescriptive as to how these requirements are to be met. For example:

- By December 31, 2035, Dominion must "petition the Commission for necessary approvals to (i) construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes" of 16,100 megawatts ("MW") of onshore wind and solar generation.[41] There are interim requirements for years 2024, 2027, and 2030 for petitions of, respectively 3,000 MW, another 3,000 MW, and an additional 4,000 MW of such generation.[42]
- By December 31, 2035, Dominion must petition the Commission to construct or purchase one or more offshore wind facilities of up to 5,200 MW capacity.[43]

[39] *See* Code § 56-585.5 C.

[40] *Id.*

[41] Code § 56-585.5 D 2.

[42] Code § 56-585.5 D 2 a. b. and c.

[43] Code § 56-585.5 D 2.

- There is similar language requiring Dominion to petition to construct or acquire 2,700 MW of energy storage capacity.[44]
- If the utility is unable to meet the compliance obligations of the RPS statute or if the cost of renewable energy certificates ("RECs") exceeds $45 per megawatt-hour ("MWh"), utilities shall make $45 per MWh deficiency payments for any shortfall.[45] The deficiency payments go to DMME to administer and direct to job training programs in historically economically disadvantaged communities, energy efficiency measures for public facilities, renewable energy programs located in historically economically disadvantaged communities, and administrative costs.[46]

Utilities subject to VCEA requirements are allowed to pass through the costs of compliance to ratepayers. Several avenues are provided for such cost recovery, namely: (i) dollar-for-dollar recovery of all costs through one or more rate adjustment clauses;[47] (ii) the potential to accelerate cost recovery from customers of the aggregate amount of approved capital investment in solar, onshore wind, or offshore wind generating facilities as a customer credit reinvestment offset in a Triennial Review case;[48] or (iii) the opportunity to recover such costs

[44] Code § 56-585.5 E 2.

[45] Code § 56-585.5 D 5. The deficiency payment is greater, $75 per MWh, "for any shortfall in procuring RECs for solar, wind, or anaerobic digesters located in the Commonwealth" for resources 1 MW and lower. Further, the amount of any deficiency payment increases by one percent annually after 2021. *Id.*

[46] *Id.*

[47] Code § 56-585.1 A 5 d (for recovery of the cost of complying with RPS program requirements not recoverable under Code § 56-585.1 A 6); Code § 56-585.1 A 5 e (for recovery of, among other things, the costs of allowances purchased through a market-based trading program for CO_2 emissions); and Code § 56-585.1 A 6 (for recovery of the costs of, among other things, solar, onshore wind, and offshore wind facilities).

[48] Code §§ 56-585.1 A 6 and A 8 d.

over the lives of the facilities through the utility's base rates.[49] In other words, customers will pay for all the utility's RPS costs, whether through a rate adjustment clause or base rates. As noted above, the cost to ratepayers for VCEA compliance, along with associated necessary transmission and distribution infrastructure builds and upgrades, will be significant.[50]

This is not to question the policy of the General Assembly to achieve specific carbon reductions.[51] Indeed on April 30th of this year, in our Final Orders on the annual RPS plans for both Dominion and Appalachian we stated, "[W]e have exercised the Commission's delegated discretion in a manner that faithfully implements the VCEA requirements that include carbon reduction, while best protecting consumers who expect and deserve reliable and affordable service."[52] It is appropriate, however, to note potential costly duplications that may impede realization of the General Assembly's intent. The VCEA plainly states that the RPS program requirements for Dominion shall be 100% by 2045. Thus, it remains unclear whether the significant cost required for participation in an additional cap-and-trade program – which is

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[49] Code § 56-585.5 D. Also pursuant to this Code provision, costs related to "the purchase of energy, capacity, or environmental attributes from facilities owned by the persons other than the utility required by the subsection" are recoverable under either base rates or the Company's fuel factor.

[50] *See* n.37, *supra*.

[51] *See Old Dominion Comm. for Fair Util. Rates v. State Corp. Comm'n,* 294 Va. 168, 175 (2017) ("The Commission rejected the public policy arguments against the statute . . . [and] focused instead on the purely legal issue of whether Old Dominion had carried its burden of overcoming the presumption in favor of the statute's constitutionality . . . . Thus, its 'duty in this case,' the Commission explained, 'is to decide the legal question of constitutionality without regard to our public-policy preferences and not to conflate the two.'") (affirming and quoting *Petition of The Old Dominion Committee for Fair Utility Rates v. Appalachian Power Company, For a declaratory judgment and an order requiring biennial review filings*, Case No. PUE-2016-00010, 2016 S.C.C. Ann. Rept. 357, 362, Final Order (July 1, 2016)).

[52] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing 2020 RPS Proceeding for Virginia Electric and Power Company*, Case No. PUR-2020-00134, Doc. Con. Cen. No. 210440236, Final Order at 4 (Apr. 30, 2021); *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing 2020 RPS Proceeding for Appalachian Power Company*, Case No. PUR-2020-00135, Doc. Con. Cen. No. 210440238, Final Order at 3 (Apr. 30, 2021).

expected to cost customers billions of dollars – are necessary for Dominion's and Appalachian's ratepayers to bear in order to achieve the General Assembly's carbon reduction objectives.[53]

A COPY hereof shall be sent electronically by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the Commission.

[53] RGGI extends to more generators than the two utilities (Dominion and Appalachian) required to participate in RPS programs. An option that would move Dominion and Appalachian ratepayers closer to neutral would be for revenues associated with their RGGI compliance to be returned and then credited to ratepayers.

Attachment 75

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

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Case Number (if already assigned)	PUR-2021-00281
Case Name (if known)	Petition of Virginia Electric and Power Company for revision of rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia
Document Type	EXPE
Document Description Summary	Virginia Electric and Power Company's Rider RGGI Annual Update Filing
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December 6, 2021

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State Corporation Commission
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Richmond, Virginia 23219

Petition of Virginia Electric and Power Company for revision of rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia
Case No. PUR-2021-00281

Dear Mr. Logan:

Enclosed for electronic filing in the above-captioned proceeding, please find *Virginia Electric and Power Company's Rider RGGI Annual Update Filing.*

Please do not hesitate to contact me if you have any questions in regard to this filing.

Highest regards,

/s/ Elaine S. Ryan

Elaine S. Ryan

enc.

cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.
Paul E. Pfeffer, Esq.
David J. DePippo, Esq.
Timothy D. Patterson, Esq.
Dan Bumpus, Esq.

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Dominion Energy®

Petition, Direct Testimony, Exhibits and Schedules of Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

For revision of rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia

Volume 1 of 1

Case No. PUR-2021-00281

Filed: December 6, 2021

2021-0281

Petition of Virginia Electric and Power Company
For revision of rate adjustment clause: Rider RGGI,
pursuant to § 56-585.1 A 5 e of the Code of Virginia
Case No. PUR-2021-00281

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E-2021-00281

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY	)	
	)	Case No. PUR-2021-00281
For revision of rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia	)	

VIRGINIA ELECTRIC AND POWER COMPANY'S
RIDER RGGI ANNUAL UPDATE FILING

Pursuant to § 56-585.1 A 5 e ("Subsection A 5 e") of the Code of Virginia ("Va. Code") and the State Corporation Commission of Virginia's ("Commission") Rules Governing Utility Rate Applications and Annual Informational Filings (the "Rate Case Rules"),[1] Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), by counsel, hereby submits this annual update filing with respect to its rate adjustment clause ("RAC" or "Rider"), designated Rider RGGI, approved to recover costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide ("CO_2") emissions, a program in which the Company is required to participate. In support of its petition ("Petition"), the Company respectfully shows as follows:

GENERAL INFORMATION

1. Dominion Energy Virginia is a public service corporation organized under the laws of the Commonwealth of Virginia furnishing electric service to the public within its certificated service territory. The Company also supplies electric service to non-jurisdictional customers in Virginia and to the public in portions of North Carolina. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to

[1] 20 VAC 5-204-10, *et seq.*

2121-2168-4568

the public for compensation. The Company is also a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. The Company is an operating subsidiary of Dominion Energy, Inc.

2. The Company's address is:

Virginia Electric and Power Company
120 Tredegar Street
Richmond, Virginia 23219

3. The names, addresses, and telephone numbers of the attorneys for the Company are:

Paul E. Pfeffer
David J. DePippo
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BACKGROUND

4. Initiated in 2009, RGGI is the first mandatory market-based program in the United States to reduce greenhouse gas emissions. RGGI is a collaborative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia to cap and reduce CO_2 emissions from the

power sector. CO_2 allowances are obtained by RGGI participants through quarterly, regional auctions.

5. In May 2019, the Virginia Department of Environmental Quality ("DEQ") issued a final rule establishing a state carbon regulation program linked to RGGI (the "DEQ Carbon Rule" or "Rule"). The DEQ Carbon Rule capped CO_2 emissions for Virginia at 27.1 million short tons for calendar year 2021 and decreases the emissions cap annually by approximately 3% to achieve a 30% reduction from 2020 levels to a level of 19.6 million short tons in 2030. Emission sources subject to the Rule are required to obtain and surrender a CO_2 emission allowance for every short ton of CO_2 emitted during a control period.

6. The Company owns regulated emissions sources, so it must comply with RGGI.

7. Va. Code § 56-585.1 A 5 e permits cost recovery related to compliance with RGGI and establishes the applicable standard of review:

> A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of . . . [p]rojected and actual costs of projects that the Commission finds to be necessary . . . to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the costs of allowances purchased through a market-based trading program for carbon dioxide emissions. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations.

8. On August 4, 2021, in Case No. PUR-2020-00169 ("2020 Rider RGGI Proceeding"), the Commission issued its Order Approving Rate Adjustment Clause ("Rider RGGI Order"), approving Rider RGGI to be effective for usage on and after September 1, 2021.[2]

[2] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No PUR-2020-00169, Order Approving Rate Adjustment Clause at 11 (Aug. 4, 2021).

2022-0169

Subsequently, the Commission suspended the Rider RGGI Order on August 25, 2021 pending consideration of a Petition for Reconsideration or Clarification. On November 17, 2021, by its Order on Reconsideration, the Commission lifted the suspension of the Rider RGGI Order without modification of its initial order.

RIDER RGGI

9. For the period beginning September 1, 2022 and ending August 31, 2023 (the "Rate Year"), the Company estimates it will require approximately 19 million CO_2 allowances to cover CO_2 emissions from its Virginia-based generation fleet.

10. Generally, to meet its obligations under RGGI, the Company is following a programmatic approach by purchasing most of the required allowances in the RGGI quarterly auctions and using the secondary market to fill any auction deficiencies. More specifically, Dominion Energy Virginia plans to acquire approximately 25% of the forecasted annual allowance requirement in each of the quarterly auctions. If the Company fails to secure approximately 25% in an auction, the Company will look to purchase allowances in the secondary market. The Company's compliance strategy is not based on any price outlook. Instead, the Company intends to follow a programmatic, auction-based approach to compliance. The Company may adjust its compliance strategy as needed to adapt to changes in the structure of the RGGI program.

11. The Company has assumed a weighted average price of $10.53 per allowance. This assumption is based on December ICE futures contracts for 2021 and 2022 and the ICF International, Inc. forward price curve for 2023.

12. The Company's RAC revenue requirement in this proceeding includes the Projected Cost Recovery Factor and an Interim Correction Factor. It is anticipated that the

2021-0306

Actual Cost True-up Factor for calendar year 2021 will not be included as part of the RGGI revenue requirement until the 2022 annual update filing, since the Rider RGGI implementation was delayed due to the Petition for Reconsideration or Clarification in the 2020 Rider RGGI Proceeding. The Projected Cost Recovery Factor calculation results in the operating income necessary for recovery of amortization expense for CO_2 allowances as well as projected financing costs on the unamortized purchased CO_2 allowance balances. The Interim Correction Factor is proposed in this proceeding in an effort to minimize the impacts of carrying costs on future known under-recoveries that resulted from greater than anticipated allowance costs. The Interim Correction Factor will recover from, or credit to, any under/over collection of actual known costs and updated projected allowance usage for the months of September 1, 2020 through July 31, 2022, the end of the initial Rate Year for Rider RGGI. The actual and known costs from September 2020 through September 2021, and the updated projections from October 2021 through July 2022 are compared to the original projected and deferred amounts from the 2020 Rider RGGI filing for the same period. This difference becomes the Interim Correction Factor to be recovered from customers during the proposed September 1, 2022 through August 31, 2023 Rate Year. When the Actual Cost True-Up Factor is included, it will recover from, or credit to, customers any under- or over-recovery of costs from the most recently completed calendar year. Actual revenues recovered during the test year are compared to actual costs incurred during the test year. Any difference in these amounts becomes the Actual Cost True-Up Factor credited to, or recovered from, customers through the total revenue requirement requested for recovery during the rate year.

13. The total revenue requirement requested for recovery in this Rider RGGI Petition for the Rate Year beginning September 1, 2022, is $323,411,000.

14. For purposes of this Petition, and consistent with the Commission's November 18, 2021 Final Order in the Company's triennial review proceeding in Case No. PUR-2021-00058,[3] the Company is utilizing the approved ROE of 9.35% for the period subsequent to the date of that Final Order. For the time periods prior to the Final Order in that case, the Company is utilizing a ROE of 9.2%, as approved by the Commission in Case No. PUR-2019-00050.[4]

15. The implementation of the proposed Rider RGGI on September 1, 2022, will increase the residential customer's monthly bill, based on 1,000 kWh per month, by $1.98. Including the increase associated with this annual update, the total Rider RGGI impact on the typical bill of a residential customer is $4.37.

RGGI COMPLIANCE AND RPS DEVELOPMENT PLAN MODELING

16. In the 2020 Rider RGGI Order, the Commission directed the Company to "include in future Rider RGGI filings an analysis of how its RGGI compliance corresponds to its RPS plan filings."[5] The Company has prepared this analysis and included it as Exhibit 1 to this Petition. Exhibit 1 is sponsored by Company Witness Jeffrey D. Matzen.

SUPPORTING TESTIMONY AND FILING SCHEDULES 3, 4, 5, 8, AND 46

17. The Company's Petition is supported by the pre-filed direct testimonies of Company Witnesses George E. Hitch, Jeffrey D. Matzen, C. Alan Givens, and Paul B. Haynes.

A. Filing Schedules 3, 4, 5, and 8

18. Section 60 of the Rate Case Rules provides that rate adjustment clause

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[3] *Application of Virginia Electric and Power Company For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUR-2021-00058, Final Order (Nov. 18, 2021).

[4] *Application of Virginia Electric and Power Company For the determination of the fair rate of return on common equity pursuant to § 56-585.1:1 C of the Code of Virginia*, Case No. PUR-2019-00050, Final Order (Nov. 21, 2019).

[5] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No PUR-2020-00169, Order Approving Rate Adjustment Clause at 11 (Aug. 4, 2021).

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"applications requiring an overall cost of capital shall include Schedules 3, 4, 5, and 8." The Company is filing with this Petition, Filing Schedules 3, 4, 5, and 8, as follows. These filing schedules are sponsored by Company Witness Givens.

19. Filing Schedules 3 and 3A provide the capital structure and cost of capital statements applicable to Rider RGGI. Filing Schedule 4 provides schedules of long-term debt, preferred stock, investment tax credits, and other components of ratemaking capital for the filing. Filing Schedule 5 provides the schedule of short-term debt, revolving credit agreements, and similar short-term financing arrangements. Filing Schedule 8 provides the proposed cost of capital statement for Rider RGGI.

B. Filing Schedule 46

20. Rule 60 of the Rate Case Rules provides than an application filed pursuant to Subsection A 5 "shall include Schedule 46 as identified and described in 20 VAC 5-204-90, which shall be submitted with the utility's direct testimony." The Company is filing with this Petition, Filing Schedule 46, as follows:

a. Company Witnesses Hitch and Matzen co-sponsor Schedule 46A, consisting of Statements 1 and 2. Schedule 46A, Statement 1, provides projected costs associated with Rider RGGI, while Schedule 46A, Statement 2, provides documentation supporting the projected costs.

b. Company Witness Givens sponsors Schedule 46B, consisting of Statement 1, which provides the annual revenue requirement information for the proposed rate year, Statement 2, which provides projected revenue requirement information for years 2023-2046, and Statement 3, which provides documentation to support the projected annual revenue requirements.

c. Company Witness Haynes sponsors Schedule 46C, consisting of Statements 1-2, which provide details of the Company's methodology for allocating the Rider RGGI revenue requirement.

COMPLIANCE WITH RULE 10 OF THE RATE CASE RULES

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21. The Company's Petition for approval of Rider RGGI complies with the requirements contained in Rule 10 of the Rate Case Rules. In accordance with Rule 10 A, the Company filed with the Commission on October 7, 2021, the Company's notice of intent to file this Petition under Va. Code § 56-585.1 A 5. Copies of this Petition, to the extent required by Rule 10 J, along with the additional information required by Rule 10 J, have been served upon the persons addressed in that Rule. A complete copy of this Petition has been served upon the Office of the Attorney General's Division of Consumer Counsel in conformity with Rule 10 J. Also included with and following this Petition, pursuant to Rule 10, is a table of contents of this filing, including testimony and schedules.

22. Beyond the initial Petition, Rate Case Rule 10 J requires the Company to serve copies of certain information related to Dominion Energy Virginia's rate proceedings upon local officials electronically to the extent official email addresses are available, or via first class mail or personal delivery if electronic delivery is not possible. The Company will comply with this requirement in conjunction with the Commission's forthcoming procedural order.

CONCLUSION

WHEREFORE, Dominion Energy Virginia respectfully requests that the Commission (i) approve the proposed Rider RGGI under Va. Code § 56-585.1 A 5 e subject to future Rider RGGI proceedings and true-ups, effective for usage on and after September 1, 2022; (ii) approve the proposed revenue requirement, cost allocation, rate design, and accounting treatment for Rider RGGI for the Rate Year September 1, 2022 through August 31, 2023; and (iii) grant such other relief as deemed appropriate and necessary.

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Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

By: */s/ Elaine S. Ryan*
Counsel

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Counsel for Virginia Electric and Power Company

December 6, 2021

Exhibit 1

Dominion Energy Virginia's RGGI Compliance and RPS Development Plan Modeling

I. Background – VCEA

The VCEA—Senate Bill No. 851 and House Bill No. 1526 from the 2020 Regular Session of the Virginia General Assembly—became law in the Commonwealth effective July 1, 2020. Relevant to this proceeding, the VCEA (i) requires the development of renewable energy generation resources; (ii) requires the development of energy storage resources; (iii) requires the submission of an annual plan to meet the development targets; and (iv) institutes a mandatory RPS Program.

Under Va. Code § 56-585.5 D 4, the Company must submit an annual plan outlining how it intends to meet the renewable energy generation and energy storage development targets. This annual filing must contain any request for approval to construct or purchase solar or onshore wind generation under Va. Code § 56-580 D, as well as any associated requests related to cost recovery of such facilities under Va. Code § 56-585.1 A 6. The Commission must determine whether such annual filings are reasonable and prudent, giving due consideration to certain factors: (i) the RPS and carbon dioxide reduction requirements in this section, (ii) the promotion of new renewable generation and energy storage resources within the Commonwealth and associated economic development, and (iii) fuel savings projected to be achieved by the plan.

II. Background – RPS Development Plan

Dominion Energy Virginia submitted its 2020 RPS Development Plan in Case No. PUR-2020-00134 on October 30, 2020. The Commission approved the 2020 RPS Development Plan as reasonable and prudent on April 30, 2021. Subsequently, Dominion Energy Virginia submitted its 2021 RPS Development Plan on September 15, 2021 in Case No. PUR-2021-00146. In that filing, the Company affirms that the 2021 RPS Plan is consistent with Alternative Plan B from the Company's 2021 update to its 2020 Integrated Resource Plan ("2021 IRP Update") filed on September 1, 2021 in Case No. PUR-2021-00201, which is described in more detail in Part IV, below. The Company further affirms that the modeling inputs and assumptions are consistent between the 2021 IRP Update and the 2021 RPS Development Plan. The 2021 RPS Development Plan will (i) support RPS Program compliance; (ii) support carbon dioxide ("CO_2") reductions in the Commonwealth; (iii) promote new renewable energy generation and energy storage resources in the Commonwealth and the associated economic development; and (iv) result in fuel savings while maintaining reliability.

III. Background – Rider RGGI

On November 9, 2020, in Case No. PUR-2020-00169, the Company filed for approval of a rate adjustment clause, designated Rider RGGI, under Va. Code § 56-585.1 A 5 e to recover projected and actual costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for CO_2 emissions, a

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program in which the Company is required to participate. In its August 4, 2021 Order Approving Rate Adjustment Clause and its November 17, 2021 Order on Reconsideration, the Commission approved Rider RGGI, finding that the Company's compliance approach is a reasonable way to manage operational facilities in the short-term and that the costs requested in that proceeding complied with the statutory standard. The Commission further directed the Company to include in future Rider RGGI filings an analysis of how its RGGI compliance corresponds to its RPS plan filings. Dominion Energy Virginia herein presents the required analysis as part of its 2021 Annual Update to Rider RGGI.

IV. Analysis

In the 2021 IRP Update, the Company presented three alternative plans ("Alternative Plans"). Alternative Plan A presents a least-cost plan that meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA. The Company presented this Alternative Plan for cost comparison purposes only in compliance with prior Commission orders. Notably, Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. By contrast, Alternative Plan B is consistent with the 2021 RPS Development Plan.[1] Figure 1 presents the results for Alternative Plan A (*i.e.*, the "least-cost plan") and Alternative Plan B.

Figure 1: 2021 IRP Update Results for Alternative Plans A and B

	Plan A	Plan B
NPV Total ($B)	$47.8	$67.9
Approximate CO_2 Emissions from Company in 2046 (Metric Tons)	18 M	2 M
Solar (MW)	820 15-year 2,140 25-year	14,310 15-year 17,790 25-year
Wind (MW)	--- 15-year --- 25-year	5,174 15-year 5,174 25-year
Storage (MW)	--- 15-year --- 25-year	2,713 15-year 2,773 25-year
Natural Gas-Fired (MW)	970 15-year 970 25-year	--- 15-year --- 25-year
Retirements (MW)	2,567 15-year 2,567 25-year	2,561 15-year 4,792 25-year

Through PLEXOS, the Company models reliability at a system level by ensuring that sufficient resources are available to meet customer load based on the hourly profile of both load and resources. Because the Company is a member of PJM Interconnection, LLC ("PJM"), PLEXOS has the option to fill any deficits in any specific hour with market purchases. PLEXOS

[1] Alternative Plan C uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045, resulting in zero CO_2 emissions from the Company's fleet beginning in 2046.

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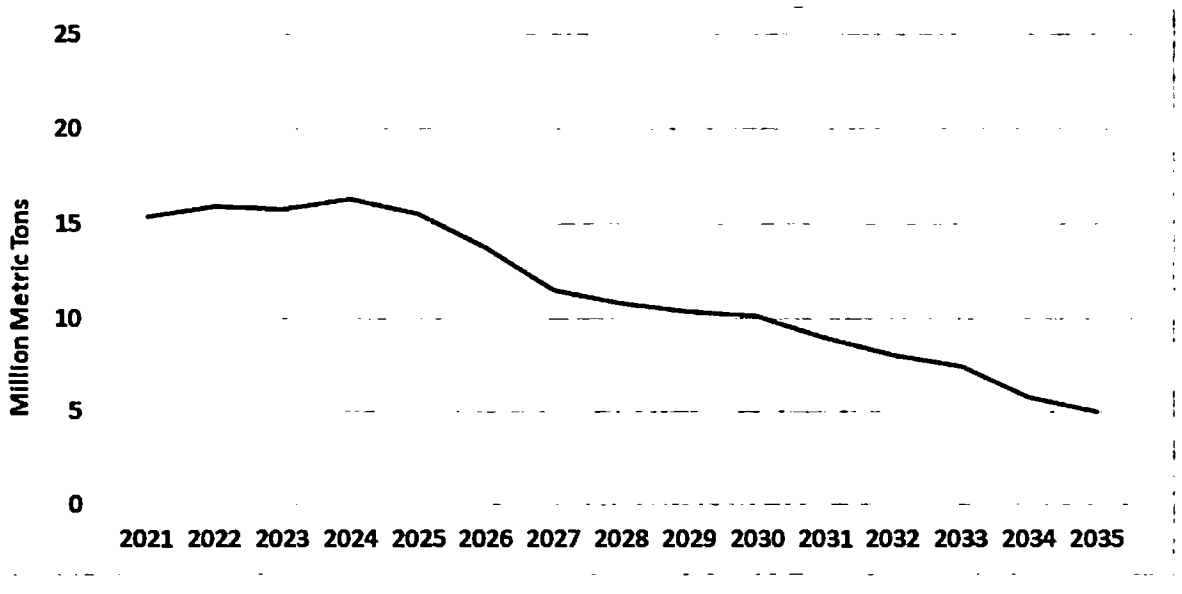
does not currently show any reliability issues through 2035 based on the modeling completed for the 2021 RPS Plan proceeding and the 2021 IRP Update.

Importantly for future planning purposes, however, the Company must take other factors into account to ensure reliability in the long term. For example, if other states pursue the same clean energy future as the Company, resulting in significant volumes of intermittent resources with the same operational profiles as the Company's, the Company may not be able to fill any deficits in specific hours with market purchases. Separate from system level planning, planning at the more granular nodal and feeder level is also needed to ensure reliability, which is completed by the Company's transmission and distribution teams. It is at the nodal level that the system reliability and stability may become a concern based on physical transmission and distribution constraints. The Company continues to actively plan for these potential issues, and will continue to do so as the Company transitions to a cleaner fleet as envisioned by the Commonwealth, the Company, and its customers. See the Company's 2021 IRP Update for a further discussion of the Company's evaluation of seasonal concerns and a status of the Company's long-term transmission reliability analyses.

The RPS Development Plan will support CO_2 reductions in the Commonwealth through the development of a significant amount of CO_2-free generation resources that will displace both market purchases and output from other traditional Company-owned generation units that emit CO_2 as a byproduct of combustion. Figure 2 below shows the projected CO_2 output from the Company's fleet in the Commonwealth through 2035. Figure 2 reflects the RPS Development Plan, as well as the tentative retirements of certain generation units as reflected in Alternative Plan B of the Company's 2021 IRP Update.

Figure 2: Virginia CO_2 Output from Company Fleet, with RPS Development Plan



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To date, the Company has followed the RPS Development Plan in developing CO_2-free generation. The Company has also retired certain generation units consistent with the RPS and IRP plans. The Company further endeavors to minimize customer cost while maintaining reliability through prudent dispatch of dispatchable units. As a member of PJM, the Company offers units for dispatch with accurate cost estimates that include RGGI compliance costs. The PJM market clearing process dispatches the fleet economically. In following the RPS Development Plan and including RGGI costs in dispatch decisions, the Company's RGGI compliance corresponds to its RPS plan filings.

For forward RGGI allowance requirements, the Company projects CO_2 emissions by modeling the system dispatch using assumptions that are consistent with both the 2021 IRP Update (Alternative Plan B) and the 2021 RPS Development Plan. The modeling assumes a capacity factor for existing and future solar resources of 21.2%, which is the three-year average of the Company's solar tracking facilities in Virginia. The RGGI modeling was completed using an updated load forecast and an updated commodity price forecast. The Company uses PLEXOS to model the dispatch of the fleet in the PJM energy market. The dispatch of the fleet produces the system's CO_2 emissions. The PLEXOS dispatch logic includes RGGI compliance costs in the same manner that it includes fuel costs. Therefore, a Company-owned fossil unit operates when the compliance cost of RGGI plus other variable costs like fuel are less than the cost of a market power purchase. In following the RPS Development Plan and including RGGI costs in dispatch decisions, the Company's RGGI compliance cost modeling corresponds to its RPS plan filings.

Attachment 76

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

2220110021

Case Number (if already assigned)	PUR-2021-00281
Case Name (if known)	Petition of Virginia Electric and Power Company for revision of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia
Document Type	EXMO
Document Description Summary	Virginia Electric and Power Company's Motion to Withdraw Application
Total Number of Pages	5
Submission ID	23788
eFiling Date Stamp	1/10/2022 3:08:36PM

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January 10, 2022

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Bernard Logan, Clerk
State Corporation Commission
Document Control Center
Tyler Building, First Floor
1300 East Main Street
Richmond, Virginia 23219

Petition of Virginia Electric and Power Company for revision of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia
Case No. PUR-2021-00281

Dear Mr. Logan:

Enclosed for electronic filing in the above-captioned proceeding, please find *Virginia Electric and Power Company's Motion to Withdraw Application.*

Please do not hesitate to contact me if you have any questions in regard to this filing.

Highest regards,

/s/ Elaine S. Ryan

Elaine S. Ryan

enc.
cc: Arlen Bolstad, Esq.
Frederick D. Ochsenhirt, Esq.
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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY	)	
	)	Case No. PUR-2021-00281
For revision of rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia	)	

VIRGINIA ELECTRIC AND POWER COMPANY'S
MOTION TO WITHDRAW APPLICATION

On December 6, 2021, Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") filed with the State Corporation Commission of Virginia (the "Commission") its annual update filing with respect to its rate adjustment clause ("RAC" or "Rider"), designated Rider RGGI, approved to recover costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide ("CO_2") emissions, a program in which the Company is required to participate pursuant to § 56-585.1 A 5 e ("Subsection A 5 e") of the Code of Virginia ("Va. Code"). Pursuant to Rule 110 of the Commission's Rules of Practice and Procedure,[1] 5 VAC 5-20-110, Dominion Energy Virginia moves to withdraw its update Application without prejudice ("Motion"). In support of its Motion, the Company states as follows:

1. On August 4, 2021, in Case No. PUR-2020-00169 ("2020 Rider RGGI Proceeding"), the Commission issued its Order Approving Rate Adjustment Clause ("Rider RGGI Order"), approving Rider RGGI to be effective for usage on and after September 1, 2021.[2]

[1] 5 VAC 5-20-10 *et seq.* (the "Procedural Rules").
[2] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No PUR-2020-00169, Order Approving Rate Adjustment Clause at 11 (Aug. 4, 2021).

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Subsequently, the Commission suspended the Rider RGGI Order on August 25, 2021 pending consideration of a Petition for Reconsideration or Clarification. On November 17, 2021, by its Order on Reconsideration, the Commission lifted the suspension of the Rider RGGI Order without modification of its initial order. On January 1, 2022, the initial Rider RGGI was implemented, which increased the monthly bill of a residential customer using 1,000 kilowatt-hours per month by approximately $2.39.

2. As set forth in the Company's annual update Application, if approved, the revised Rider RGGI rate would become effective for the rate year commencing September 1, 2022 and would increase the monthly bill of a residential customer using 1,000 kilowatt-hours per month by $1.98. Including the increase associated with the annual update, the total Rider RGGI impact on the typical bill of a residential customer would be $4.37.

3. On December 8, 2021, Governor-elect Glenn Youngkin announced that he intends to withdraw Virginia from RGGI.

4. Due to the uncertainty surrounding the timeline for the Commonwealth's participation in RGGI, as well as the compliance requirements and associated costs for the September 1, 2022 through August 31, 2023 rate year, Dominion Energy Virginia seeks leave to withdraw its Rider RGGI update Application without prejudice. The Company intends to file a new update application to recover its actual and projected RGGI compliance costs informed by these developments at the appropriate time.

5. Good cause exists for the Commission to grant this Motion and allow the Company to withdraw the Application. By granting the Motion, the existing Rider RGGI rate will remain in place to recover past compliance costs already incurred, subject to future true-up, and the Company will be able to better estimate its future compliance costs once the timeline for

the Commonwealth's RGGI participation is more certain. In turn, customers will benefit to the extent they will not bear the burden of increased near-term compliance costs that may not materialize. In the meantime, the Company will continue to meet its compliance obligations under RGGI until the withdrawal is effective.

6. Counsel for the Company has notified Commission Staff of its intention to file this Motion and has been authorized to represent that Staff takes no position on the requested relief.

WHEREFORE, for the reasons set forth in this Motion, the Company respectfully requests that the Commission (i) grant leave for the Company to withdraw the Application without prejudice and deem such Application withdrawn; and (ii) grant such other relief as the Commission deems necessary and appropriate.

Respectfully submitted,

By: */s/ Elaine S. Ryan*
Counsel

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Counsel for Virginia Electric and Power Company

January 10, 2022

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Attachment 77

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, APRIL 1, 2022

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PETITION OF

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUR-2021-00281

For approval of a rate adjustment clause,
designated Rider RGGI, under
§ 56-585.1 A 5 e of the Code of Virginia

ORDER GRANTING MOTION

On December 6, 2021, Virginia Electric and Power Company ("Dominion" or "Company") filed with the State Corporation Commission ("Commission") an annual update of the Company's rate adjustment clause, Rider RGGI ("Petition"), pursuant to § 56-585.1 A 5 e of the Code of Virginia. Through its Petition, Dominion seeks to recover projected and actual costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide emissions.[1]

On January 10, 2022, the Company filed a Motion to Withdraw Application ("Motion"), in which the Company requested to withdraw its Petition, without prejudice. The Company's Motion explains that on August 4, 2021, in Case No. PUR-2020-00169, the Commission approved a rate adjustment clause, designated Rider RGGI, for Dominion to recover costs associated with the Company's purchase of RGGI allowances.[2] Further, the Motion states that on January 1, 2022, the Company implemented its initial Rider RGGI, which increased the

[1] Petition at 1.

[2] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 of the Code of Virginia*, Case No. PUR-2020-00169, Order Approving Rate Adjustment Clause (Aug. 4, 2021).

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monthly bill of a residential customer using 1,000 kilowatt-hours per month by approximately $2.39.

In support of its Motion, the Company states that the December 8, 2021 announcement by then-Governor-elect Glenn Youngkin that he intended to withdraw Virginia from RGGI created uncertainty around the timeline for Virginia's participation in RGGI, as well as the compliance requirements and associated costs for the September 1, 2022 through August 31, 2023 rate year.[3] The Company states that it "intends to file a new update application to recover its actual and projected RGGI compliance costs informed by these developments at the appropriate time."[4] The Company also states that it will continue to meet its RGGI compliance obligations until any withdrawal is effective.[5]

On January 28, 2022, the Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel") filed a response to the Motion ("Response"). Consumer Counsel stated that it did not oppose the Company's request to withdraw its Petition, but stated that "[f]or customers to truly benefit from the voluntary motion to withdraw, Consumer Counsel urges the Company to confirm, and the Commission to order, that customers will not be asked to bear the burden of any additional carrying costs in a future true-up to Rider RGGI as a result of the Company's withdrawal of the [P]etition."[6]

On February 11, 2022, the Company filed a letter reply ("Reply") to Consumer Counsel's Response. The Company states, "To the extent that the Company incurs incremental financing

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[3] Motion at 2.

[4] *Id.*

[5] *Id.* at 3.

[6] Consumer Counsel Response at 2-3.

costs due to the voluntary withdrawal of the Update Application, the Company would agree to waive recovery of such costs from customers in a future true-up of Rider RGGI."[7]

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds that Dominion's Motion should be granted, as set forth below.

Accordingly, IT IS ORDERED THAT:

(1) This matter is docketed and assigned Case No. PUR-2021-00281.

(2) Dominion's Motion to Withdraw Application is granted without prejudice as set forth herein.

(3) On or about July 1, 2022, the Company shall file a status update on Rider RGGI, including the following: the then current under-/over-recovery position; the projected under-/over-recovery position as of December 31, 2022 and October 31, 2023; and shall include any motion to continue the currently-approved Rider RGGI subject to further review and true-up in the update proceeding ordered below.

(4) To the extent that the Company incurs incremental financing costs due to the voluntary withdrawal of the Petition, the Company shall waive recovery of such costs from customers in future true-ups of Rider RGGI.

(5) On or before January 1, 2023, Dominion shall file with the Commission an update to Rider RGGI in accordance with the Commission's Order Approving Rate Adjustment Clause in Case No. PUR-2020-00169 and § 56-585.1 A 5 e of the Code of Virginia.

(6) This matter is continued.

[7] Company Reply at 2.

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A COPY hereof shall be sent electronically by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the Commission.

Attachment 78

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, MARCH 6, 2023

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APPLICATION OF

APPALACHIAN POWER COMPANY

CASE NO. PUR-2022-00139

To increase its fuel factor pursuant to
§ 56-249.6 of the Code of Virginia

ORDER ESTABLISHING 2022-2023 FUEL FACTOR

On September 15, 2022, Appalachian Power Company ("APCo" or "Company") filed with the State Corporation Commission ("Commission") an application ("Application") pursuant to § 56-249.6 of the Code of Virginia ("Code") seeking to increase its fuel factor. The Company proposes to increase the current fuel factor of 2.300 cents per kilowatt-hour ("¢/kWh") to 4.319¢/kWh, effective for service rendered November 1, 2022, through October 31, 2023 ("Fuel Year").[1] To mitigate its requested rate increase, the Company is proposing to recover its deferred fuel balance as of October 31, 2022, over two fuel years.[2] In addition, APCo seeks Commission approval to establish a new rider, designated Rider DFCC. The Company states that it proposes to implement Rider DFCC at a zero rate, to be updated and trued-up in the future, as an alternative to the recovery of the carrying costs on its deferred fuel balance through base rates.[3]

[1] Ex. 2 (Application) at 1, 6.

[2] *Id.* at 1.

[3] *Id.*

The Company's proposed fuel factor consists of both an in-period component and a prior-period component.[4] APCo's proposed in-period component is designed to recover its estimated Virginia jurisdictional fuel expenses during the Fuel Year of approximately $416,140,161, which includes non-incremental costs associated with APCo's Beech Ridge and Grand Ridge wind contracts; the energy components of the Company's other wind and solar resources; a credit for 75% of projected Off-System Sales ("OSS") margins; PJM Interconnection, L.L.C. ("PJM"), Load Serving Entity transmission losses; PJM congestion charges; 100% of incremental transmission line loss margins; and Financial Transmission Right revenues.[5] The Company proposes an in-period factor component of 3.011¢/kWh.[6]

The prior-period component is a true-up component designed to recover from customers over a two-year period an estimated under-recovered deferred fuel balance as of October 31, 2022, of $361,411,867, or $180,705,934 per year.[7] The Company states that it divided the projected deferred fuel cost balance by the projected Virginia jurisdictional energy sales for the Fuel Year to obtain the prior-period under-recovery component of 1.308¢/kWh.[8]

The Company represents that the combined impact of the Company's proposed fuel factor over the Fuel Year is an annual revenue increase of approximately $279 million.[9] APCo

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[4] *Id.* at 3.

[5] Ex. 8 (Castle Direct) at 5.

[6] *Id.*

[7] *Id.* at 6.

[8] *Id.*

[9] Ex. 2 (Application) at 1.

maintains that this proposal would increase the monthly bill of a residential customer using 1,000 kWh of electricity by $20.17.[10]

On October 6, 2022, the Commission entered an Order Establishing 2022-2023 Fuel Factor Proceeding that, among other things, (i) stated "the Company may place its proposed fuel factor into effect on an interim basis for service rendered on and after November 1, 2022;" (ii) scheduled a telephonic hearing for December 13, 2022, to receive the testimony of public witnesses; (iii) scheduled an in-person public evidentiary hearing for December 14, 2022; (iv) directed the Company to provide notice to the public; (v) provided interested persons an opportunity to comment on the Company's Application or to participate as a respondent; and (vi) appointed a Hearing Examiner to conduct all further proceedings in this matter on behalf of the Commission and to file a final report.

The following parties filed notices of participation: Steel Dynamics, Inc. ("SDI"); the Old Dominion Committee for Fair Utility Rates ("Old Dominion Committee"); the VML/VACo APCo Steering Committee ("Steering Committee") and the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel"). No respondent filed testimony.

On November 22, 2022, the Commission's Staff ("Staff") filed its direct testimony. On December 1, 2022, APCo filed rebuttal testimony. On December 13, 2022, the Hearing Examiner appointed by the Commission convened the public witness hearing.[11] On December 14, 2022, the Hearing Examiner convened the evidentiary hearing, as scheduled. APCo, SDI, the Steering Committee, the Old Dominion Committee, Consumer Counsel, and Staff participated at the hearing.

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[10] Ex. 8 (Castle Direct) at 7.

[11] Numerous public comments were also filed opposing APCo's proposed increase to the fuel factor.

On January 18, 2023, the Report of M. Renae Carter, Hearing Examiner ("Report") was issued. The Company, the Steering Committee, the Old Dominion Committee, Consumer Counsel, and Staff subsequently filed comments on the Report.

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds as follows.

Code of Virginia

The Company filed its Application pursuant to Code § 56-249.6, which provides in part as follows:

> A.1. Each electric utility . . . shall submit to the Commission its estimate of fuel costs, including the cost of purchased power, for the 12-month period beginning on the date prescribed by the Commission. Upon investigation of such estimates and hearings in accordance with law, the Commission shall direct each company to place in effect tariff provisions designed to recover the fuel costs determined by the Commission to be appropriate for that period, adjusted for any over-recovery or under-recovery of fuel costs previously incurred.
>
> 2. The Commission shall continuously review fuel costs and if it finds that any utility described in subdivision A 1 is in an over-recovery position by more than five percent, or likely to be so, it may reduce the fuel cost tariffs to correct the over-recovery.
>
> 3. Beginning July 1, 2009, . . ., if the Commission approves any increase in fuel factor charges pursuant to this section that would increase the total rates of the residential class of customers of any such utility by more than 20 percent, the Commission, within six months following the effective date of such increase, shall review fuel costs, and if the Commission finds that the utility is, or is likely to be, in an over-recovery position with respect to fuel costs for the 12-month period for which the increase in fuel factor charges was approved by more than five percent, it may reduce the utility's fuel cost tariffs to correct the over-recovery. . . .
>
> D. In proceedings under subsections A and C:
>
> 1. Energy revenues associated with off-system sales of power shall be credited against fuel factor expenses in an amount equal to the

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> total incremental fuel factor costs incurred in the production and delivery of such sales. In addition, 75 percent of the total annual margins from off-system sales shall be credited against fuel factor expenses; . . . . For purposes of this subsection, "margins from off-system sales" shall mean the total revenues received from off-system sales transactions less the total incremental costs incurred; and
>
> 2. The Commission shall disallow recovery of any fuel costs that it finds without just cause to be the result of failure of the utility to make every reasonable effort to minimize fuel costs or any decision of the utility resulting in unreasonable fuel costs, giving due regard to reliability of service and the need to maintain reliable sources of supply, economical generation mix, generating experience of comparable facilities, and minimization of the total cost of providing service.

Mitigation Proposal

APCo presents a Mitigation Proposal in this case to moderate the impact of the rate increase on customers. Specifically, APCo proposes to recover its significant under-recovery balance of approximately $361.4 million over two years.[12] As described by Consumer Counsel, the Mitigation Proposal "takes what would be a $33 per month bill increase and reduces it to a[n] increase of $20 per month."[13] In consideration of the magnitude of the increase in this case, the Commission approves the Mitigation Proposal which has been in effect on an interim basis.[14]

Off-System Sales Credits

We further note that pursuant to Code § 56-249.6 D I, the Commission is permitted to credit, at most, 75% of the Company's estimated total annual margins from OSS against fuel

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[12] Ex. 8 (Castle Direct) at 4-6 and WKC Schedule 2.

[13] Transcript at 49. *See also* Ex. 10 (Blevins Direct) at 5.

[14] With respect to APCo's request for approval of Rider DFCC to recover carrying costs associated with the deferred fuel balance, we agree with the Hearing Examiner that it should be denied in this limited-issue fuel factor proceeding, without prejudice for the Company to renew its request in a future general rate case such as the Company's next Triennial Review. Report at 24-26, 32.

factor expenses for the benefit of ratepayers. In this proceeding, we have utilized the maximum credit allowed by law – 75% of projected OSS margins – to reduce the fuel rates paid by APCo's Virginia customers.

Fuel Factor

Even with the impacts of the Mitigation Proposal and the OSS credit, we are deeply concerned about the significant rate increase requested in this case, and its impact on customer bills. The impact of the increase is worsened by its introduction during the winter months, which are typically higher usage months, and by other recent APCo rate increases.[15] We are mindful of the numerous public comments and concerns expressed about the impact of such rate increases on APCo's customers and have reviewed this matter carefully. APCo is, however, entitled by law to recover its prudently incurred fuel costs under Code § 56-249.6.[16] The price of fuel that the Company must purchase to generate electricity and that of purchased power have risen significantly. As a result, the Company has materially under-recovered its fuel costs over the last year and its forecasted costs for the coming year have risen markedly. While parties noted

[15] As a result of APCo's appeal of the Commission's decision in APCo's 2020 triennial review and subsequent remand by the Supreme Court of Virginia, APCo's base rates have also increased. In its Order on Remand, the Commission reduced the annual rate increase initially requested by APCo in its remand filing that had been in effect on an interim basis since October 1, 2022. *See Application of Appalachian Power Company, For a 2020 triennial review of its bae rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, Doc. Con. Cen. No. 221230186, Order on Remand (Dec. 21, 2022).

[16] *See, e.g., Commonwealth of Virginia, ex rel. State Corp. Commission, Ex Parte: In the matter of establishing Commission policy regarding rate treatment of purchased power capacity charges by electric utilities and cooperatives*, Case No. PUE-1988-00052, 1988 S.C.C. Ann. Rept. 346, 347 (Nov. 10, 1988) (describing the "fuel factor" as "a statutory adjustment mechanism through which all prudently incurred energy costs are recovered, dollar for dollar"). *See also Application of Kentucky Utilities Company t/a Old Dominion Power Company, To revise its fuel factor pursuant to Virginia Code § 56-249.6*, Case No. PUE-1994-00043, 1995 S.C.C. Ann. Rept. 309, 310, Order Establishing 1994/95 Fuel Factor (Jan. 6, 1995) ("Kentucky Utilities Order") (describing that the "fuel factor mechanism . . . gives the Company dollar for dollar recovery for allowable fuel expenses"); *Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6*, Case No. PUE-2008-00039, 2008 S.C.C. Ann. Rept. 533, 534, Order Establishing Fuel Factor (June 27, 2008) ("the fuel factor permits dollar for dollar recovery of prudently incurred fuel costs") (emphasis in original).

concerns with the amount of the proposed increase and its impact on customers, no party or Staff raised issues with the Company's forecasts.[17]

In consideration of this matter, we adopt the findings set forth in the Hearing Examiner's Report, except as modified herein, and find that a revised total fuel factor of 4.319¢/kWh, consisting of an in-period period factor of 3.011¢/kWh and a prior period factor of 1.308¢/kWh is approved for usage on and after November 1, 2022. We note that this is the same total fuel factor that the Company placed into effect on an interim basis for usage on and after November 1, 2022, and therefore, will not result in an additional increase at this time.

In granting this approval, the Commission notes its awareness of the ongoing rise in gas prices, inflation, and other economic pressures that are impacting all utility customers. We are sensitive to the effects of rate increases, especially in times such as these. The Commission, however, must follow the laws applicable to this case, as well as the findings of fact supported by the evidence in the record. This is what we have done herein.

Fuel Audit & Coal Procurement Practices

As explained in prior cases, approval of the fuel factor herein does not represent ultimate approval of the Company's fuel expenses. This approval is based in part upon the Company's estimate of future fuel expenses yet to be incurred. An audit and investigation of the Company's actual booked fuel expenses and OSS margins, among other things, will be conducted by the Staff after the close of the fuel year. The Commission subsequently determines what are, in fact, prudent and, therefore, allowable fuel expenses, as well as the Company's recovery position at the end of the audit period. The Commission has previously described this review as follows:

[17] Report at 22.

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> Should the Commission find in its Final Audit Order (1) that any component of the Company's actual fuel expenses or credits has been inappropriately included or excluded, or (2) that the Company has failed to make every reasonable effort to minimize fuel cost or has made decisions resulting in unreasonable fuel cost, the Company's recovery position will be adjusted. This adjustment will be reflected in the recovery position of the Company's next fuel factor. We reiterate that no finding in this order is final, as this matter is continued generally, pending Staff's audit of actual fuel expenses.[18]

Accordingly, no finding in this Order Establishing Fuel Factor is final, as this matter is continued generally, pending audit and investigation of the Company's actual fuel expenses.

The parties and Staff reference an investigation by the West Virginia Public Service Commission into APCo's coal fuel procurement activities related to the Company's Amos and Mountaineer plants which are used in part to serve APCo's Virginia customers. Every party except the Company asked the Commission to undertake a similar investigation, or at a minimum, monitor the proceeding in West Virginia and undertake an investigation if the West Virginia Public Service Commission finds that improper action on APCo's part has driven up the cost of fuel.[19]

We find that Staff should forthwith commence its fuel audit of the January 1, 2019 to December 31, 2022 period.[20] In so finding, we stress that no party to this case, nor Staff, has asserted or concluded that APCo has acted imprudently in its procurement of coal. Rather, we agree with the Hearing Examiner that a review of the reasonableness of APCo's coal

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[18] Kentucky Utilities Order, 1995 S.C.C. Ann. Rept. at 311.

[19] *See, e.g.,* Report at 27 (citing statements by counsel for SDI, the Steering Committee, the Old Dominion Committee and Consumer Counsel).

[20] In its comments on the Hearing Examiner's Report, Staff indicated that it is capable of conducting such an audit and including the results of the audit in APCo's 2023 Fuel Factor proceeding. Staff Comments on the Hearing Examiner's Report at 1.

procurement practices is appropriate under the circumstances and is consistent with the law and with Commission practice.[21] Specifically, such audit should include a focus on whether APCo has made "every reasonable effort to minimize fuel costs or [has made] any decision[s] . . . resulting in unreasonable fuel costs" consistent with the requirements of Code § 56-249.6 D 2.

As part of its fuel audit, Staff shall investigate and report on, at a minimum, the following with respect to APCo's coal procurement activities, as recommended by the Hearing Examiner:[22]

- Whether APCo complied with its Regulated Fuel Procurement Policy and Procedures Manual;
- The timing and adequacy of APCo's response to market turmoil in mid-2021;
- APCo's actions to obtain performance by contractors with whom APCo had coal supply agreements;
- APCo's ability to maintain coal inventories at minimum target levels; and
- If APCo had the ability to maintain the minimum target levels of coal inventory, what additional generation would have been available to APCo.

Staff shall include the results of such fuel audit in its prefiled testimony in APCo's next fuel factor proceeding.[23]

Further in this regard, for informational purposes, we direct APCo to file in this docket copies of any orders issued by the West Virginia Public Service Commission concerning its investigation of APCo's coal procurement practices[24] and address the status, including any decisions of the West Virginia Public Service Commission, in APCo's next fuel factor

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[21] *See, e.g.*, Report at 29-30.

[22] *Id.* at 30.

[23] In addition, Staff shall file a copy of such audit report in the docket(s) in which the fuel factor for the applicable audit period was originally approved.

[24] Such proceedings include Case Nos. 21-0339-E-ENEC, 22-0393-E-ENEC and any related dockets.

application. Staff should also monitor these proceedings and report on developments when Staff files testimony in APCo's next fuel factor proceeding.

Information on Payment Assistance

The Commission reiterates its concern regarding the impacts of this significant rate increase on customers. We agree with the Hearing Examiner that APCo should take additional steps to advise its customers of opportunities for payment assistance.[25] We direct APCo, within 60 days from the date of this Order, to remind customers how they may contact the Company for bill assistance and to set up budget billing for their accounts. Such reminder should be provided through social media as well as at least one non-social media outlet such as bill stuffers or a newsletter to reach customers that prefer not to use social media or do not have internet access. APCo shall confirm such reminder has been completed through a filing with the Commission in this docket no later than 70 days following entry of this Order.

Staff to Monitor Deferred Fuel Balance

Finally, we direct the Staff to monitor the Company's fuel cost recovery on a monthly basis. If the Staff finds evidence of a change in the recovery balance that permits the Commission, pursuant to Code § 56-249.6 A 2, to adjust the fuel factor downward during the current period, we will review the matter to determine whether fuel rates should be decreased.

Accordingly, IT IS ORDERED THAT:

(1) The findings and recommendations contained in the Hearing Examiner's Report are adopted except as modified herein.

(2) The Company's fuel factor shall be 4.319¢ per kWh effective for service rendered on and after November 1, 2022.

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[25] Report at 32.

(3) The Company shall comply with the directives set forth in this Order.

(4) Staff shall forthwith commence its audit of the January 1, 2019 to December 31, 2022 period as further described herein.

(5) Staff shall monitor the Company's fuel cost recovery on a monthly basis and shall notify the Commission if there is evidence of a change in the recovery balance that permits the Commission, pursuant to Code § 56-249.6 A 2, to reduce the fuel factor during the current period.

(6) This matter is continued.

Commissioner Patricia L. West participated in this matter.

A COPY hereof shall be sent electronically by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the Commission.

Attachment 79

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, NOVEMBER 21, 2022

SCC - CLERK'S OFFICE
DOCUMENT CONTROL CENTER

2022 NOV 21 A 10:31

PETITION OF

APPALACHIAN POWER COMPANY

For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia

CASE NO. PUR-2022-00001

FINAL ORDER

On March 18, 2022, pursuant to Code § 56-585.1 A 5 e, Appalachian Power Company ("APCo") filed with the State Corporation Commission ("Commission") a petition ("Petition") for approval to recover costs through its existing rate adjustment clause (the "E-RAC") related to capital investments and operations and maintenance compliance expenses that, according to APCo, are necessary to comply with state and federal environmental regulations.[1]

On April 21, 2022, the Commission issued an Order for Notice and Hearing that, among other things: docketed the Petition; required service and public notice thereof; granted certain waivers requested by APCo; directed the Commission's Staff ("Staff") to investigate the Petition and to file testimony containing the results of Staff's investigation; provided interested persons opportunities to participate in this proceeding; scheduled an evidentiary hearing; and appointed a Hearing Examiner to conduct all further proceedings on behalf of the Commission.

[1] APCo completed its filing on March 31, 2022, by submitting its Schedule 3 - Capital Structure and Cost of Capital Statement. The Commission's final order in this matter is due within eight (8) months from that date, or by November 30, 2022. Code § 56-585.1 A 7.

The following filed notices of participation: Sierra Club; West Virginia Coal Association, Inc.; Appalachian Voices; and the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel").

On September 21, 2022, the evidentiary hearing was convened before Commission Hearing Examiner D. Mathias Roussy, Jr., in the Commission's courtroom. The Hearing Examiner issued his Report in this matter on October 18, 2022 ("Report"). On November 1, 2022, comments on the Report were filed by: APCo; Sierra Club; Appalachian Voices; Consumer Counsel; and Staff.

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds as follows.[2]

After analyzing the law and weighing the evidence – and providing a thorough and detailed analysis thereof – the Hearing Examiner made the following recommendations:[3]

> Accordingly, **I RECOMMEND** that the Commission enter an order that:
>
> (1) ***APPROVES*** an approximately $21 million [Effluent Limitation Guidelines ("ELG")] investment in Mountaineer, and an approximately $63.5 million ELG investment in Amos, subject to the condition that APCo not seek from Virginia any costs of uneconomic regulatory dispatch (if required by the [West Virginia Public Service Commission]) and the Commission's ability to implement this commitment through rate ring-fencing;
>
> (2) ***DENIES***, without prejudice, the proposed recovery of Amos dry sorbent injection reconfiguration costs;
>
> (3) ***DENIES***, without prejudice, the proposed recovery of approximately $95,000 of 2021 [Regional Greenhouse Gas Initiative] costs;

[2] The Commission has fully considered the evidence and arguments in the record. *See also Board of Supervisors of Loudoun County v. State Corp. Comm'n*, 292 Va. 444, 454 n.10 (2016) ("We note that even in the absence of this representation by the Commission, pursuant to our governing standard of review, the Commission's decision comes to us with a presumption that it considered all of the evidence of record.") (citation omitted).

[3] Report at 82 (emphases in original).

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(4) ***APPROVES*** a $32,890,000 revenue requirement to revise the E-RAC rates for service to be rendered from December 1, 2022, to November 30, 2023;

(5) ***DIRECTS*** APCo, each time it self-schedules Clinch River, to record the hours of each day that Clinch River self-schedules, the associated megawatts that are self-scheduled, and the reason for each self-scheduling;

(6) ***CLARIFIES*** that the E-RAC rates should be incorporated into the balancing charge associated with the non-renewable generation rate adjustment clauses of APCo's Rider WWS;

(7) ***DIRECTS*** APCo to incorporate a depreciation rate analysis of its E-RAC investment in its next depreciation study, including net salvage considerations and any excess/deficient depreciation accruals on such assets through the date of the study; and

(8) ***DISMISSES*** this case.

Upon consideration of the record in this matter, the Commission concludes that the Hearing Examiner's findings and recommendations are supported by law and the evidence, are imbued with a rational basis, and are adopted herein.[4]

Accordingly, IT IS ORDERED THAT:

(1) The Commission adopts the Hearing Examiner's findings and recommendations as set forth herein.

(2) The Hearing Examiner's recommendations, set forth above, are hereby ordered.

(3) The Company forthwith shall file a revised E-RAC and supporting workpapers with the Clerk of the Commission and shall submit the same to the Commission's Divisions of Public Utility Regulation and Utility Accounting and Finance, as is necessary to comply with the directives set forth in this Order. The Clerk of the Commission shall retain such filings for

[4] *See, e.g.*, Report at 48-82.

public inspection in person and on the Commission's website: scc.virginia.gov/pages/Case-Information.

(4) This matter is dismissed.

A COPY hereof shall be sent electronically by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the Commission.

Attachment 80

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

220322030361

Case Number (if already assigned)	PUR-2022-00001
Case Name (if known)	Petition of Appalachian Power Company for approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia
Document Type	EXPE
Document Description Summary	Petition of Appalachian Power Company-E-RAC
Total Number of Pages	99
Submission ID	24382
eFiling Date Stamp	3/18/2022 4:43:37PM

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

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March 18, 2022

By Electronic Filing **PUBLIC VERSION**

Hon. Bernard J. Logan, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street, First Floor
Richmond, Virginia 23219

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Re: Petition of Appalachian Power Company for approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia Case No. PUR-2022-00001

Dear Mr. Logan:

Please find attached for filing the Petition of Appalachian Power Company for approval of a rate adjustment clause under § 56-585.1 A 5 e to recover costs to comply with state and federal environmental regulations. Please note that the Company is requesting in the Petition a waiver of the Commission's Rate Case Rules that would permit it to file one hard copy of certain confidential and/or voluminous materials, as well as electronic copies of these documents on three compact disks, which are being filed simultaneously by hand with the Commission under separate cover. The Company has also made this information available to Staff.

The Company is also simultaneously filing a Motion for Protective Ruling.

Sincerely,

Noelle J. Coates

Enclosures
cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF

APPALACHIAN POWER COMPANY

Case No. PUR-2022-00001

for approval of a rate adjustment clause,
the E-RAC, for costs to comply with state
and federal environmental regulations
pursuant to § 56-585.1 A 5 e of the Code of Virginia

PETITION

March 18, 2022

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF

APPALACHIAN POWER COMPANY Case No. PUR-2022-00001

for approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF

APPALACHIAN POWER COMPANY

for approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to §§ 56-585.1 A 5 e of the Code of Virginia

Case No. PUR-2022-00001

PETITION AND REQUESTS FOR WAIVER

Appalachian Power Company ("Appalachian" or the "Company"), by counsel, pursuant to Section 56-585.1 A 5 (e) of the Code of Virginia (the "E-RAC Statute") respectfully petitions the State Corporation Commission (the "Commission") for approval to recover costs through its existing rate adjustment clause (the "E-RAC"), related to capital investments and operations and maintenance ("O&M") compliance expenses that are necessary to comply with state and federal environmental regulations. In support of this Petition, the Company respectfully states as follows.

1. Overview and Background

Appalachian is a Virginia public service corporation serving approximately 524,000 customers in Virginia and maintaining an office at 1051 East Cary Street, Suite 1100, Richmond, Virginia 23219. The Company is an incumbent electric utility as defined in Section 56-576 of the Virginia Electric Utility Regulation Act. The contact information for Appalachian's attorneys is stated at the end of the Petition.

With this Petition, the Company is requesting the Commission's approval to recover on a timely basis through its existing E-RAC, which the Commission initially approved in 2021[1]

[1] Order Granting Rate Adjustment Clause, *Petition of Appalachian Power Company For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal*

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pursuant to the E-RAC Statute, actual and projected costs to comply with state and federal environmental laws and regulations applicable to generation facilities used to serve the Company's load obligations. Specifically, the Company seeks to recover a revenue requirement $33.6 million during the Rate Year of December 1, 2022 through November 30, 2023 through the E-RAC. This amount, detailed by Company witness Castle, is comprised of the following:

- Actual and projected capital investment incurred to comply with the EPA's Coal Combustion Residuals Rule ("CCR Rule") at the Company's Amos and Mountaineer Plants (the "Plants"), the recovery of which the Commission approved in the 2021 E-RAC Order;
- Actual and projected capital investment incurred to comply with the EPA's Steam Electric Effluent Limitation Guidelines ("ELG Rule") at the Plants (the "ELG Projects"), the recovery of which the Commission denied without prejudice in the 2021 Order (the "ELG Project Costs"), including those incurred up to August 2021 (the "Prerequisite ELG Project Costs");
- New capital investments related to dissolved oxygen levels at the hydroelectric generating units at the Company's Claytor Hydro Project ("Claytor") and the dry sorbent injection system at Amos;
- Actual and projected costs to comply with the regulation that established Virginia as a member of the Regional Greenhouse Gas Initiative ("RGGI") associated with the dispatch of the Company's gas-fired Clinch River Plant, which is located in Carbo, Virginia; and
- Actual and projected Operations and Maintenance ("O&M") compliance costs incurred in complying with State Solid Waste regulation, the National Pollution Discharge Elimination System, and provisions of the Clean Water Act at Appalachian's generation units (the "O&M Compliance Expenses"), the recovery of which the Commission approved in the 2021 E-RAC Order.

2. Procedural History

The Company filed for approval in December 2020 to recover the O&M Compliance Expenses, and costs associated with compliance with the CCR Rule and the ELG Rule at the Plants. In the 2021 E-RAC Order, the Commission approved recovery of the O&M Compliance Expenses and the costs to comply with the CCR Rule, which enabled the Plants to continue to

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environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia, Case No. PUR-2020-00258, Doc. Con. Cen. No. 210830184 (August 23, 2021) ("2021 E-RAC Order").

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operate for the benefit of Virginia customers. But the Commission denied the costs to comply with the ELG Rule, which is necessary for the Plants to operate past 2028, concluding that Appalachian had "not met its burden of proving the reasonableness and prudence of the proposed ELG investment costs," including the Prerequisite ELG Project Costs.[2] The Commission held that it was "critically important to analyze the overall impact of this investment on both customer rates and reliability," and concluded that Appalachian should be permitted to provide additional analyses and evidence to support the ELG investment, "should APCo conclude circumstances so warrant."

On December 23, 2020, Appalachian also filed a petition with the Public Service Commission of West Virginia ("WVPSC") seeking certificates of convenience and necessity authorizing both the CCR and ELG projects at the Plants, as well as a cost recovery mechanism.[3] The WVPSC approved the requests on August 4, 2021, concluding that the CCR and ELG Projects at the Plants were "prudent, cost effective, and in the best interest of the current and future utility customers."[4] On October 12, 2021, the WVPSC issued another order that confirmed its earlier decision, stating that, due to the 2021 E-RAC Order, "after 2028 West Virginia customers will receive the full capacity and energy capabilities of" the Plants."[5] That

[2] 2021 E-RAC Order at 12.

[3] The petition before the WV PSC also concerned the Mitchell Plant, which does not serve customers in Virginia and thus is not at issue in proceedings before this Commission.

[4] Commission Order at 16, *Application of Appalachian Power Company and Wheeling Power Company, public utilities, for a certificate of public convenience and necessity for the internal modifications at coal fired generating plants necessary to comply with federal environmental regulations and surcharge*, Case No. 20-1040-E-CN (WVPSC, Aug. 4, 2021).

[5] Commission Order at 7, *Application of Appalachian Power Company and Wheeling Power Company, public utilities, for a certificate of public convenience and necessity for the internal modifications at coal fired generating plants necessary to comply with federal environmental regulations and surcharge*, Case No. 20-1040-E-CN (WVPSC, Oct. 12, 2021).

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is: "Given [the 2021 E-RAC Order], Virginia...jurisdictional customers should receive no capacity or energy from the Plants after 2028."[6]

As the Plants will continue to operate past 2028, no matter how the Commission rules on this Petition, the Company concluded that circumstances warrant re-filing its request to recover the costs of the ELG Projects in accordance with the 2021 E-RAC Order. With this Petition, the Company provides a more robust record of the benefits realized, including the impacts of the investments on customer rates and reliability, by keeping the Plants available to serve its Virginia customers.

3. WITNESSES IN SUPPORT OF THE PETITION

The following witnesses testify in support of the Petition:

- **Christian T. Beam**, President and Chief Operating Officer at Appalachian. Mr. Beam describes the outcome of the CCR/ELG proceeding before the WVPSC and how it led Appalachian to make another request for ELG investment cost recovery from APCo's Virginia customers; explains the practical impact of the WVPSC's Order on Virginia customers; and sets out the options available to the Commission and the potential costs that Virginia customers would face if the Commission again denies ELG investment cost recovery from Appalachian's Virginia customers.

- **James F. Martin**, Director of Resource Planning Strategy for American Electric Power Service Corporation ("AEPSC"). Mr. Martin sponsors an economic analysis that he performed for and provided to the Company's management that compares the forecasted Virginia jurisdictional cost of service effects of a scenario in which the costs, energy, and capacity of the Plants continue to benefit Virginia customers after 2028 to scenarios in which they do not. Mr. Martin also explains the importance of the Company's PJM capacity requirement, and how PJM computes capacity credit for the primary alternative resource options that could replace the Plants. He discusses the impact of the Virginia Clean Economy Act ("VCEA") on the evaluation of the merits of the ELG investment, and on the value of continued operation of the Plants in general. Mr. Martin also discusses RGGI compliance at Clinch River.

- **Brian D. Sherrick**, Managing Director of Projects for AEPSC. Mr. Sherrick describes the Plants, and the planning for and status of the CCR/ELG projects. He discusses the costs the CCR/ELG projects, including the reasonableness and prudence of the previously incurred ELG costs. Mr. Sherrick also describes the DSI project at Amos and its cost.

[6] *Id.* at 8.

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- **Robert A. Gallimore,** Hydroelectric Asset Manager, AEPSC. Mr. Gallimore describes Claytor and the DO project; the costs and current status of the project; and the alternatives that were considered.
- **Gary O. Spitznogle**, Vice President of Environmental Services at AEPSC. Mr. Spitznogle describes the applicable environmental regulations that drive the need and timing for the environmental improvement projects at Appalachian's generation units, and describes the requirements for compliance that result from the WVPSC's orders related to the CCR/ELG projects at the Plants. He outlines the permitting required to install the environmental controls that are the subject of this Petition, and supports the identification of activities undertaken that are required to comply with state and federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the O&M Compliance Expenses as well as new capital investments related to DO levels at Claytor and the DSI system at Amos. Mr. Spitznogle describes RGGI, and how Virginia's participation in RGGI caused the Company to incur costs.
- **Tyler H. Ross,** Director of Regulatory Accounting Services for AEPSC. Mr. Ross reviews the E-RAC over-/under-recovery accounting recorded on the Company's books through December 31, 2021, and provides details of accounting performed to date and proposed recovery and accounting regarding the RGGI costs incurred at Clinch. Mr. Ross provides an overview of costs incurred and forecasted costs related to the ELG Projects at the Plants, to the DSI project at Amos, and to the DO project at Claytor. Finally, Mr. Ross describes the required accounting for costs incurred related to the CCR, ELG, DSI and DO projects.
- **William K. Castle**, Director, Regulatory Services – VA/TN for Appalachian. Mr. Castle provides an overview of the Company's last E-RAC filing. He supports the Virginia jurisdictional revenue requirement of $33.7 million for the E-RAC, and explains the four components of that revenue requirement to be recovered through the Rate Year of December 1, 2022 through November 30, 2023. Mr. Castle explains the allocation factors used to allocate the E-RAC revenue requirement to the Virginia retail jurisdiction and the calculation of the proposed E-RAC rates designed to recover the revenue requirement. Finally, he sponsors the proposed E-RAC tariff sheets.

4. The Requests for Approval in this Petition

The E-RAC Statute allows utilities to request the Commission's approval to recover, through a rate adjustment clause, projected and actual costs to "comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations." Such a petition should be approved if the Commission "finds that such costs are necessary to comply with such environmental laws or regulations." Va. Code § 56-585.1 A 5 (e).

A. The Environmental Regulations

The costs that Appalachian requests for recovery in this Petition were or will be incurred to comply with the following state or federal environmental laws or regulations, as detailed in Mr. Spitznogle's testimony.

i. The CCR Rule

In 2015, the United States Environmental Protection Agency ("EPA") published a final rule to regulate the disposal of coal combustion residuals, the CCR Rule, which includes fly ash, bottom ash, and gypsum that may be generated at coal-fired electric generating units. The CCR Rule applies to new and existing CCR landfills and CCR surface impoundments (ponds) at operating coal-based electric generating facilities. Recent revisions to the CCR Rule require that unlined CCR storage ponds must cease operations and initiate closure by April 11, 2021. The EPA can extend the compliance date for the Plants to as late as October 15, 2023.[7]

ii. The ELG Rule

The Steam Electric Effluent Limitations Guidelines, the ELG Rule, establishes discharge limits on flue gas desulfurization wastewater, fly ash and bottom ash transport water, and flue gas mercury control wastewater. Recent revisions to the ELG Rule establish discharge limits that must be achieved as soon as possible between October 13, 2021 and December 31, 2025 based on the renewal of the existing wastewater discharge permit for the facility.

iii. Dissolved Oxygen Requirements

The dissolved oxygen requirements at Claytor were issued by the Federal Energy Regulatory Commission ("FERC") and are designed to improve low dissolved oxygen conditions in accordance with Virginia Department of Water Quality ("DEQ") requirements.

[7] The Company's request for an extension is still pending, as Mr. Spitznogle explains.

2023-00159

iv. Cross-State Air Pollution Rule

Appalachian installed the DSI system at Amos to mitigate emissions of SO_3 that result from the operation of the Selective Catalytic Reduction ("SCR") and Flue Gas Desulfurization ("FGD") systems in tandem. Appalachian installed the SCR and FGD systems to comply with what is now the Cross-State Air Pollution Rule, as well as a consent decree with the EPA and others.

v. RGGI

In 2020, the Virginia General Assembly amended the Clean Energy and Community Flood and Preparedness Act to direct the Virginia DEQ to adopt regulations to establish a cap-and-trade program for carbon dioxide emissions to comply with the RGGI Model Rule. Those regulations became effective in July 2020, and are applicable to Clinch River, which is the Company's only fossil-fuel fired generation facility in the Commonwealth.

vi. Other Applicable Environmental Regulations

The other applicable environmental regulations for which the O&M Compliance Expenses were incurred are provided in APCo Exhibit No. ____ (GOS), Schedule 1, sponsored by Company witness Spitznogle.

5. The Requested Revenue Requirement and Rate Impact

The Company requests the Commission's approval to recover a total revenue requirement of $33.6 million during the Rate Year. Specifically, the Company seeks to recover:

- A Forecast Rate Year Component of $29.6 million
- A Forecast AFUDC Revenue Component of $4.3 million
- A True-up Revenue Component of ($0.5 million)
- An Actual Revenue Component of $0.2 million

Mr. Castle describes these components in greater detail in his testimony.

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If approved, the revenue requirement would be an increase of $6.2 million over that approved in the 2021 E-RAC Order. Appalachian estimates that implementing this revenue requirement would increase a residential customer's monthly bill, based on 1,000 kWh usage per month, by $0.80, or 0.6% when compared to rates effective December 1, 2021.

As described by Mr. Castle, the Company seeks to recover the revenue requirement by allocating costs to the Virginia jurisdiction consistent with the methodology proposed by the Company and adopted by the Commission in the 2021 E-RAC proceeding.

6. Compliance with the 2021 E-RAC Order

The Commission and Senior Hearing Examiner Berkebile concluded that the record in the 2021 E-RAC proceeding was deficient. In this Petition, the Company has attempted to address these deficiencies as follows, with some adjustments given that the Plants will still operate past 2028 regardless of the outcome of this Petition:

- The overall impact of the ELG investment on customer rates is discussed by Mr. Castle, and Mr. Martin's analysis focuses on the impact on Virginia customer rates, should ELG cost recovery be denied.
- The reasonableness and prudence of the Prerequisite ELG Project Costs is discussed by Company witnesses Spitznogle and Sherrick.
- The reasonableness and prudence of the ELG costs from an economic or resource adequacy perspective is discussed by Mr. Martin.
- The impacts of the VCEA on the ELG investment are discussed by Mr. Beam and Mr. Martin.
- The potential stranded costs are discussed by Mr. Ross.
- Mr. Ross sponsors the depreciation costs that would be the responsibility of Appalachian's Virginia customers if they no longer benefitted from the Plants after 2028.
- A detailed analysis of potential transmission cost impacts associated with retiring the Plants in 2028 is not provided because, as Mr. Martin recounts, the Plants will not retire in 2028 and thus there will be no resultant transmission cost impacts. Similarly, the Company did not assess the overall impact of the ELG investment on reliability, because the Plants will continue to operate after 2028.

2021-00236

7. The Reasonableness and Prudence of the Requests

A. The CCR/ELG Projects

The testimony supporting this Petition demonstrates that the CCR and ELG Projects are the most reasonable and prudent means of meeting Appalachian's obligations to its Virginia customers.

As detailed in the 2021 E-RAC proceeding, the Company explored multiple alternative compliance strategies and ultimately determined that the Projects, which are described in detail in the testimony and schedules of Mr. Sherrick, were the most reasonable and prudent means of compliance with the CCR and ELG Rules.

As noted above, in the 2021 E-RAC Order, the Commission found that the Company had not met its burden to demonstrate the reasonableness and prudence of the investment in the ELG Projects.[8] Accordingly, in order to demonstrate that recovery of the costs related to the ELG Projects from Virginia customers is reasonable and prudent, Company witness Martin performed an analysis that compared the investment in the ELG Projects at the Plants to scenarios that assumed that the Plants were no longer available to Virginia customers. That analysis demonstrates clearly that continued operation of the Plants, even if they do not run at all, is less expensive and much less risky for Virginia customers than retiring the Plants early and replacing them. If the roughly 2,100 MW (nameplate) Virginia jurisdictional share of capacity of the Plants is available to Virginia customers, the Company will avoid incurring substantial cost, which will be passed along to the Virginia ratepayers, to obtain some other source of capacity to cover the Virginia portion of the PJM capacity obligation.

[8] 2021 E-RAC Order at 12.

As Mr. Martin and Mr. Beam testify:

- The relatively small $98 million jurisdictional share of the ELG investments and continued use of the Plants will be much less expensive than replacing them with billions of dollars of new resources;
- Replacement capacity costing between $3-4 billion would increase customers' rates by an incremental 17-21% in 2029 over what customers paid in 2021;
- In total, between 2029 and 2040, the net cost of service for the replacement resources would be between $2.8 billion and $3.4 billion, compared to the incremental cost of keeping the Plants operating of $1.0 billion; and
- The above is true even if the Plants do not generate a single MWh of electricity after 2029, due to their capacity value.

Mr. Martin also prepared an estimate of how much wind and solar would be needed to replace the Virginia jurisdictional share of the Plants' PJM-accredited capacity. By his estimation, it would take 8,800 MW (nameplate) to be placed in service by 2028 in order to match the capacity that the Plants provide for the benefit of Virginia customers. This is 17.7 times the amount of wind and solar that is required to be added by the VCEA. This massive investment would be costly (as much as $15 billion) and difficult, given the challenges of siting and constructing renewable facilities. Mr. Martin estimates that the cost of such a portfolio would be four times the incremental cost of keeping the Plants available to Virginia customers through 2040.

In addition to imposing great expense and uncertainty on Virginia customers, the Commission's denial of cost recovery for the ELG investment from Virginia customers would create a practical and regulatory conundrum, as Mr. Beam explains. Appalachian would have to find a way to replace the energy and capacity that the Plants currently provide to its Virginia customers, and, as the Plants will continue to operate past 2028, an equitable – but complicated - arrangement could be made in which Virginia customers compensate West Virginia customers for the capacity provided by the Plants. As Mr. Martin's analysis demonstrates, the other options for replacement capacity are significantly more expensive and uncertain. For replacement

2022-00328-P

energy to serve its Virginia customers, Appalachian could purchase replacement energy from PJM, which would expose them to more energy market volatility.

Importantly, as energy on the PJM market is overwhelmingly generated from fossil fuels, eschewing the energy generated from the Plants in favor of market energy would not materially advance any clean energy goals. Similarly, as the Plants will continue to provide capacity and energy to Appalachian's West Virginia customers no matter how the Commission rules, denying ELG investment cost recovery from Virginia customers will not result in closing the Plants in 2028.

This Petition is thus supported by compelling evidence that the ELG investments are reasonable and prudent, and that the Commission should approve cost recovery from Appalachian's Virginia customers for the ELG investments, so that customers can continue to benefit from the Plants after 2028.

B. Prerequisite ELG Project Costs

Through August 2021, Appalachian incurred approximately $19.5 million and $12.6 million for the ELG Projects at Amos and Mountaineer, respectively. The costs related to project initiation, technology feasibility studies, evaluation of risk balanced technical options, conceptual engineering, permitting, and site investigations (surveying, verifying as-built conditions, and geotechnical investigations), as Company witness Sherrick describes. Appalachian could not avoid incurring these costs before seeking regulatory approval as they were necessary to establish the projects' scope, schedule, and cost estimate, all of which inform the regulatory proceedings, as well as necessary to meet environmental compliance deadlines. No physical construction related to ELG project activities began at the Plants before August 2021. The costs were therefore reasonable, prudent, and necessary.

C. The DO Project at Claytor

The DO Project at Claytor, which is discussed by Company witnesses Spitznogle and Gallimore, is designed to increase dissolved oxygen in the plant's tailwaters, which will improve the water quality, thus reducing impacts to aquatic organisms and angling opportunities. The DO Project involves the installation of auto-venting turbines ("AVT") in two generating units. AVT is the preferred technology for downstream DO improvement by providing the greatest percentage of increased DO concentration. Appalachian expects that the installation of AVT at Claytor will produce an increase in megawatt output of at least 10% per unit. Accordingly, this project is the best, and most reasonable, solution at the plant.

D. The DSI Modification at Amos

As Mr. Spitznogle describes, Amos is equipped with SCR and FGD systems to reduce NO_x and SO_2. When both are operated together, a small portion of the SO_2 is converted to SO_3, which is an acid gas that can cause visible emissions from the stack. The DSI system mitigates those emissions. When it was first installed, the system used trona, but the Company is modifying the system to use hydrated lime, which will reduce O&M costs. Mr. Sherrick explains that the project will reduce corrosion and improve heat rate and the Equivalent Unplanned Outage Rate. It will also help with the long-term protection of the SCR catalyst, air heaters, and precipitators, all of which demonstrate the reasonableness and prudence of the investment.

E. RGGI Costs Related to Clinch River

Clinch River, a gas-fired plant, is located in Virginia, and thus subject to RGGI compliance costs, which have been deferred to date. Clinch River only dispatches when it is economic to do so compared to the other resources that have been offered into PJM. The total price offered into PJM's energy market for Clinch River includes the cost of RGGI allowances. Thus, any RGGI-related costs are offset by energy revenues, which flow back to customers as

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reductions in fuel expense. Appalachian thus incurs the RGGI costs in order to comply with the law, but manages them in a reasonable and prudent way.

8. Compliance with Rate Case Rules and Requests for Waiver

First, Rate Case Rule 60 requires that applications requiring an overall cost of capital include Schedules 3, 4, 5, and 8. Filing Schedules 3 through 5 and 8, sponsored by Mr. Castle, provide this information. The required components of Schedule 46, established by the Rate Case Rules, are sponsored by Company witnesses and are attached to and/or incorporated into their testimonies, as set out in the Index of Schedule 46 Requirements, which is attached to this Petition as Attachment 1.

Second, the Company provided the Commission notice of its intent to file this Petition, pursuant to Rule 10 A, on October 21, 2021.

Third, the Company requests, pursuant to Rule 20VAC5-204-10.E, that the Commission grant a limited waiver, for good cause shown, of the requirement to file the documents that comprise Schedule 46 in hard copy. Due to the size of some of these documents, as well as the current remote conditions under which many of the parties are working, it would be unduly burdensome and impractical to produce them in hard copy. Further, the supporting documentation is confidential, and as such would not be posted to the Commission's online docket for public review. In lieu of a physical production, consistent with the Commission's *Order for Notice and Comment* in Case No. PUR-2021-00066[9] and *Order Granting Limited Reconsideration* in Case No. PUR-2021-00146,[10] the Company requests a limited waiver of this

[9] Order for Notice and Comment at 12, *Petition of Appalachian Power Company For a prudency review, pursuant to § 56-585.1:4 H of the Code of Virginia, with respect to the purchase of the Amherst Solar Facility*, Case No. PUR-2021-00066, Doc. Con. Cen. No. 211210222 (Dec. 7, 2021).

[10] Order Granting Limited Reconsideration, *Petition of Virginia Electric and Power Company for Approval of the RPS Development Plan, approval and certification of the proposed CE-2 Solar Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under § 56-585.1 A 6 of the Code of Virginia, and a prudence determination to*

Rule to permit it to file one hard copy of these confidential documents, accompanied by three compact disks containing electronic versions of the documents. In addition, the Company has made available electronic copies of these documents to the Division of Utility Accounting & Finance and the Division of Public Utility Regulation, and will make them available for review by any respondents in an iManage folder established for this proceeding.

Finally, the Company requests, pursuant to Rule 20VAC5-204-10.E, that the Commission grant a limited and ongoing waiver, for good cause shown, of the requirement to file the documents in future petitions on "any changes in projected costs," and permit the Company instead to file all new or changed contracts supporting E-RAC costs that are worth more than $75,000. The Company selected $75,000 as a reasonable cutoff point that would provide Staff the most significant new and changed contracts. The Company will provide Staff with a list of all contracts under $75,000 and will provide copies of any that Staff wishes to review in its entirety. The Commission granted a similar request in Case No. PUR-2021-00047.[11]

WHEREFORE, Appalachian respectfully requests that the Commission 1) approve the Company's request to implement a rate adjustment clause to recover costs that were and will be incurred to comply with state and federal environmental laws or regulations; 2) approve the proposed revenue requirement, cost allocation, rate design, accounting treatment and rate year; and 3) grant the requests for waiver.

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enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia, Case No. PUR-2021-00146, Doc. Con. Cen. No. 210830286 (Aug. 26, 2021).

[11] Order for Notice and Hearing at 2, 3 and 13, *Petition of Appalachian Power Company For revision of a rate adjustment clause pursuant to § 56.585.1 A 6 of the Code of Virginia with respect to the Dresden Generating Plant*, Case No. PUR-2021-00047, Doc. Con. Cen. No. 210050009 (June 28, 2021).

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Respectfully submitted,

APPALACHIAN POWER COMPANY

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Counsel for Appalachian Power Company

Dated: March 18, 2022

220322-0301

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Petition of Appalachian Power Company was served by electronic mail on this 18th day of March 2022 to:

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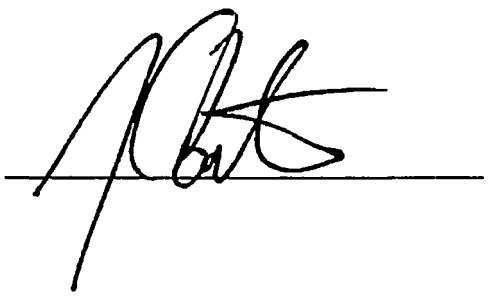

Appalachian Power Company- Virginia PUR-2022-00001					
Schedule 46 - Projected Rate Adjustment Clause Pursuant to § 56-585.1 A 5 e of the Code of Virginia					
Rate Case Rule	**Schedule 46 Index**	**Witness Sponsor**	**Section**	**Statement**	**Description**
20VAC5-204-90 Schedule 46 c 1	i.An updated schedule of all projected and actual costs by type of cost and year and by month to the extent available. The applicant shall provide such information by project if applicable for the specific rate adjustment clause.	BDS	1	1	Amos/Mountaineer
		RAG		1	Claytor Lake
20VAC5-204-90 Schedule 46 c 1	iii. Key documents supporting the projected and actual costs recovered through the rate adjustment clause, such as: economic analyses, support used by senior management for major cost decisions as determined by the applicant, contracts, studies, investigations, results from requests for proposals, cost-benefit analyses, and other items supporting the costs that have not been provided in previous applications.	JFM	2	1	Economic Analysis
		BDS/RAG		2	Documents, contracts, studies, and investigations to support projected costs
20VAC5-204-90 Schedule 46 c 1	ii. Within five business days of the application filing date, the applicant shall provide transaction-level details to facilitate the sampling and audit of such actual costs electronically to the Division to Utility Accounting and Finance in an electronic spreadsheet with all underlying formulas and assumptions. If the rate adjustment clause update includes a true-up, provide such information for costs incurred during the true-up period. If the rate adjustment clause does not include a true-up, provide the information based on most current actual costs available to-date.	THR	3	1	Over/Under Recovery workbooks (October 2021-December 2021)
20VAC5-204-90 Schedule 46 c 1	iv. The annual revenue requirement over the duration of the proposed rate adjustment clause by year and by class on a total company and Virginia jurisdictional basis, including all supporting calculations and assumptions. The applicant shall provide such information by project if applicable for the specific rate adjustment clause.	THR/WKC	4		Revenue Requirement Calculation
20VAC5-204-90 Schedule 46 c 1	v. Detailed information relative to the applicant's methodology for allocating the revenue requirement among rate classes and the design of class rates.	WKC	5		Allocation of Revenue Requirement/Revenue by Class
20VAC5-204-60	Rate adjustment clause filings. An application for a rate adjustment clause filed pursuant to Chapter 23 (§ 56-576 et seq.) of Title 56 of the Code of Virginia shall include Schedule 46 as identified and described in 20VAC5-204-90, which shall be submitted with the utility's direct testimony. Additionally, applications requiring an overall cost of capital shall include Schedules 3, 4, 5, and 8.	WKC	6		Cost of Capital Schedules

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Glossary of Terms

2020 Triennial Review	Commission Case No. PUR-2020-00015
2021 E-RAC Order	Order Granting Rate Adjustment Clause, Commission Case No. PUR-2020-00258 (August 23, 2021)
2021 E-RAC Proceeding	Commission Case No. PUR-2020-00258
2021 VCEA Proceeding	Commission Case No. PUR-2021-00206
ADIT	Accumulated Deferred Income Tax
ADITC	Accumulated Deferred Investment Tax Credit
AEP	American Electric Power Company, Inc.
AEPSC	American Electric Power Service Corporation
AFUDC	Allowance for Funds Used During Construction
APCo or Company	Appalachian Power Company
ARO	Asset Retirement Obligation
ARAM	Average Rate Assumption Method
Aurora model	Used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation.
AVT	Auto-venting Turbines
BATW	Bottom Ash Transport Water
CCOS	Class Cost of Service Study
CC	Combined Cycle
CCR Rule	Coal Combustion Residuals Rule
Claytor	Claytor Lake Hydroelectric Project
Clinch River	Clinch River Plant
CLR	Capability Load and Reserve Analysis
CO_2	Carbon Dioxide
Code	Code of Virginia
Commission or SCC	The Virginia State Corporation Commission
CT	Combustion Turbine
CWIP	Construction Work in Progress
DBA	Dry Bottom Ash
DEQ	Virginia Department of Environmental Quality
DO	Dissolved Oxygen
Dominion	Virginia Electric & Power Co. d/b/a Dominion Energy Virginia
DSIT	Deferred State Income Tax
DSI	Dry Sorbent Injection
EIA	Energy Information Administration
EIA AEO 2020	EIA's Annual Energy Outlook 2020
ELG Rule	Effluent Limitation Guidelines
EPA	U.S. Environmental Protection Agency
E-RAC	Environmental Rate Adjustment Clause
E-RAC Statute	Va. Code § 56-585.1 A 5 e
ERCOT	Electric Reliability Council of Texas

FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FRR	Fixed Resource Requirement Plan
FRR OAD	Fixed-Resource Requirement Open Access Distribution
Fundamentals Forecast	North American Long-Term Energy Market Forecast
GAAP	Generally Accepted Accounting Principles
G-RAC	Generation Rate Adjustment Clause
I&M	Indiana Michigan Power Company
IRP	Integrated Resource Plan
KPCo	Kentucky Power Company
kW	Kilowatt
kWh	Kilowatt-hour
MATS	Mercury and Air Toxics Standards Rule
MOPR	Minimum Offer Price Rule
MW	Megawatt
MWh	Megawatt-hour
NO_x	Nitrogen Oxide
NPDES	National Pollution Discharge Elimination System
NPV	Net Present Value
O&M	Operations and Maintenance
OAD	Open Access Distribution
OPCo	Ohio Power Company
OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection LLC
PLEXOS®	Modeling software tool
PowerTax	Power Plant Software
PPA	Purchase Power Agreement
Projects	Environmental improvement projects at the Amos and Mountaineer Plants
PSO	Public Service Company of Oklahoma
RAC	Rate Adjustment Clause
Rate Case Rules	The State Corporation Commission's Rules Governing Utility Rate Applications and Annual Informational Filings, 20 VAC 5-204-0, *et seq.*
Regulation Act	Virginia Electric Utility Regulation Act, Va. Code §§ 56-576 – 596.3
RFI	Request for Information
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RPS	Renewable Portfolio Standard
RPM	PJM Reliability Pricing Model
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide

Staff	State Corporation Commission Staff
SWEPCO	Southwestern Electric Power Company
TDI	Tailrace Dissolved Oxygen
UCAP	Unforced Capacity
VCEA	Virginia Clean Economy Act
WPCo	Wheeling Power Company
WVPSC	Public Service Commission of West Virginia
WVPSC August Order	Case No. 20-1040-E-CN (August 4, 2021)
WVPSC CCR/ELG Proceeding	WVPSC Case No. 20-1040-E-CN
WVPSC October Order	Case No. 20-1040-E-CN (October 12, 2021)
WWT	Wastewater Treatment

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CHRISTIAN T. BEAM
Direct Testimony

APCo Exhibit No. __
Witness: CTB

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DIRECT TESTIMONY OF
CHRISTIAN T. BEAM
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00001

APCo Exhibit No. __
Witness: CTB

SUMMARY OF DIRECT TESTIMONY OF CHRISTIAN T. BEAM

In my testimony, I

- Describe the outcome of the CCR/ELG proceeding before the WVPSC and how it led APCo to make another request for ELG investment cost recovery from APCo's Virginia customers;
- Explain the practical impact of the WVPSC's Order on Virginia customers; and
- Set out the options available to the Commission and the potential costs that Virginia customers would face if the Commission again denies ELG investment cost recovery from APCo's Virginia customers.

APCo Exhibit No. __
Witness: CTB

DIRECT TESTIMONY OF
CHRISTIAN T. BEAM
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00001

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Christian T. Beam. My business address is 500 Lee Street, East, Charleston, West Virginia 25301. I am the President and Chief Operating Officer of APCo and WPCo, both operating companies of the AEP System.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor's Degree in Applied Science, with a focus on project management, from DeVry University. I am a certified Project Management Professional and completed the AEP Leadership Program at The Ohio State University in 2007 and The Executive Program: Strategic Leadership at the University of Virginia's Darden School of Business in 2019. I have held positions of escalating responsibility at AEP companies since I started with Ohio Power Company in 1990. I worked first in the Utility Operations department at the Kammer Plant. In 1997, I moved to the AEP Service Corporation and was named Outage Project Supervisor for the Regional Service Organization serving the Kammer, Mitchell, and Cardinal Plants. In 2000, I assumed a new role as Superintendent for the Regional Service Organization, supporting SWEPCO, and subsequently became Manager - Region Outage Management in 2002. In 2004, I was named Manager for the Flue Gas Desulphurization retrofit project at the Mountaineer Plant. I became Manager - Construction Technology in 2007 and then Director - Construction in 2008. In 2009, I was named the Project Director - Environmental Retrofit Projects. I was named Managing Director Projects and

Construction in November 2010. I assumed the position of Vice-President - Projects, Controls, and Construction in 2013. In January of 2017, I was named President and Chief Operating Officer of APCo and WPCo.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS PRESIDENT OF APCO.

A. I oversee all aspects of APCo, Kingsport, and WPCo, including their day-to-day operations. My primary goals are to see that they are operated in a responsible and efficient manner and to ensure that customers receive safe and reliable electric service at a reasonable price.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?

A. Yes. I have testified before this Commission on several occasions, most recently in Case No. PUR-2020-00258, APCo's most recent E-RAC proceeding. In addition, I have filed testimony before the Public Service Commission of West Virginia in Case No. 11-0274-E-PC, before the Arkansas Public Service Commission in Docket No. 12-008-U, and before the Public Utility Commission of Texas in Docket Nos. 39708 and 40443.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to:

- Describe the outcome of the CCR/ELG proceeding before the WVPSC and how it led APCo to make another request for ELG investment cost recovery from APCo's Virginia customers;
- Explain the practical impact of the WVPSC's Order on Virginia customers; and
- Set out the options available to the Commission and the potential costs that Virginia customers would face if the Commission again denies ELG investment cost recovery from APCo's Virginia customers.

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I. BACKGROUND

Q. WHY IS THE COMPANY FILING THIS PETITION?

A. The Company files this Petition pursuant to the E-RAC Statute for two central purposes: to seek recovery of costs related to compliance with state and federal environmental laws and regulations that are applicable to the generation facilities APCo uses to serve its native load obligation, as described in the testimony of Company witnesses Spitznogle, Sherrick, and Gallimore; and to ask again the Commission's permission to recover costs from our Virginia customers that are necessary to comply with the ELG Rule at the Amos and Mountaineer Plants. The Company makes this second request pursuant to the 2021 E-RAC Order in which the Commission denied recovery of the ELG costs from Virginia customers without prejudice and stated that the Company could re-file for approval "should circumstances so warrant." I will explain below the current circumstances that necessitate this filing.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE PREVIOUS E-RAC PETITION, AS WELL AS THE REGULATORY FILINGS IN OTHER JURISDICTIONS RELATED TO THE PLANTS.

A. On December 23, 2020, APCo filed a petition for authority to recover through the E-RAC:

- costs of compliance with the CCR Rule at the Plants, which the Commission approved;
- costs of compliance with the ELG Rule at the Plants; which the Commission denied without prejudice; and
- O&M costs related to compliance with rules governing the handling and disposal of fly ash, bottom ash, and FGD by-product, which the Commission approved.

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The Commission's decision regarding the ELG Rule in the 2021 E-RAC Order effectively closed the Plants to Virginia customers the end of 2028, which is the last day the plant may combust coal if it chose to not make necessary modifications for ELG compliance.

On December 23, 2020, APCo also filed a petition with the WVPSC seeking certificates of convenience and necessity that would authorize both the CCR and ELG projects at the Plants, as well as a cost recovery mechanism. The WVPSC approved the requests on August 4, 2021. In the WVPSC August Order, the WVPSC found that the CCR and ELG Projects at the Plants were "prudent, cost effective, and in the best interest of the current and future utility customers." On October 12, 2021, the WVPSC issued another order that affirmed its earlier holdings and concluded that, given the 2021 E-RAC Order, the West Virginia jurisdictional customers would pay for the ELG projects at the Plants, and should also receive the benefit of capacity and energy made possible by the ELG projects starting January 1, 2029.

Q. WHAT IS THE PRACTICAL IMPACT OF THE WVPSC'S ORDERS ON VIRGINIA?

A. Simply put, the Plants will continue to operate and dispatch into PJM past 2028, regardless of the Commission's decision in this proceeding. If the Commission rules that APCo's Virginia customers should not pay for the ELG projects, APCo's West Virginia customers will pay all the costs, and, the WVPSC asserts, APCo's Virginia customers should receive none of the energy or capacity produced by the Plants after 2028. The WVPSC's orders make clear that West Virginia is committed to keeping the Plants operating.

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II. IF THE COMMISSION APPROVES ELG COST RECOVERY

Q. PLEASE DESCRIBE THE IMPACT OF THE COMMISSION'S APPROVAL OF ELG PROJECT COST RECOVERY FROM VIRGINIA CUSTOMERS IN THIS PROCEEDING.

A. If the Commission approves APCo's request in this Petition, nothing will change for its Virginia customers. They will continue to pay for the Virginia jurisdictional share of all investment, including ELG project investment, at the Plants, as well as O&M costs, and will continue to receive the benefit of their energy and capacity after 2028, as long as the Plants continue to run.

Q. PLEASE DESCRIBE THE COSTS THAT VIRGINIA CUSTOMERS WILL BEAR AND AVOID IF THE COMMISSION APPROVES ELG COST RECOVERY IN THIS PROCEEDING.

A. Company witness Martin's analysis shows that, if approved, our Virginia customers will pay approximately $15 million the first year and $150 million in total over the period through 2040 for depreciation and return on their $98 million share of those investments. In exchange, they will continue to benefit from the 2,100 MW (nameplate) jurisdictional share of capacity provided by the Plants, which will continue to operate regardless of the Commission's action in this proceeding. And, absent a complicated interstate, intracompany arrangement that I will discuss more, Virginia customers will avoid:

- Paying $3 or $4 billion for 2,700 MW or more of nameplate replacement capacity to be in place by 2028, which could increase APCo's cost of service by an incremental 17-21% in 2029 over what they paid in 2021.
- Being responsible for a revenue requirement for that replacement capacity in the amount of $1.8 billion to $2.35 billion from 2029-2040, compared to the incremental cost of keeping the Plants operating through 2040 of $1.0 billion.

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This assumes, of course, that APCo could construct and/or procure that much capacity in the pre-2028 timeframe.

- Possibly being subject to the uncertainty and volatility of capacity provided solely by the market (paper capacity).

From my perspective, as the President of APCo, as the person responsible for providing our customers with reliable energy as cost effectively as reasonably possible, approving the ELG project costs and allowing our customers to avoid these astronomical costs and uncertainty seems like the most prudent course of action, especially given the comparatively limited cost and revenue requirement.

Q. WHAT IMPACT WOULD APPROVAL OF ELG PROJECT COST RECOVERY FROM VIRGINIA CUSTOMERS HAVE ON APCO'S COMPLIANCE WITH THE VCEA?

A. None. The Company will continue to comply with the mandates in the Code to seek Commission approval to own renewable facilities, enter into renewable PPAs, and otherwise procure and retire RECs. It is important to note, as Company witness Martin explains, the total UCAP provided by the renewable resources planned for VCEA compliance is less than the amount of capacity needed to offset even the smallest unit at Amos until 2035. In addition, the VCEA does not place energy production restrictions on the Plants. Continued operation of the Plants will not cause APCo to fail to comply with the VCEA's renewable energy mandates, which are based on a percentage of energy load, not energy generation. APCo plans to meet those targets with renewable resources, which will be added with or without the Plants.

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III. IF THE COMMISSION DENIES ELG COST RECOVERY

Q. WHAT HAPPENS IF THE COMMISSION DENIES ELG PROJECT COST RECOVERY FROM VIRGINIA CUSTOMERS?

A. If the Commission denies recovery of the ELG investment, Virginia customers would avoid the O&M expenses and capital investment costs necessary to keep the Plants operating past 2028. But, by not paying its jurisdictional share of an investment necessary to keep the Plants operating past 2028, Virginia will have shifted a disproportional share of costs onto a different jurisdiction.

As APCo would have to find a way to replace the energy and capacity that the Plants have provided to its Virginia customers for decades, an equitable arrangement could be made whereby Virginia customers compensate West Virginia customers for the capacity provided by one or both Plants. This arrangement could take many forms, and would be very complicated, requiring approval in both jurisdictions. For energy, APCo could purchase replacement energy from PJM for its Virginia customers, but they would be more exposed to energy market volatility. Note that energy on the PJM market is overwhelmingly generated from fossil fuels: for example, per PJM, on March 14, 2022 at noon, a relatively clear and sunny day across the PJM, renewables accounted for only 12,324 MW of the 98,829 MW in load. Eschewing the energy generated from the Plants in favor of market energy would not materially advance any clean energy goals. In short, Virginia customers would likely still rely on the Plants for capacity, but in a more convoluted way, and would be more exposed to volatility in the PJM energy market, which is overwhelmingly fossil-based.

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Q. IF THE COMMISSION DENIES ELG COST RECOVERY IN THIS PROCEEDING, WILL VIRGINIA CUSTOMERS AVOID PAYING ANY COSTS RELATED TO THE PLANTS?

A. No. In addition to possibly making some type of intracompany, inter-jurisdictional capacity payment to West Virginia customers, Virginia customers will continue to be responsible for the undepreciated balance of the Plants for which those customers are responsible. This is both fair and in line with traditional utility practice. Company witness Ross provides APCo's forecasted December 31, 2028 remaining book values of Amos and Mountaineer.

Q. WHAT WOULD BE THE IMPACT IF THE COMMISSION DENIES THE ELG PROJECT COST RECOVERY FROM VIRGINIA CUSTOMERS, AND ALSO DENIES ANY INTERSTATE, INTERCOMPANY ARRANGEMENT THROUGH WHICH VIRGINIA CUSTOMERS COMPENSATE WEST VIRGINIA CUSTOMERS FOR THE PLANTS' CAPACITY?

A. As Company witness Martin's analysis illuminates starkly, these Plants are hugely important to Virginia and our ability to keep rates reasonable: the Plants provide a considerable amount of inexpensive capacity that is not easily replaced. APCo could, theoretically, enter into the PJM market to acquire an equivalent amount of capacity from another source, which would likely be fossil fueled. APCo could also acquire or construct an equivalent amount of renewable resources to replace the Virginia share of jurisdictional capacity, but it is highly unlikely that APCo could accomplish this by 2028, given the time necessary to site, permit, and procure that much capacity. Note that PJM just recently proposed a two-year pause on reviewing projects in order to process a

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backlog of 1200 proposed projects, mostly solar, which could further complicate the timeline getting replacement capacity built. Moreover, it is unlikely that customers in West Virginia would pay for such an expensive investment, when it is simply not needed to serve them. This significant cost would most likely fall squarely on the shoulders of our Virginia customers, an outcome the Company is trying to avoid with this Petition.

Q. IF THE COMMISSION DENIES RECOVERY OF THE ELG INVESTMENT FROM VIRGINIA CUSTOMERS, WHAT IS THE IMPACT ON THE COMPANY'S CAPACITY POSITION WITH REGARD TO PJM?

A. None, as PJM views APCo as whole. Because the WVPSC affirmed the Plants' ability to operate past 2028, the Plants will continue to be an integral component of the Company's FRR capacity plan. The Plants will continue to dispatch economically, providing energy for the benefit of customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

JAMES F. MARTIN
Direct Testimony

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APCo Exhibit No. ____
Witness: JFM

220322001

DIRECT TESTIMONY OF
JAMES F. MARTIN
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00001

220220001

APCo Exhibit No. ____
Witness: JFM

SUMMARY OF DIRECT TESTIMONY OF JAMES F. MARTIN

In my testimony, I

- Describe an economic analysis that I provided to APCo management that compares the forecasted Virginia jurisdictional cost of service effects of a scenario in which the costs, energy, and capacity of the Amos and Mountaineer plants (the Plants) continue to benefit Virginia customers after 2028 to scenarios in which they do not. Elements of this analysis include:
    - Calculations of the $84 million average annual incremental cost to Virginia customers of continued operation of the Plants between 2029 and 2040, and an estimate of between $235 and $280 million average annual net cost over that same period of resources that could replace the Plants. Over that 12 year period, customers would pay between $1.8 billion and $2.35 billion more without the Plants than with them.
    - A computation of the 17-21% 2029 cost of service increase versus 2021, and 12-15% sustained average increase over the 2029-2040 period that Virginia customers will experience if they have to pay for new resources that would replace Virginia's jurisdictional share of the Plants in 2028.
- Explain the importance of APCo's PJM capacity requirement, and why that requirement is critical to understanding the economics of possible replacements of the Plants.
- Explain how PJM computes capacity credit for all of the primary alternative resource options that could replace the Plants (wind, solar, gas, and energy storage), in order to identify how many megawatts of capacity would be required to replace them, and I provide estimates of how much that capacity will cost.
- Discuss the impact of the VCEA on the evaluation of the merits of the ELG investment, and on the value of continued operation of the Plants in general.

APCo Exhibit No. ____
Witness: JFM

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DIRECT TESTIMONY OF
JAMES F. MARTIN
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00001

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is James F. Martin. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by AEPSC as a Director of Resource Planning Strategy. AEPSC, a wholly-owned subsidiary of AEP, provides centralized professional and other services to subsidiaries of AEP. AEP is the parent company of APCo.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from The Ohio State University in 1990, receiving a Bachelor of Science in Business Administration (Accounting Major), and again in 2001 receiving a Master's in Business Administration. Between 1990 and 2000, I held various accounting-related positions in private companies and public accounting firms. In 2000, I joined AEPSC as a Senior Accountant in the Corporate Development department. In 2001, I was promoted to Manager of Financial Analysis. In 2003, I became Manager of Strategic Analysis in Corporate Planning and Budgeting. In 2007, I was promoted to Director-Corporate Budgeting and Capital Investments. In August 2010, I became Manager-Regulated Pricing and Analysis in AEP's Regulatory Services department, with responsibility for preparing retail and FERC jurisdictional and class cost of service studies. In 2016, I was promoted to Regulatory Case Manager, with responsibilities including FERC generation and transmission cost

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of service studies, along with support for special projects including wind resource additions. In February 2021 I was promoted to my current position in AEP's Resource Planning group.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS A DIRECTOR OF RESOURCE PLANNING STRATEGY FOR AEPSC?

A. My responsibilities primarily include preparing and reviewing various resource planning analyses, including integrated resource plans (IRPs) for companies in the AEP system, using the Plexos® modeling software and spreadsheet models to evaluate future resource plan costs and benefits at both operating company and individual jurisdictional levels. Other responsibilities include levelized cost of energy analyses, evaluation and rankings of bids submitted into competitive solicitations for capacity and energy resources, and evaluations of costs and benefits of individual generating resources. In addition, I prepare custom financial modeling for special projects such as the economic analysis used in the recent Wind Catcher and North Central wind resource proposals by APCo affiliates Southwestern Electric Power Company and Public Service Company of Oklahoma.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY OR APPEARED BEFORE ANY ELECTRIC UTILITY COMMISSION OR OTHER REGULATORY BODIES?

A. Yes. I most recently submitted testimony with the Commission on behalf of APCo in support of an economic analysis I prepared supporting investments needed for compliance with both the federal CCR and ELG Rules at the Plants as part of the

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2021 E-RAC Proceeding. I provided similar testimony on behalf of APCo and Wheeling Power Company in the WVPSC CCR/ELG proceeding. I have submitted testimony in FERC Docket Nos. ER15-2114-000, ER17-419-000 and ER17-418-003 in support of the formula rate protocols and cost of service templates for AEP affiliates. I have also testified before the WVPSC in proceedings regarding Wheeling's purchase of a portion of the Mitchell Plant and potential merger with APCo.

In addition, I testified before the Commission on behalf of APCo in Case Nos. PUE-2011-00037 (regarding jurisdictional cost-of-service, revenue allocation, and rate design); PUE-2011-00036 (regarding the Dresden generation rate adjustment clause); and PUE-2011-00001 (regarding demand response programs).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an analysis that compares the investment in the ELG Projects at the Plants to the option of assuming that the Plants are no longer available to Virginia customers. My analysis demonstrates clearly that continued operation of the Plants, even if they do not run at all, is less expensive and much less risky for customers than retiring them early and replacing them. Having the Plants and their 4,200 MW of capacity allows the Company to avoid incurring substantial cost to obtain another source of capacity to cover its PJM capacity obligation. The Virginia share of the ongoing non-fuel costs of operating the Plants is about $84 million annually, or around $100 per MW per day. Annual revenue requirements of replacement resources would cost 2.5-3.5 times that amount.

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In sum, my analysis demonstrates that:

1. The relatively small $98 million jurisdictional share of the ELG investments and continued use of the Plants will be much less expensive than replacing them with billions of dollars of new resources;
2. Replacement capacity would increase customers' rates by an incremental 17-21% in 2029;
3. In total, between 2029 and 2040, the net cost of service for the replacement resources would be between $2.8 billion and $3.4 billion, compared to the incremental cost of keeping the Plants operating of $1.0 billion; and
4. The above is true even if the Plants don't generate a single MWh of electricity after 2029, due to their capacity value.

Thus, my analysis provides compelling evidence that the Commission should approve cost recovery from APCo's Virginia customers for the ELG investments, so that customers can continue to benefit from the Plants.

Q. ARE YOU SPONSORING ANY SCHEDULES OR EXHIBITS IN THIS PROCEEDING?

A. I am sponsoring the Company's economic analysis included in APCo Schedule 46, Section 2, Statement 1. In addition, I am sponsoring the following schedule, which is attached to my testimony:

- APCo Exhibit No. __ (JFM) Schedule 1 – VCEA Report

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR ANALYSIS.

A. My analysis is comprised of three scenarios. First, I prepared two cases, both of which are VCEA compliant, in which Virginia's half of the Plants were assumed to be replaced with physical resources in 2028, in order to assess if the Plants were more or less expensive than other resource options. Case 1 assumes replacement of the Plants with a mix of renewables and gas-fired resources (the thicker dotted line on

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Figures 1 and 2 below). Case 2 assumes replacement with 100% renewable and energy storage resources, with energy storage being the bulk of the replacement capacity (the thinner dotted line on Figures 1 and 2). I also compared the ongoing cost of operating the Plants to a PJM market capacity price projection (the paper capacity case, which is the combination dashed/dotted line on Figures 1 and 2). I compared the ongoing costs of keeping the Plants operating (the future fixed O&M and capital expenses from 2028 onward) to the other options. Amos is the dashed line, and Mountaineer is the solid line. The Plants are the two lowest lines on both graphs.

Figures 1 and 2 illustrate the results of my analysis in terms of both gross and net capacity costs per MW-Day. In my analysis, "gross capacity costs" are the fixed costs of the capacity other than sunk costs, and "net capacity costs" are the fixed costs minus the energy margin expected from the resource option. For this analysis I didn't count the fact that the Plants would generate energy margin to offset that capacity cost, so the gross and net lines are the same between the two graphs. As the Plants do not need energy margin to provide tremendous value to customers versus other options, I omitted that factor. In reality, the Plants will generate energy margin, so the net line would be lower than the gross line, increasing the cost advantage.

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The assumed PJM market capacity option would not come with any energy margin offset, so those lines are also the same on the two graphs. In Figure 2, Cases 1 and 2 have the energy margin deducted.

Figure 1 - Gross Capacity Costs - $/MW-Day

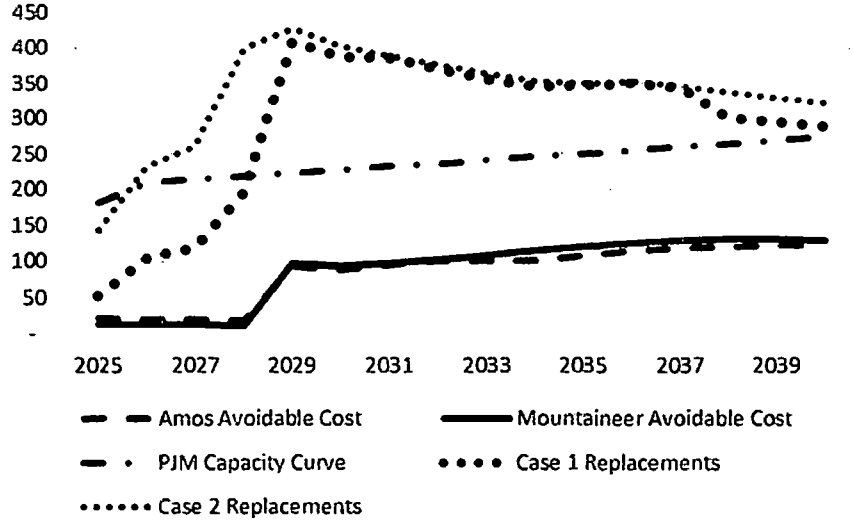
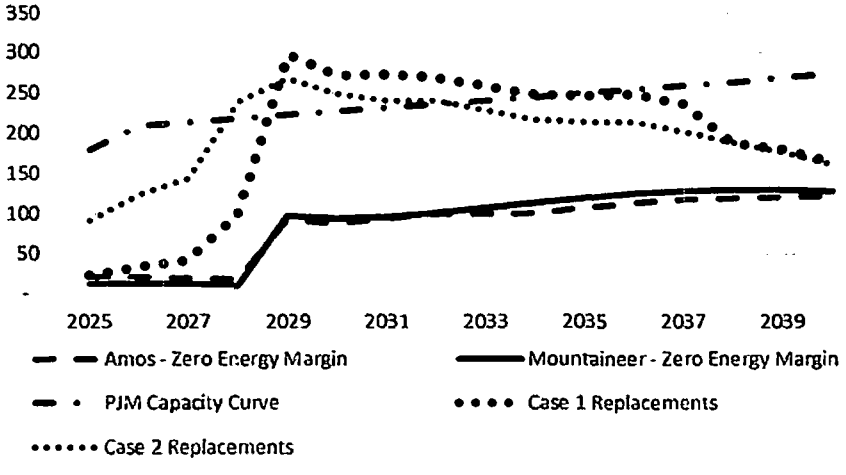


Figure 2 - Net Capacity Costs - $/MW-Day



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Q. PLEASE EXPLAIN WHAT IS PRESENTED IN FIGURES 1 AND 2.

A. Figures 1 and 2 are presented in terms of Dollars per Megawatt-Day ($/MW-Day), which is the unit of measure that PJM uses for its capacity auction price, and is a common measure of the cost of capacity. This metric puts differently sized capacity resources on an apples-to-apples basis as a cost per unit of capacity. The first year presented is 2025, which is the year that most of the new resources to be used for near-term VCEA compliance are projected to come online. The final year presented for purposes of my analysis is 2040, as the WVPSC approved the ELG projects at the Plants and indicated it would provide the Company an opportunity to run the Plants through 2040. Later in my testimony, I provide the underlying costs behind Figures 1 and 2 in millions of dollars of cost of service, which is another way to evaluate capacity cost.

The graphs show that the Plants are far less expensive than the other three options over the entire period through 2040. Figure 2 shows that the net costs of all the capacity options are 2-3 times the cost of the Plants in 2029, the year in which replacement capacity would need to be online to comply with APCo's PJM capacity obligations. Even though the relative cost advantage of the Plants then declines versus the physical resource options in Cases 1 and 2 through the 2030s, the Plants remain the least expensive capacity option through 2040.

The gross capacity cost in Figure 1 is similar to base rate cost of service, containing the incremental fixed costs of each option net of tax credits for the wind and solar resources. Those fixed costs of the replacement resources become sunk

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costs the minute the investments are made. Customers would need to pay for the replacements regardless of what happens in years after that. It is important to isolate the costs of just those replacement resources for the purpose of evaluating the value of making the ELG investment and operating the Plants beyond 2028.

Q. WHY DOES YOUR ANALYSIS ASSUME THAT THE PLANTS WILL NOT BENEFIT VIRGINIA CUSTOMERS AFTER 2028?

A. As described in the testimony of Company witness Beam, the WVPSC ordered the Company to make the ELG investments at the Plants. Therefore, the Plants will operate beyond the 2028 ELG compliance deadline regardless of the outcome of this proceeding. The WVPSC stated that if the Commission did not approve recovery of the ELG investment from Virginia customers, Virginia customers would not be entitled to the capacity and energy from the Plants, and the West Virginia customers would accept responsibility for the ELG investment and all ongoing operating costs after 2028. If this occurs, Virginia customers would no longer benefit from the capacity and energy of the Plants, despite their continued operation, but the Virginia jurisdiction would continue to be responsible for its share of APCo's overall capacity obligation. As that obligation will be met, in large part, with the Plants, Virginia customers could satisfy their responsibility with an inter-jurisdictional financial agreement or, conceivably, self-supply of the Virginia capacity obligation. Company witness Beam discusses the former, and the latter is the subject of my analysis.

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I. CAPACITY REPLACEMENT ANALYSIS.

Q. PLEASE DISCUSS THE BASIC STRUCTURE OF YOUR ANALYSIS.

A. My analysis compares the incremental cost of service of continued operation of the Plants beyond 2028, the "avoidable costs," to the costs of new resources, net of energy margin, from two portfolios of specific resources that would be needed to replace the Plants. I also compare the Plants to a paper capacity option priced at the forecasted PJM capacity market price. The avoidable costs of the Plants include fixed O&M and all capital expenses after 2028, and the $98 million Virginia share of the ELG capital investments. For the replacement resources, costs and revenues associated with resources added after 2028, such as resources the Company expects to add to comply with the VCEA, or to replace other Company resources when they retire, are irrelevant to the ELG approval decision, as they will come too late to allow customers to avoid paying for the required pre-2028 investments. My analysis eliminates all impacts of separate and unrelated resource additions or retirements occurring after 2028.

Q. HOW MUCH CAPACITY IS REPRESENTED BY VIRGINIA'S SHARE OF THE PLANTS?

A. The nameplate capacity of the Plants is approximately 4,200 MW. For the purpose of using the Plants to comply with the Company's PJM capacity obligation, the UCAP value of the Plants, after a forced outage rate adjustment made under PJM's rules, is expected to be 3,814 MW, as I discuss below. For this analysis, I combined the roughly 3% of APCo's load comprised of the Commonwealth and Public Authorities

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customers with the ~47% Virginia retail jurisdiction, because rates for those customers are based on the same cost of service as the retail jurisdiction. Virginia's half of the Plants' PJM accredited capacity would thus be 1,907 MW UCAP. I solved for this amount of replacement capacity for Virginia in my analysis.

Q. WHAT ARE THE AVOIDABLE COSTS?

A. As I discussed in more detail below, I estimate that the Virginia jurisdictional share of the ongoing avoidable costs of the Plants, including avoidance of the ELG investment, would be around $73 million in 2029, and would average $84 million annually from 2029-2040. By 2040 I project that amount to have increased to $95 million due to the cumulative effect of not paying a return on future capital expense. For this analysis, I excluded recovery of the sunk costs of the existing investment in the Plants from Virginia customers, as the Company would recover them in any scenario, either as depreciation should the Plants continue to run, or amortized over a given period, if the Plants are replaced.

Q. HOW DID YOU DETERMINE WHICH REPLACEMENT RESOURCES TO EVALUATE?

A. In Case 1 and 2, I used resources selected by the Plexos model in two of the resource plan scenarios included in the 2021 VCEA RPS Plan, which is attached to my testimony as APCo Exhibit No. ___ (JFM) Schedule 1 (the VCEA Report). In the VCEA Report, six VCEA compliant portfolios were prepared to illustrate various plans to comply with the VCEA's renewable energy requirements under futures with and without the Plants. The fundamental forecasts used in the VCEA analysis

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accounted for the expected build-out of renewables in Virginia and PJM, as well as Virginia's participation in RGGI.

Two of those VCEA Portfolios assumed a 2028 retirement of the Plants, and showed that retiring them in 2028 would be more costly than the VCEA Portfolios that kept the Plants running through 2040. I used the resources added up through 2028 in these VCEA Portfolios as the basis for the inputs to my two cases in this proceeding: Case 1 is based on VCEA Portfolio 3, which replaced the Plants with a mixture of renewables and gas-fired resources; and Case 2 is based on VCEA Portfolio 4, which relies on 100% renewable resources and energy storage. The full resource plans for those VCEA Portfolios, with both nameplate and firm (UCAP) capacity, is presented in Tables 26 and 27 in the VCEA Report.

In addition, I also evaluated what it would cost to replace the Plants with market purchase (paper capacity). This option would leave the Company heavily exposed to both market energy and capacity price risks that would be mitigated with ownership of actual resources.

Q. HOW DID YOU ALLOCATE THESE RESOURCES TO VIRGINIA IN YOUR TWO CASES?

A. Both of these VCEA Portfolios were prepared as if all of the Plants' 4,200 MW of capacity was retired and replaced. For this analysis, to better isolate the effects on Virginia, I only extracted enough resources from those VCEA Portfolios to replace Virginia's half of the Plants by making the following assumptions:

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1. If approved, the mixture of owned and PPA wind and solar projects that were selected from the 2021 RFP's totaling 498 MW[1] pending before the Commission in the 2021 VCEA Proceeding will come online at various dates between 2023 and 2025. I assumed that both Virginia and West Virginia would approve the projects, and Virginia would thus be allocated half.
2. The next group of resources added between 2025 and 2028 were assumed to be fully allocated to the Company's Virginia jurisdiction to meet the VCEA requirements. Between steps 1 and 2, all of the resources required by the VCEA prior to 2028 have been brought in to the analysis, reducing the replacement capacity that would otherwise be required to replace the Plants.
3. The "plug" to fully replace the remaining portion of Virginia's half of the Plants' UCAP capacity was then taken from the large resource added to replace the retiring coal plants in the two VCEA portfolios in 2028. This is a gas combined cycle in Case 1, and energy storage in Case 2.

Q. WHAT DO THESE PORTFOLIOS LOOK LIKE IN TERMS OF CAPACITY BY RESOURCE TYPE AND COST?

A. The capacity by resource type and costs for the Company's Virginia jurisdictional customers are presented in Tables 1 and 2. The capacity is presented in both nameplate (ICAP) and UCAP megawatts, which is what governs PJM capacity obligation compliance. For example, 200 MW of wind would give APCo 22 MW of PJM accredited capacity due to its intermittent nature under PJM's capacity market construct. Both Cases add up to 1,907 UCAP MW (half of the UCAP of the Plants). Cost amounts are presented in millions of dollars.

[1] See VCEA Report Table 2.

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Table 1 - Case 1 Replacement Resource Plan Cost

	Case 1 - Virginia Jurisdictional				
Resource Type	MW Nameplate	MW UCAP	Capital Cost ($MM)	2029 Gross Cost of Service ($MM)	2029 Net Cost of Service ($MM)
Under Development Wind/Solar	249	54	$420	$40	$18
Generic Owned Wind	200	22	$311	$25	$6
Generic PPA Wind *	150	17	$216	$20	$5
Generic Owned Solar	-	-	$0	$0	$0
Generic PPA Solar *	300	117	$355	$33	$12
Storage	300	210	$321	$61	$59
Hybrid Solar/Storage	0	0	$0	$0	$0
EE / VVO	67	67	$0	$19	$2
Gas CC	1,420	1,420	$1,546	$203	$188
Totals	2,686	1,907	$3,169	$400	$291

* PPA Capital Investment by PPA Counterparty. PPA cost is PPA price times energy

Table 2 - Case 2 Replacement Resource Plan Cost

	Case 2 - Virginia Jurisdictional				
Resource Type	MW Nameplate	MW UCAP	Capital Cost ($MM)	2029 Gross Cost of Service ($MM)	2029 Net Cost of Service ($MM)
Under Development Wind/Solar	249	54	$420	$40	$13
Generic Owned Wind	200	22	$309	$25	$2
Generic PPA Wind *	100	11	$142	$12	($0)
Generic Owned Solar	600	234	$843	$88	$37
Generic PPA Solar *	300	117	$388	$33	$7
Hybrid Solar/Storage	197	93	$280	$27	$14
EE / VVO	178	178	$0	$27	($10)
Storage	1,711	1,198	$1,862	$299	$284
Totals	3,535	1,907	$4,244	$551	$346

* PPA Capital Investment by PPA Counterparty. PPA cost is PPA price times energy

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The 2,686 MW (nameplate) of resources required in Case 1 (Table 1) to replace Virginia's half of the Plants' capacity would cost $3.2 billion. This assumes approximately 1,420 MW of the capacity is replaced by gas. In Case 2 (Table 2), 3,535 MW (nameplate) of resources costing $4.2 billion would be needed to replace half of the Plants with 100% renewables, with 1,711 MW of energy storage as the primary replacement resource.

I presented the Virginia jurisdictional cost of service in 2029 in the two Tables, which is the first year all of the revenue requirements of all of the new resources are fully included in cost of service. This year illustrates the immediate cost of service impact of replacing the Plants, costing Virginia ratepayers $291 million dollars that year if a combined cycle plant replaces the bulk of the capacity. This amount would be $346 million in 2029 if energy storage is the primary replacement resource. Both of these amounts are net of fuel savings customers would expect to receive from all new resources.

Q. HOW MUCH WOULD THE 2029 SINGLE YEAR COST OF SERVICE INCREASE BE UNDER THESE SCENARIOS?

A. These new resource costs would be offset by the avoided ongoing costs at the Plants, which I estimate will be $73 million in 2029. I did not include any energy margin the Plants might generate, in order to make my analysis as conservative as possible. The resultant net increase in 2029 cost of service would be $218 million in Case 1 and $273 million in Case 2, even if the Plants do not generate a single megawatt hour of energy. In comparison, Virginia customers paid a total of $1.3 Billion for regulated

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electric service (generation, transmission and distribution) from APCo in calendar year 2021. This incremental cost would amount to a customer rate increase of between 17 and 21% in 2029 above what they paid in 2021.

Q. WHAT WOULD THE TOTAL AND AVERAGE COST OF SERVICE INCREASE BE OVER THE 2029-2040 PERIOD?

A. See Table 3 below. In total, over the period between 2029 and 2040, the net cost of service for these replacement resource options would be $2.8 billion in Case 1 and $3.4 billion in Case 2. The paper capacity option would cost $2.3 billion during that period. In contrast, the incremental cost of keeping the Plants operating would be $1.0 billion. The annual average revenue requirement of the replacement resources included in these 12-year totals, net of fuel savings, is expected to be $235 million in Case 1 and $280 million in Case 2. These amounts are 2.8 to 3.3 times higher, respectively, than the $84 million average annual cost to keep the Plants operating during that period.

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Table 3 - 2029-2040 Cost of Service Impacts

Line	Dollars In Millions	NPV of 2029-2040	Nominal Total 2029-2040
1	**Amos and Mountainer incremental capacity cost**	$647	$1,003
	Replacement Capacity Costs, net of Energy Margin		
2	Case 1 - Gas CC and Renewable Replacements	$1,935	$2,825
3	Case 2 - Storage and Renewable Replacements	$2,290	$3,356
4	Paper Capacity - PJM Market	$1,486	$2,280
	Replacement Cost Percentage of Amos/Mountaineer	2029-2040 Average % Increase	2029-2040 Average $(Millions) Increase
5	Case 1 - Gas CC and Renewable Replacements	290%	$152
6	Case 2 - Storage and Renewable Replacements	344%	$196
7	Paper Capacity - PJM Market	229%	$106

Additional details supporting Table 3 in the form of the annual gross and net cost of service over the 2029-2040 period are shown in Schedule 46, Section 2, Statement 1, which I sponsor in this proceeding.

II. PJM CAPACITY REQUIREMENTS

Q. PLEASE DESCRIBE THE REQUIREMENTS APPLICABLE TO PJM MEMBER COMPANIES LIKE APCO.

A. PJM utilities such as APCo and the AEP system companies are required to provide enough capacity to cover their summer peak loads plus a reserve margin. This requirement is forecasted to be 14.9% on an ICAP or nameplate basis, or around 8.6% on an UCAP basis. The difference between the two is due primarily to two downward adjustments that PJM makes. First, each resource's nameplate capacity is reduced by an assumed forced outage rate. Second, for renewable resources, PJM

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uses a methodology called Effective Load Carrying Capability (ELCC) to determine how much credit each resource gets. These ELCC adjustments in my analysis are reflected in Tables 1 and 2 in the differences between the nameplate and UCAP columns.

A utility must maintain reserve capacity (Capacity – Peak Load) of at least 8.6% of UCAP above its peak load. For example, if a utility has a capacity of 1,086 UCAP MW and a peak load of 1,000 MW, then its reserve margin reserve would be 8.6% ((1,086 -1,000)/1,000).

Q. HOW MUCH CAPACITY DOES EACH POSSIBLE REPLACEMENT RESOURCE PROVIDE?

A. The PJM capacity market rules determine how much capacity credit each type of resource is given towards a capacity obligation, which varies widely based on each resource's ability to contribute dependable output during high load hours. RTOs plan for how much capacity is needed for peak load conditions, plus a reserve margin, in order to make sure enough resources are available to reliably serve load at those times. Looking at how much energy a given resource can be counted on to produce in those high load hours is how RTOs determine how much capacity credit each resource should be given. The ELCC method does this calculation for the intermittent resource types. In general, fossil fueled resources like gas and coal provide more capacity value due to their dispatchability than intermittent resources like wind and solar. If APCo found itself needing this much capacity, this assumption would be critically important.

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This is illustrated for PJM in Table 4. That table shows how much capacity credit each major resource type is expected to get in PJM, compared to Virginia's half of the Plants. Wind, for example, would get 231 MW of credit for its 2,100 MW nameplate capacity. It would take 17,336 MW of wind to equal the Plants 1,907 MW of UCAP.

Table 4 - PJM Capacity Credit By Resource Type

	Nameplate Capacity	2028 PJM Capacity credit %	PJM Accredited UCAP Capacity	Capacity to Match Amos / Mountaineer UCAP
50% of Amos and Mountaineer	2,100	91%	1,907	
Wind	2,100	11%	231	17,336
Solar (Tracking)	2,100	39%	819	4,890
Storage - 4 hour	2,100	70%	1,470	2,724
Solar Plus 4 hour Storage	2,100	72%	1,512	2,649
Gas CT or CC	2,100	96%	2,016	1,986

III. RESOURCE COST ASSUMPTIONS

Q. WHAT IS THE COST OF SERVICE OF THE ELG COMPLIANCE INVESTMENTS?

A. Virginia's share of the ELG investments at the Plants is approximately $98 million. The annual revenue requirement (depreciation and return on investment) that Virginia customers would pay is $15 million in the year the ELG investments go in service. This assumes the depreciation rates approved by the Commission in the 2021 R-RAC proceeding for the CCR investments are also adopted for the ELG investments. This will drop to $2 million per year for Mountaineer in 2034, as the Amos ELG is assumed to be fully depreciated in 2033. Over the full period between 2022 and 2040 I would estimate the Virginia share of the nominal revenue requirement will be

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approximately $150 million. The present value of this cost of service will be approximately $93 million. I included these values in the incremental ongoing cost of operating the Plants.

Q. WHAT ASSUMPTIONS DID YOU MAKE ABOUT FUTURE INCREMENTAL CAPITAL COSTS OF THE PLANTS?

A. In both cases, all of the ongoing capital expense forecasts, excluding the ELG costs, were included through 2035. From 2036 to 2040, I used a "glide path" capital expense forecast, which reduced that maintenance capital in those years. I applied a levelized carrying charge to that capital expense starting in 2029 in order to determine what the cost of service savings would be by avoiding that capital.

Q. WHAT ASSUMPTIONS DID YOU MAKE REGARDING THE FUTURE OPERATIONS AND MAINTENANCE COSTS OF THE PLANTS?

A. The analysis assumed that the currently forecasted level of O&M through 2030. In years after that, O&M was projected to decline, commensurate with expected lower capacity factors if a national carbon tax is enacted. Reduced capacity factors would mean less maintenance and waste disposal costs, and thus O&M was assumed to be 75% of the 2030 forecast between 2031 and 2040. All of the fixed O&M was assumed to be avoidable starting in 2029.

I also prepared a forecast of taxes that could be avoided if Virginia customers were no longer benefitting from the Plants, including property taxes and a tax levied on generating plants in West Virginia called the Business & Occupation (B&O) tax. APCo is expected to pay about $10 million per year in property taxes and about $36

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million annual in B&O tax towards the end of this decade. Virginia's half of these two taxes is expected to be about $23 million annually in 2028 and beyond.

Q. HOW WERE THE COSTS OF THE REPLACEMENT RESOURCES COMPUTED?

A. I used a spreadsheet model to compute a forecast of the annual revenue requirement on the new resource additions using customary ratemaking principles. For the owned resources, this included forecasting rate base declining over time, return on rate base at a weighted average cost of capital, depreciation, O&M, production tax credits over the first 10 years on the wind assets, and normalization of the investment tax credits on the solar assets over the 35 year lifetimes. I used the PPA costs for those resources.

Q. WHAT WERE THE SOURCES OF THE COST OF REPLACEMENT RESOURCES?

A. I used the actual resource costs for the portion of replacement capacity provided by the Virginia half of the 498 MW of the currently proposed VCEA compliant projects which are currently pending before the Commission in Case No. PUR-2021-00206. The gross cost of service of the 498 MW is projected to average about $42 million per year for Virginia customers through 2040. Those resources are summarized here in Table 5.

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TABLE 5 – Near Term Planned Resources					
Facility	**Nameplate Capacity MW**	**Owned / PPA**	**State**	**Resource Type**	**Operation**
Firefly	150.0	Owned	Virginia	Solar	July 2024-June 2059
Amherst*	4.9	Owned	Virginia	Solar	Jan 2023 - Dec 2057
Horsepen	20.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Dogwood*	18.9	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Sun Ridge	50.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Virginia Domiciled	**243.8**				
Top Hat	204.0	Owned	Illinois	Wind	Jan 2025 - Dec 2054
Bedington	50.0	Owned	West Virginia	Solar	Oct 2023 - Sep 2058
TOTAL	**498**				

*Distribution Resource

The remaining generic resource costs, including construction cost and fixed O&M for owned resources and PPA costs, were sourced as described in section 4 of the VCEA Report. The generic wind and solar resource costs were aligned with the average of the bids received by APCo in the RFPs it issued for both owned and PPA resources in 2021. All new wind and solar resource costs are based on actual market information available at the time the analysis was performed.

Q. HOW MUCH WIND AND SOLAR WOULD BE REQUIRED TO REPLACE THE PLANTS, AND WHAT WOULD IT COST, IF ALL OTHER RESOURCE TYPES WERE EXCLUDED?

A. The proposed portfolio in the 2021 VCEA Filing of 204 MW of wind and 294 MW of solar is projected to provide a total of 108 MW of UCAP capacity in 2028. Based on current ELCC capacity credit expectations (as illustrated in Table 4), it would take 17.7 times that amount of wind and solar to replace Virginia's half of the Plants'

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1,907 MW of UCAP: that equals 8,800 MW of resources needed by 2028. Based on the actual costs of these resources, replacing the Plants with this mix of 40% wind and 60% solar would cost close to $15 billion. An investment of this size in such a short period of time would be unprecedented in scope and scale for APCo, especially given the uncertainty around whether siting, constructing, and financing such a portfolio is achievable.

This group of seven proposed new resources selected from the 2021 RFP's amounting to 498 MW is projected to cost roughly $19 million per year on average through 2040 after deducting the expected energy revenue that will reduce customer fuel costs. As it would take 17.7 times this amount of resources to replace the UCAP of these plants, such a mix of wind and solar would equate to about $338 million per year in annual average net cost of service through 2040, which would be four times the incremental cost of the Plants over that period.

Q. HOW MUCH DO APCO'S NEW RESOURCES COST PER MEGAWATT-HOUR OF ENERGY?

A. When the projected annual revenue requirements of the ten new assets, net of tax credits, are divided by the energy they are expected to produce, the average cost to customers per MWh over the 17 years between 2024 and 2040 is expected to be $53/MWh. The lowest cost year in that period is projected to be $47/MWh.

The ten new assets are: the seven resources obtained through the 2021 RFPs set out in Table 5, plus three other PPA resources that went online in 2021 or that will go online in 2022: the 20 MW Wytheville, 20 MW Leatherwood, and the 15 MW

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Depot solar facilities. A diverse portfolio such as this would be representative of what APCo would expect if it sought a large amount of renewable capacity needed to replace some or all of the Plants' capacity (assuming it could even find and get approval for that amount of capacity by 2028, which is doubtful).

Q. DOES RENEWABLE ENERGY CERTIFICATE VALUE INFLUENCE NEW RESOURCE COSTS, INCLUDING PPA COSTS?

A. Yes, and the magnitude of that influence is growing of late. All of these ten renewable assets come with renewable energy certificates (RECs), which have cash value in REC trading markets in addition to the value of the energy itself. PJM Tier 1 RECs traded as high as $24.50/MWh in January 2022. In the two VCEA portfolios on which I based my analysis in this proceeding, RECs were assumed to be priced at between $27 and $32 per MWh between 2023 and 2031 (VCEA Report Figure 8).

In recent years, many PJM states and neighboring states in the Northeast have established renewable energy mandates, and corporations are making substantial renewable energy pledges. This has created high demand for renewables and their RECs, which has led to difficulty getting resources sited, interconnected, approved, and built in time to meet growing compliance targets. In February 2022, PJM publicly acknowledged the backlog it is facing in getting new projects moved through the interconnection queue, and announced it was seeking to implement a two-year moratorium on new interconnection requests. All of the above has driven up REC prices and PPA prices.

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APCo has a requirement to either self-generate or purchase and retire RECs in order to comply with the VCEA, and thus RECs are required by APCo when it seeks new resources. For the PPA assets, this REC value can push up the PPA price to an amount well above the cost the developer incurs to build and operate the assets themselves. RECs are separately priced in some renewable PPAs, and buried in a combined energy/REC price in others, so it isn't always clear what the REC value is, but it's clearly a factor developers consider in pricing assets offered into RFPs for both owned assets and PPAs. Either way, the REC value that rational profit seeking developers attempt to capture in pricing their product will cause the price of new resources to be higher than the cost of asset itself.

IV. IMPACTS OF THE VCEA ON THE PLANTS

Q. DOES THE VCEA REQUIRE THE PLANTS TO RETIRE?

A. No. The Plants are located outside of Virginia, and thus are not required to be retired by any certain date by the VCEA.

Q. WHAT IMPACT DO THE VCEA'S NEW RESOURCE PETITION REQUIREMENTS HAVE ON THE ANALYSIS OF THE ECONOMICS OF THE ELG INVESTMENT AND THE PLANTS' CONTINUED OPERATIONS?

A. The VCEA resource petition mandates have very little impact on an evaluation of the ELG investment, or the need for the Plants in general. The law states that APCo must meet RPS requirements and petition the Commission for approval of certain resources. The petition requirements that are applicable in time to impact the ELG decision are 400 MW of wind or solar by 2027 and 25 MW of storage by 2025. The

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next interim petition requirement after the 2027 requirement is 200 additional MW of wind or solar by 2030 and 125 additional MW of storage by 2030. Any resources added for VCEA compliance after the 2027 requirement would be irrelevant to the decision regarding how to replace the Plants' capacity, as that decision would have already been made.

Table 21 in the VCEA Report shows the UCAP provided by the additions that APCo plans to add to achieve VCEA compliance through 2040. In that VCEA portfolio, only the minimum resources needed for VCEA compliance (assuming they are cheaper than RECs) were added. The Company is not projected to need capacity to maintain compliance with the PJM capacity requirement until 2040. That resource plan included an assumed amount of distributed generation (labeled New DG) built on the APCo system, which is not mandated by the VCEA. As shown in the 2028 column on the line labeled Total Additions (Firm and Degraded), the total UCAP added by 2028 from all resources is expected to be 298 MW, which is less than half of the UCAP capacity of the smallest unit at Amos, which is 742 MW. Looking further out, it takes until 2035 for the total UCAP of all resources planned for VCEA compliance to total more than 742 MW. This demonstrates that capacity provided by the new resources planned for VCEA compliance are less than the amount of capacity needed to offset even the smallest unit of the Plants until 13 years from now.

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Q. DO THE VCEA'S RENEWABLE ENERGY REQUIREMENTS HAVE AN IMPACT ON THE ANALYSIS OF THE ECONOMICS OF THE ELG INVESTMENT, OR THE VALUE OF THE PLANTS IN GENERAL?

A. The economics of the Plants are impacted by the VCEA requirements as reflected in the Company's Fundamental forecasts, which assume a full build-out of VCEA resources in PJM and Virginia's participation in RGGI. Regarding APCo specifically, the renewable energy targets in the VCEA mandate that a percentage of the Company's Virginia jurisdictional energy load be met from qualifying resources or RECs. That percentage increases through time before reaching 100% by 2050. As the requirement is a percentage of load, not a percentage of energy generated by the Company's resources, the law does not restrict how much the Plants can run. As long as the Company has enough of a combination of REC purchases and qualifying renewable generation to meet the percent of Virginia load targets, the Company will be in compliance, regardless of how much or how little its fossil plants run. Even if the VCEA compliance requirement was qualifying energy or RECs of 100% of Virginia load at some point before the Plants retire, any generation produced by the Plants will be sold off-system into the PJM market, generating value for customers despite not being needed to serve internal load.

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V. TRANSMISSION CONSIDERATIONS

Q. COULD RETIREMENT OF THE PLANTS CREATE THE NEED TO INVEST IN THE BULK HIGH VOLTAGE TRANSMISSION SYSTEM?

A. Yes. AEP's transmission planning organization performed high level studies while the Company was initially evaluating whether to make the CCR and ELG investments at the Plants. Those studies indicated that retiring the Plants in 2028 could result in the need for between $100-$200 million of upgrades to the high voltage transmission system to prevent violations to both thermal and voltage reliability standards. This was factored into the economic analysis that supported making the investments.

Q. DID YOU INCLUDE POTENTIAL TRANSMISSION COSTS IN THE ANALYSIS SUPPORTING THIS PETITION?

A. No, I did not include transmission costs in this analysis because the Plants will not be retiring in 2028. I also did not include an assumption of interconnection costs in the cost of the replacement assets, beyond routine interconnection costs assumed in the generic resources. Based on the interconnection costs of adding the 498 MW of resources currently under development, the costs of getting enough transmission for the thousands of nameplate MW needed to replace Virginia's half of the Plants could be $50-$100 million depending on the locations of replacement capacity. This would raise the costs of replacing the Plants above what I have presented here.

VI. CLINCH RIVER RGGI COMPLIANCE

Q. PLEASE DESCRIBE THE RGGI COMPLIANCE COSTS RELATED TO THE CLINCH RIVER PLANT.

A. Clinch River is located in Virginia, and thus is subject to RGGI compliance costs due to Virginia's participation in RGGI. As discussed in her testimony, Company witness Castle has included an estimate of these compliance costs in his calculation of the revenue requirement of the E-RAC rider. These costs have been deferred (not collected from customers) to date. As a generator located in PJM, Clinch River only dispatches when it is economic compared to the other resources that have been offered into PJM to meet load in a given hour. When APCo offers the unit for sale into the PJM energy market, the offered price includes the cost of any RGGI allowances that APCo would need to purchase to allow Clinch River to run. PJM would only dispatch Clinch if its offer price was lower than the marginal energy price. As a result, any RGGI-related costs are offset by energy revenues received when the energy is sold. Customers have already received the fuel cost of service reduction from these revenues, and therefore it is appropriate for APCo to recover those costs in the E-RAC revenue requirement.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APCo Exhibit No. ___
Witness: JFM
Schedule 1

AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY

American Electric Power
1051 E Cary Street, Suite 1100
Richmond, Virginia 23219
AEP.com

January 7, 2022

By Electronic Filing

Hon. Bernard J. Logan, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street
Richmond, Virginia 23219

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Re: Petition of Appalachian Power Company
For approval of its 2021 RPS Plan
under § 56-585.5 of the Code of Virginia
and related requests
Case No. PUR-2021-00206

Dear Mr. Logan:

Enclosed for filing is Corrected Attachment 1, the 2021 RPS Plan, to the Petition that was filed in the above-referenced case on December 30, 2021. After the filing of the 2021 RPS Plan, the Company noted that Tables 22 and 23 contained incorrect information, which has been corrected in this version. In addition, the Plan's original Appendix B had two tables numbered 29, which has also been corrected and all tables past Table 29 have been renumbered. Lastly, the information in Appendix C has been removed, as it was inadvertently included in the report.

Sincerely,

Noelle J. Coates

Enclosure

cc: William H. Chambliss, Esq.
Kiva B. Pierce, Esq.
C. Meade Browder, Jr., Esq.

APCo Exhibit No. ___
Witness: JFM
Schedule 1

2021-00206
12/30/2021

APPALACHIAN POWER

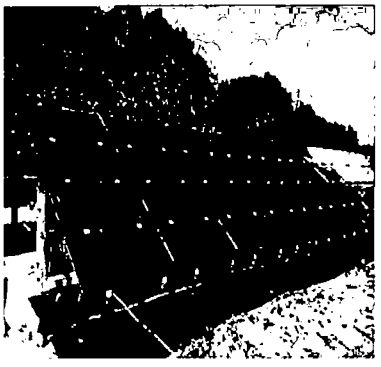
An AEP Company

BOUNDLESS ENERGY

RENEWABLE PORTFOLIO STANDARD PLAN

CASE NO. PUR-2021-00206

December 30, 2021



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1.0 Virginia Clean Economy Act Compliance Plan Overview

Consistent with the requirements of Virginia Code Section 56.585.5.D.4, Appalachian Power Company (Appalachian, APCo, or the Company) submits the second of its annual plans to meet the requirements in the Virginia Clean Economy Act (VCEA).

This year's report includes six separate VCEA compliant plans for informational purposes. Descriptions of the six Portfolios are provided in Table 1. Four of the plans, Portfolios 1-4, assume only the minimum level of renewable resources needed to meet the annual VCEA energy targets are added. These plans were prepared under varying scenarios in which the Company's two coal plants were retired in either 2028 or 2040, and replaced with either a combination of renewable and gas fired resources or 100% renewable resources. The fifth plan (Portfolio 5) was prepared under the assumption that 1,000 MW of additional wind above the minimum VCEA requirements is available and can be added based on favorable economics in time to capture production tax credits before they expire in 2026. The sixth plan (Portfolio 6) is a sensitivity case prepared as a result of a requirement in the Commission's order on the Company's 2020 VCEA filing,[1] in which future wind resources are assumed to have a capacity factor that is consistent with the Company's current wind PPA resources.

TABLE 1: PORTFOLIO DESCRIPTIONS

Portfolios					
1	**2**	**3**	**4**	**5**	**6**
RGGI Only CO2 2040 AM & MNTR Ret. Gas Options Available	RGGI to $15 CO2 2040 AM & MNTR Ret. No Gas Option Available	RGGI Only CO2 2028 AM & MNTR Ret. Gas Options Available	RGGI to $15 CO2 2028 AM & MNTR Ret. No Gas Option Available	RGGI to $15 CO2 2040 AM & MNTR Ret. No Gas Option Available Higher Wind Limits	RGGI to $15 CO2 2040 AM & MNTR Ret. No Gas Option Available Current Wind Project Cap Factors

For the purposes of this report, the Company's base case assumption is that the coal plants will operate through 2040 and fossil fueled resources will not be used to replace them at that time. Portfolio 2 presents that scenario and will be referred to in this report as the VCEA Plan or the Plan. Nevertheless, APCo intends to issue Request for Proposals (RFPs) in the near

[1] Final Order at 5, *Commonwealth of Virginia, ex rel. State Corporation Commission Ex Parte: Establishing 2020 RPS Proceeding for Appalachian Power Company*, Case No. PUR-2020-00135, Doc. Con. Cen. No. 210440238 (April 30, 2021) ("Order on 2020 Filing").

term based on Portfolio 5, and seek approval of those resources based on the results of APCo's economic analyses. The Company's 2021 VCEA Plan includes a geographically varied portfolio of storage, solar and wind resources, both Company and third party owned, as well as market REC purchases. In the filing associated with this Plan, the Company is seeking a prudency determination of the acquisition of one 150 MW solar facility and the agreements to purchase the output of three solar facilities via power purchase agreements (PPAs) totaling approximately 89 MW; approval to recover the costs of 50 MW of owned West Virginia solar and 204 MW of Illinois wind resources. In addition, APCo is seeking cost recovery for RECs associated with 40 MW of Virginia solar contracted through its Cogen/SPP rate schedule; 15 MW of contracted solar located in Virginia; 5 MW owned solar in Virginia; as well as market REC purchases necessary for annual compliance.

The Company developed these VCEA compliant plans in a way that is similar to how Integrated Resource Plans are developed, using the same general methods, commodity price forecasts, optimization software, load forecasts, and resource cost assumptions. The amount and timing of the resource additions were determined with Plexos® optimization software, adjusted as needed to include resource additions that were necessary to meet certain annual requirements associated with energy efficiency targets and Virginia-domiciled renewable and storage.

In addition to determining the type and timing of resource additions, this report provides an estimate for the rate impacts associated with compliance, consistent with the Commission's requirement in the Order on the 2020 Filing.

1.1 VCEA Expected Resource Additions

APCo issued a series of RFPs for renewable resources and RECs in 2021 to meet the VCEA requirements and is seeking approval in both Virginia and West Virginia for several projects that resulted from that process. It is assumed for purposes of this Plan that both Virginia and West Virginia commissions will approve those investments and that each retail jurisdiction will receive its allocated share of costs and attributes. All other identified renewable resource additions are assumed to accrue exclusively to Virginia retail customers.

In the short term, APCo expects to acquire or contract for 498 MW of resources. These specific resources, which are the subject of the petition filed simultaneously with this report, are shown in Table 2.

TABLE 2 APCO PLANNED NEAR-TERM RESOURCE ADDITIONS

Facility	Nameplate Capacity MW	Owned / PPA	State	Resource Type	Operation
Firefly	150.0	Owned	Virginia	Solar	July 2024-June 2059
Amherst*	4.9	Owned	Virginia	Solar	Jan 2023 - Dec 2057
Horsepen	20.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Dogwood*	18.9	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Sun Ridge	50.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Virginia Domiciled	**243.8**				
Top Hat	204.0	Owned	Illinois	Wind	Jan 2025 - Dec 2054
Bedington	50.0	Owned	West Virginia	Solar	Oct 2023 - Sep 2058
TOTAL	**498**				

*Distribution Resource

In addition, the Company expects the Depot (15 MW) and Wytheville (20 MW) solar facilities to be operational in late 2021-early 2022. The Leatherwood (20 MW) solar facility was placed in-service in September 2021. All of the renewable attributes of the Leatherwood and Wytheville facilities, which are PURPA projects, are being attributed to Virginia. Finally, the Company is proposing to add approximately 8 MW of energy storage for the purposes of improving reliability along its Glade Station – White Top circuit.

The RFP issued for RECs in May 2021 resulted in one bid. The Company elected not to pursue this bid based on its economic analysis, and will continue to issue RFPs for RECs from time to time to evaluate the cost effectiveness and level of availability of REC contracts as a compliance option.

As shown in Table 3 below, the Company will satisfy the 2023 interim wind and solar requirements of Section 56-585.5 D.1 by petitioning the Commission for approval to acquire approximately 155 MW of owned Virginia-domiciled solar facilities (Firefly and Amherst), and approximately 144 MW of contracted, third-party owned, Virginia-domiciled solar facilities (Wytheville, Leatherwood, Depot, Horsepen, Sun Ridge, and Dogwood). Progress towards the Virginia-domiciled resources that will be used for compliance with the 2023 petition requirement are listed in Table 3.

TABLE 3: APCO PROGRESS TOWARDS 56-585.5 D. WIND/SOLAR REQUIREMENTS

56-585.5.D Requirement	PPA	Owned	Total
YE 2023	70	130	200
YE 2027	140	260	400
YE 2030	210	390	600
2021 Plan	144	155	299

The VCEA section 56-585.5 E also contains interim storage resource requirements. See Table 4 for the Company's Progress towards these requirements. The Company expects to solicit bids for qualifying storage resources in a future RFP in 2022.

TABLE 4: APCO PROGRESS TOWARDS 56-585.5 E. STORAGE REQUIREMENTS

56-585.5.E Requirement	PPA	Owned	Total
YE 2025	9	16	25
YE 2030	53	98	150
YE 2035	140	260	400
2021 Plan	0	0	0

1.2 Virginia Clean Economy Act Near-Term Compliance

The Company met the RPS requirements of Section 56-585.5 C for 2021 largely with its current supply of renewable resources. In Table 5, the Company has prepared a projection of its expected position in terms of VCEA qualifying energy production versus each year's energy targets through 2025. Given the assumed production of the existing and planned energy resources, the Company projects a deficit in each year. It is anticipated this deficit will be addressed through the tactical purchase of RECs, when market conditions are favorable.

TABLE 5: APCO NEAR TERM VCEA ENERGY COMPLIANCE

Projected REC production and forecast requirments (MWh)

	2021	2022	2023	2024	2025
Current Resources					
Hydro - owned	478,739	478,739	478,739	478,739	478,739
Hydro (PPA)	70,366	70,366	70,366	70,366	70,366
Bluff Point Wind (PPA)	189,720	189,720	189,720	189,720	189,720
Camp Grove Wind (PPA)	99,893	99,893	99,893	99,893	99,893
Fowler Ridge (PPA)	114,235	114,235	114,235	114,235	114,235
Leatherwood (PPA)	13,039	45,153	44,927	44,703	44,479
Sub-total Current Resources	965,993	998,107	997,881	997,656	997,433
Projected Resources					
Wytheville (PPA)	0	42,968	42,753	42,539	42,327
Depot (PPA)	0	13,285	15,475	15,398	15,321
Amherst - owned	0	314	5,290	5,264	5,237
Horsepen (PPA)					21,765
Dogwood (PPA)					16,446
Sun Ridge (PPA)					58,200
Top Hat - owned					381,979
Firefly - owned				111,428	167,142
Bedington - owned			10,962	52,225	51,964
Subtotal - Projected Resources	0	56,567	74,481	226,854	760,381
Total - Current and Projected	965,993	1,054,674	1,072,361	1,224,510	1,757,814
less APCo Renewable Riders	(80,342)	(80,342)	(80,342)	(80,342)	(80,342)
Production Available for Compliance	885,651	974,332	992,019	1,144,168	1,677,472
Virginia Retail Load (forecast)(MWh)	15,040,556	15,017,019	15,002,519	14,989,673	14,998,772
RPS % Requirement	6%	7%	8%	10%	14%
RPS REC Requirement	902,433	1,051,191	1,200,202	1,498,967	2,099,828
REC Deficit	(16,783)	(76,859)	(208,182)	(354,799)	(422,356)
Cumulative REC Surplus/(Deficit)		(93,642)	(301,824)	(656,623)	(1,078,979)

Embedded Jurisdictional Split	0.501
New Asset Split	0.501

	2021	2022	2023	2024	2025
Requirement	902,433	1,051,191	1,200,202	1,498,967	2,099,828
WV Approves	871,923	953,166	959,959	1,002,627	1,657,979
Only Virgina Approves	965,993	1,054,674	1,072,361	1,224,510	1,757,814

1.3 APCo's Coal Units

The Company is required to make certain environmental investments in its two coal plants (2,930 MW Amos, St. Albans, WV; 1,336 MW Mountaineer, New Haven, WV) in order for them to operate past 2028. In Case No. PUR-2020-00258, the Virginia SCC did not approve cost recovery for the Virginia jurisdictional share of the investment necessary to comply with the Effluent Limitation Guidelines (ELG) rule. As a result, the Company modeled two sets of scenarios: one with the two plants retiring at the end of 2028 and one with the plants retiring in 2040. During the performance of the analyses in this report, the Public Service Commission of West Virginia (WVPSC) ordered (Case No. 20-1040-E-CN) APCo to proceed with the investments necessary to keep the plants operational past 2028 and held that West Virginia customers will, if necessary, pay for the entire investment. There are unresolved issues associated with the sharing of capacity and energy benefits of these plants between the states if the Virginia SCC ultimately denies cost recovery of the ELG investment and the coal plants remain operational past 2028. For the purposes of discussion of the VCEA Plan (Portfolio 2) in this report, it is assumed that Virginia will continue to have the benefit of the two coal plants through 2040.

1.4 Environmental Justice

Appalachian is committed to the tenets of the Commonwealth's Policy on Environmental Justice and considers it in all prospective transactions for renewable resources. Identification and remediation of potential concerns are made during the RFP process, as discussed in the petition. Because Environmental Justice is specific to the communities immediately surrounding resources, meaningful screening can only be accomplished once potential sites have been identified. The Plexos® selected resource additions identified in this Plan are generic in nature and are not site specific and thus cannot be evaluated for potential Environmental Justice issues.

1.5 Reliability Impacts

Through Plexos®, the Company models reliability at a system level by ensuring that sufficient resources are available to meet customer load based on the hourly profile of both load and resources. Because the Company is a member of PJM, Plexos® has the option to fill energy deficits in any specific hour with market purchases. At this time, the Company expects that supply of energy from PJM will be available through at least 2030 when needed with pricing

based upon scarcity. The Company will continue to evaluate and identify potential reliability concerns and mitigation as renewable penetration increases in APCo's service territory, Virginia, and PJM.

2.0 VCEA Summary

In 2020, the General Assembly passed the VCEA, which was signed into law by Governor Northam. The VCEA is a transformative law that seeks to end carbon dioxide emissions from the electric utility industry in Virginia.[2]

2.1 VCEA Requirements

There are four primary requirements of the VCEA related to resource acquisition:

1. Annual RPS requirement. For APCo, this requirement is reproduced in Table 6 and begins at 6% in 2021 and escalates to 100% by 2050.

TABLE 6: APCO VCEA RPS REQUIREMENTS BY YEAR

Year	APCo RPS Requirement (%)	Year	APCo RPS Requirement (%)
2021	6	2036	53
2022	7	2037	53
2023	8	2038	57
2024	10	2039	61
2025	14	2040	65
2026	17	2041	68
2027	20	2042	71
2028	24	2043	74
2029	27	2044	77
2030	30	2045	80
2031	33	2046	84
2032	36	2047	88
2033	39	2048	92
2034	42	2049	96
2035	45	2050 and thereafter	100%

2. Development of Virginia domiciled solar and wind resources. APCo is required to petition the Commission for 600 MW solar or wind resources by December 31, 2030, with interim targets beginning December 31, 2023; 35% of those resources are required to be contracted via PPA. The Company is using nameplate capacity to determine compliance with these requirements.

[2] Appalachian is a "Phase I" utility as defined in Section 56.585.1. A.1. of the Code of Virginia. As such, this report will refer to the requirements in the VCEA that only apply to Appalachian.

3. Development of Energy Storage resources. By December 31, 2035, the VCEA requires APCo to have petitioned the Commission for necessary approvals to construct or acquire 400 MW of energy storage capacity, or more with Commission approval. These resources must meet the same 35% PPA requirement that applies to the Virginia domiciled solar and wind resources. Further, 10% of the battery installations are required to be behind the meter (BTM) installations.

   The Commission opened Case No. PUR-2020-00120 to establish rules and regulations for the required addition of storage and subsequently issued regulations to determine the appropriate timing of storage additions on December 18, 2020. The Company is working to identify the preferred location and size of storage resources, and will issue an RFP in 2022 for storage resources. See Table 7 for those interim storage addition minimums[3].

TABLE 7: VCEA REQUIRED STORAGE ADDITIONS

Date	New Storage Additions (MW)	Cumulative Storage Additions (MW)
12-31-2025	25	25
12-31-2030	125	150
12-31-2035	250	400

4. Energy Efficiency requirement. APCo must implement energy efficiency measures that achieve energy savings equivalent to at least 2% of the Company's 2019 retail sales by 2025. The VCEA also specifies that the Commission shall establish new EE requirements for the period of 2026 to 2028, and for every three year period thereafter. Due to the uncertain nature of any future proceeding regarding the efficacy or cost-effectiveness of additional EE, the amount of EE requirements set by the Commission was assumed to remain constant beyond 2025, with any additional EE in future years only being selected for economic purposes.

[3] Order for Notice and Comment, *Commonwealth of Virginia, ex rel., State Corporation Commission Ex Parte: In the matter of establishing rules and regulations pursuant to §56-585.5 E 5 of the Code of Virginia related to the deployment of energy storage*, Case No. PUR-2020-00120, Doc. Con. Cen. No. 200910238 (Sept. 11, 2020).

2.1.1 Commission Filing Requirements

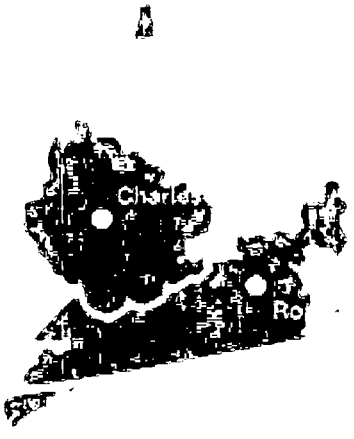
In the Attachment to its July 10, 2020 *Order Establishing 2020 RPS Proceedings*, the Commission set forth certain filing requirements. In addition, in the Order on the 2020 Filing, the Commission imposed certain requirements for this 2021 VCEA filing. The requirements of each of these orders, along with a description of where they are addressed in this report, are contained in Appendix E.

3.0 APCo Company Summary and Assumptions Overview

3.1 Overview of APCo

APCo's customers are retail and sales-for-resale (wholesale) customers located in the states of Virginia, West Virginia and Tennessee (see Figure 1). Currently, APCo serves nearly 1 million customers, with nearly 540,000 of those customers being in Virginia. The peak load requirement of APCo's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. APCo's all-time highest recorded peak demand was 8,708 MW, which occurred in February 2015, and the highest recorded summer peak was 6,755 MW, which occurred in August 2007. The most recent (summer 2021 and winter 2020/21) actual APCo summer and winter peak demands were 5,348 MW and 5,975 MW, occurring on August 24, 2021 and February 8, 2021, respectively.

FIGURE 1: APCO'S SERVICE TERRITORY



3.2 APCo's existing resources

APCo serves its customers through owned generation resources and PPAs for renewable resources. See Table 8 and Table 9 for a summary of these owned and contracted resources, respectively.

TABLE 8: APCO OWNED GENERATION RESOURCES

Plant	Capacity [MW[1]]	No. of Units	Location	Fuel	First Unit Commissioned	Retirement Date
John E. Amos	2930	3	Winfield, WV	Coal	1971	2040*
Mountaineer	1305	1	New Haven, WV	Coal	1980	2040
Ceredo	450	6	Ceredo, WV	Natural Gas	2001	2041
Clinch River	455	2	Carbo, VA	Natural Gas	1958	2025
Dresden	570	3	Dresden, OH	Natural Gas	2012	2047
Buck	1.5	3	Ivanhoe, VA	Hydro	1912	2024
Byllesby	4.2	4	Byllesby, VA	Hydro	1912	2024
Claytor	75.5	4	Radford, VA	Hydro	1939	2041
Leesville	50	2	Leesville, VA	Hydro	1964	2040
London	6.5	3	Montgomery, WV	Hydro	1935	2044
Marmet	5.8	3	Marmet, WV	Hydro	1935	2044
Niagara	2.4	2	Roanoke, VA	Hydro	1906	2024
Smith Mountain	585	5	Penhook, VA	Hydro	1965	2040
Winfield	10	3	Winfield, WV	Hydro	1938	2044
TOTAL	**1310.9**	**32**				

[1] Nameplate rating. For capacity planning purposes, PJM UCAP ratings are used.

*Retirement date for planning purposes. May differ from retirement dates for depreciation purposes

TABLE 9: APCO CONTRACTED GENERATION RESOURCES

Facility	Nameplate Capacity MW	State	Resource Type	Contract Expiration
Ohio Valley Electric Corporation	332	Ohio	Coal	2040
Summersville I and II	80	West Virginia	Hydro	2027
Bluff Point	120	Indiana	Wind	2037
Camp Grove	75	Illinois	Wind	2028
Beech Ridge	101	West Virginia	Wind	2030
Fowler Ridge III	99	Indiana	Wind	2029
Grand Ridge II and III	101	Illinois	Wind	2029
Depot Solar	15	Virginia	Solar	2041
Wytheville*	20	Virginia	Solar	2036
Leatherwood*	20	Virginia	Solar	2036
TOTAL	**963**			
*Behind the Meter Resources				

3.3 Key Modeling Assumptions

Key assumptions included in the VCEA Plan

1. Appalachian Power operates in both Virginia and West Virginia and is subject to regulation in both states, with resource acquisition determinations made by regulators

in both states and resource costs allocated between the jurisdictions. The Company assumes, for the purposes of this Plan, that all of the specific resources in Table 4 will be approved by both Virginia and West Virginia. Subsequent renewable resources will accrue entirely to Virginia retail customers. There is not currently a renewable portfolio standard in place in West Virginia.

2. The Company's base case assumption is that Amos and Mountaineer coal-fired plants will run through 2040 consistent with the WVPSC's order in Case No. 20-1040-E-CN. After 2040, the Company has assumed, in the VCEA Plan, that capacity shortfalls will be met with a combination of renewable generators and energy storage. In other cases where the Company modeled fossil additions for informational purposes, it is understood that those resources would necessarily be located outside of Virginia.
3. The Company will sell the REC bank that it accumulated through the end of the Voluntary RPS in 2020 during 2021 for the benefit of customers that were subject to the voluntary RPS. As a consequence, the Company's starting REC position for the VCEA is zero.
4. RECs were made available to the Plexos® model as a resource option that could be selected if they were a less costly VCEA compliance option than other renewable resources, based on an assumed REC price curve. Projected RECs in excess of any one year's VCEA energy requirement were assumed to be sold the following year in order to reduce overall compliance costs.
5. Any capacity additions resulting in excess capacity above the Company's minimum PJM UCAP capacity requirement were modeled to be sold to either the PJM capacity market or to a third party under a bilateral purchased power agreement beginning in 2026, at the Company's fundamental PJM capacity price forecast.
6. The Company's existing renewable resources are contributing to the VCEA renewable energy goals. Existing renewable resources are allocated based on the ratio of APCo Virginia retail load (including Public Authority and Commonwealth customers) to total company load, which is estimated to be 50.1%. Existing contracts are modeled as ending on their expiration date and are not expected to be renewed.

3.4 APCo Load Forecast

The APCo load forecast was developed by the American Electric Power Service Corporation (AEPSC) Economic Forecasting organization and completed in June 2021.[4] The load forecast is the culmination of a series of underlying forecasts that build upon each other. The economic forecast provided by Moody's Analytics is used to develop the customer forecast,

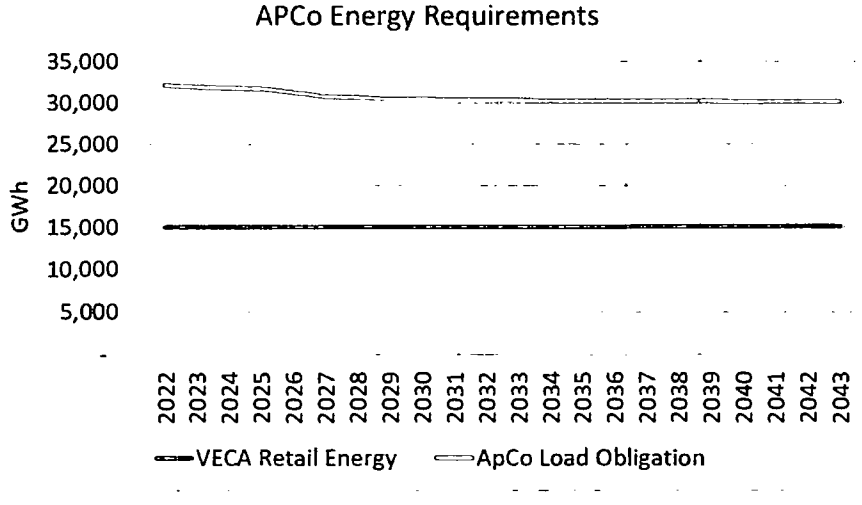
[4] The load forecasts (as well as the historical loads) integral to this Plan reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load*, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

which is then used to develop the sales forecast, which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 15-year period (2022-2036),[5] APCo's service territory is expected to see population to decline at 0.3% per year and non-farm employment growth 0.3% per year, and APCo is projected to see its customer count decline by 0.1% over this period. Over the same forecast period, APCo's retail sales are projected to decline at 0.2% per year, with growth expected from the industrial class (+0.2% per year) while the residential class is projected to decline at a compounded annual growth rate (CAGR) of 0.4% per year. Finally, APCo's internal energy is expected to decline by 0.4% per year and peak demand is expected to decline by 0.6% per year through 2036. For this forecast, it has been assumed that APCo's current wholesale customers will not renew their contracts beyond the current contract expiration dates, resulting in removal of their load from the forecast.

Figure 2 shows both the total load forecast for APCo and the Virginia retail sales applicable to the VCEA. The Company understands "retail" as defined in the Code to include the Public Authority and Commonwealth customers in Virginia, for the purposes of determining VCEA RPS requirements. These forecasted retail sales along with the annual VCEA energy targets provided a key input into the development of the proposed VCEA Plan.

FIGURE 2: APCO ENERGY REQUIREMENTS



3.5 The Fundamentals Forecast

The Fundamentals Forecast is a long-term, weather-normalized commodity market forecast principally based upon the assumptions contained in the Energy Information Administration's Annual Energy Outlook (AEO). It is provided to AEPSC and all AEP operating companies for purposes such as resource planning, capital improvement analyses, fixed asset impairment accounting, and others. These projections cover the electricity market within the Eastern Interconnect, the Electric Reliability Council of Texas, and the Western Electricity Coordinating Council. The Fundamentals Forecast includes, among other factors: 1) hourly, monthly and annual regional power prices (in both nominal and real dollars); 2) prices for various qualities of coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) SO_2, NO_x, and CO_2 burden values; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors; 10) VCEA compliance for Virginia utilities among others.

Table 10 below describes the Fundamentals Forecast components, which are sourced directly from the EIA AEO, from third party energy consultancies, or were sourced internally. As the EIA AEO does not provide the granularity for most regulatory applications, the Aurora energy market simulation model was utilized to create a reasonable proxy for the EIA AEO while providing the level of detail necessary for downstream consumption.

TABLE 10: FUNDAMENTALS FORECAST COMPONENTS

Forecast Components	EIA	Other	Source
Economy; Inflation/GDP deflators	✓		EIA Reference case
Generating Reserve Margins		✓	RTO Requirements
Electric Load		✓	AEP Load Forecasting
Electric Load shapes		✓	AEP Fundamentals
Solar/Wind production shapes by area		✓	NREL
Coal; Delivered price to EIA regions	✓	✓	EIA Reference case FOB prices + AEP Fundamentals
Natural gas price; Henry Hub	✓		EIA Reference case
Natural gas price; Locational values	✓	✓	EIA Reference case - Henry Hub + AEP Fundamentals
Natural gas supply; Lower 48 production	✓		EIA Reference case
Natural gas demand (incl. losses)	✓		EIA Reference case
Natural gas; net pipeline/LNG exports	✓		EIA Reference case
Oil price, WTI	✓		EIA Reference case
Fuel Oil price; locational values	✓	✓	EIA Reference case - WTI + AEP Fundamentals
Uranium prices		✓	AEP Fundamentals
Other Fuel(Biofuel, etc...)	✓		EIA Reference case
New gen unit options and capital costs	✓		EIA Reference case
Existing gen units	✓		EIA Reference case
Announced new gen units	✓		EIA Reference case
Aged-out retirements of existing gen units	✓		EIA Reference case
Gen unit maintenance schedule		✓	AEP Fundamentals
Gen unit outages		✓	AEP Fundamentals
Unit-level emission rates; CO_2, SO_2, NO_x		✓	US EPA CEMS data
Application of a CO_2 burden		✓	AEP Environmental
REC		✓	AEP Regulatory Forecast
PTC	✓		EIA Reference case
ITC	✓		EIA Reference case
State-mandated Renewable Portfolio Standards		✓	AEP Environmental
Reporting parameters; Peak/Off-Peak/NERC Holidays		✓	PJM/SPP/other RTO and/or internal guidelines
Transmission/links between Zones		✓	AEP Fundamentals

The Fundamentals Forecasts incorporates requirements of the Virginia Clean Energy Act and the Regional Greenhouse Gas Initiative (RGGI) for both APCo and Dominion:

- Including Virginia in the RGGI, applying RGGI CO_2 prices through 2027 before switching to an assumption of a higher $15/metric ton national standard in 2028
- Applying the Virginia RPS program to Phase I and Phase II utilities within the state
- Retiring all fossil units named in the VCEA law by stated retirement dates
- Retiring all remaining Phase I fossil units by 2050 and Phase II fossil units by 2045
- Including the resource additions required for Dominion under the VCEA based upon the Company's understanding of those requirements

The Aurora model iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions, and capital costs, among others. Ultimately, Aurora creates a weather-normalized, long-term forecast of the market in which a utility would be operating. AEPSC also has ample energy market research information available for its reference, which includes third-party consultants, industry groups, governmental agencies, trade press, investment community, AEP-internal expertise, various stakeholders, and others. The Aurora model is widely used by utilities for integrated resource and transmission planning, power cost analysis

and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada, and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora model.

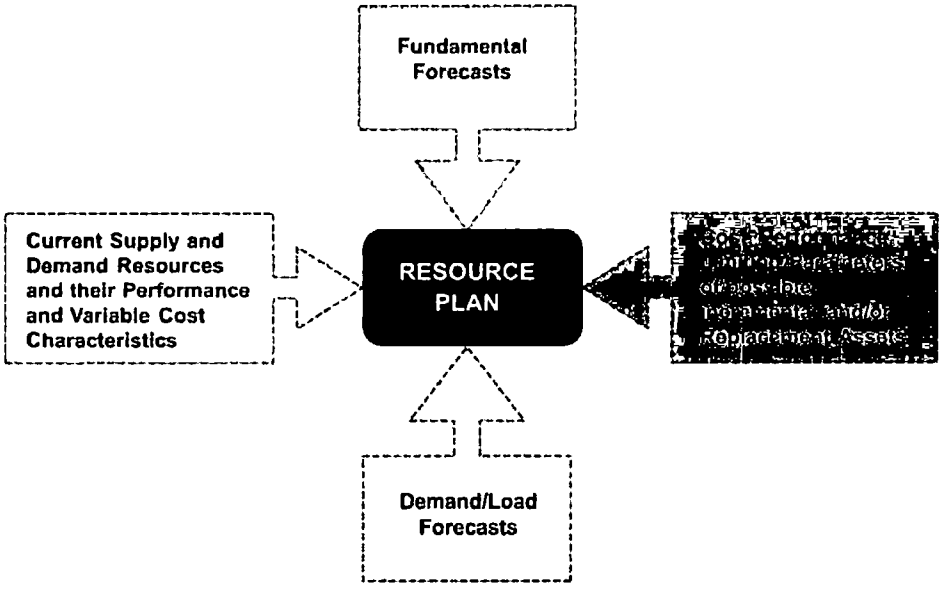
The annual results from each scenario developed are shown in Appendix A and include on-peak and off-peak energy prices, natural gas prices, coal prices, CO_2 prices and capacity prices.

3.6 Determining Compliant VCEA Plans

For the purposes of modeling compliance with the VCEA, APCo used a process nearly identical to its typical IRP process, which used the Plexos® model to address the gap between resource needs and current resources, while also including minimums related to the requirements established under the VCEA for energy from renewable resources, energy savings from energy efficiency resources and capacity from energy storage resources.

Given the cost and performance parameters around sets of potentially available proxy resources–both supply and demand side–and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing proxies including CO_2, as well as projections of energy usage and peak demand, Plexos® will return the optimal suite of proxy resources (portfolio) that meet the resource need. Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the net present value of the resulting stream of revenue requirements. The least cost option is considered the optimum portfolio for that unique input parameter scenario.

FIGURE 3: RESOURCE PLANNING DIAGRAM



4.0 Supply- and Demand-side Resource Options

Supply-side resource options including natural gas base/intermediate and peaking generating technologies and intermittent renewable resources including large-scale solar, wind and battery storage were selectively made available in different scenarios to develop compliant plans.[6] To reduce the computational problem size within Plexos®, the number of alternatives explicitly modeled was reduced through an economic screening process that analyzed various supply options and developed a quantitative comparison levelized over technologies life cycle. It is important to note that alternative technologies with comparable cost and performance characteristics, subject to limitations included in Section 56-585.5, can ultimately be substituted, should technological or market-based profile changes warrant.

Table 11 includes a summary of the technologies made available to the model, depending upon scenario, and their associated performance parameters. These generation technologies were intended to represent reasonable proxies for each capacity type (base-load, intermediate, peaking). Subsequent substitution of specific technologies could occur in any later plan, based on emerging economic or non-economic factors not yet identified.

Other generation resource technologies were not made available to Plexos® due to their respective costs, and to improve modeling process time. Technologies such as natural gas resources with carbon capture and storage, hydrogen-capable combustion turbines, long duration storage, and small modular nuclear reactors were evaluated and found not to be competitive on cost when compared to the resource types shown in Table 11 which were made available to Plexos®, APCo will continue to monitor developments in these and other technologies and including cost, availability, and the availability of federal tax credits, which could make these resources more attractive options in the future.

[6] The Company referred to the EIA ANNUAL ENERGY OUTLOOK 2020 report (https://www.eia.gov/outlooks/aeo/pdf/aeo2020.pdf) and the associated EIA Capital Cost and Performance Characteristic Estimate for Utility Scale Electric Power Generating Technologies (https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf) to inform the analysis process.

TABLE 11: GENERATION TECHNOLOGY OPTIONS (2021$)

AEP System

New Generation Technologies

Key Supply-Side Resource Option Assumptions (a)(b)(d)

Type	Capability (MW) (e) Std. ISO	Summer	Winter	Installed Cost (d,f) ($/kW)	Capacity Factor (%)	LCOE (g) ($/MWh)
Base Load						
COMB TURBINE H CLASS, 1100-MW COMBINED CYCLE (c)	1,030	1,010	1,070	1,100	75	55.5
COMB TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW (c)	420	410	440	1,200	75	58.9
Peaking						
COMB TURBINE F CLASS, 240-MW SIMPLE CYCLE (c)	230	230	250	800	25	95.0
COMB TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE (c)	110	100	110	1,300	25	128.4
INTERNAL COMBUSTION ENGINES, 20 MW (c)	20	20	20	2,100	25	173.9
Intermittent						
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH (c)	50	50	50	1,472	25	156.7
SOLAR PHOTOVOLTAIC WITH BATTERY ENERGY STORAGE SYSTEM, 150 MWx200 MWh (h)	150	150	150	2,041	20	101.7
ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW (i)	200	200	200	1,505	35	40.3
SOLAR PHOTOVOLTAIC, 150 MWAC (h)	150	150	150	1,469	24	57.1

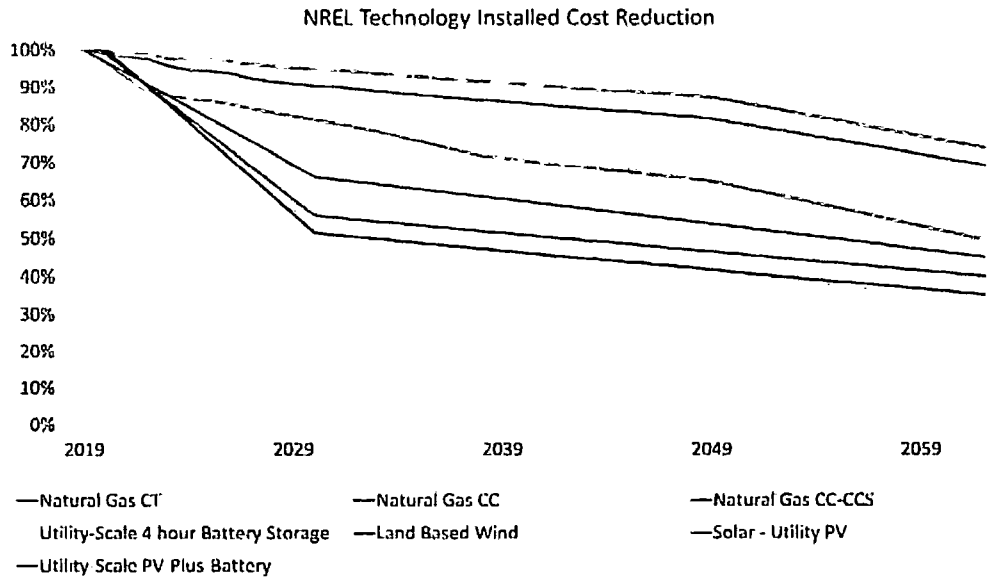
Notes:
(a) Costs and performance data informed by EIA report Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (Feb 2020)
(b) Installed cost, capability and heat rate numbers have been rounded
(c) All costs in 2021 dollars, except as noted. Costs adjustments made based on EIA report Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2020 - Region 11 (PJMW)
(d) $/kW costs are based on summer capability
(e) All Capabilities adjusted by the Performance Adjustment Factors defined in the reference report (a)
(f) Total Plant Investment Cost w/AFUDC (AEP rate of 6.41%,site rating $/kW)
(g) Levelized cost of energy based on capacity factors shown in table
(h) Dollars are in 2023 informed by ApCo RFP
(i) Dollars are in 2023 informed by Bloomberg New Energy Finance's (BNEF) 2H 2020 U.S. Renewable Energy Market Outlook

For this analysis, the Company adopted "learning curve" forecasts published by the National Renewable Energy Laboratory (NREL) in its 2021 Annual Technology Baseline (ATB)[7] for capital costs for all resource types and for wind and solar O&M costs. The notion behind learning curve forecasts is that over time real costs will come down due to economies of scale, technology improvements, manufacturing improvements, and other factors. NREL forecasts that overnight installed capital costs will decline over time for all of these resource options. These effects of the cost reduction rates as a percentage of 2019 price are illustrated in Figure 4 and applied to the technology installed cost forecasts used in the Plexos® modeling. For a table of the overnight installed cost per technology in 2019 real dollar terms with the NREL learning rates, please see Appendix E: Overnight Installed Cost of Technologies in 2019 Real Dollars ($/kW) The Company then applied a forecasted inflation rate to these real dollar

[7] https://atb.nrel.gov/

amounts to convert them to the nominal dollars over the 30 year forecast period, for the purposes of determining the actual future installation costs for each resource type.

FIGURE 4: NREL CAPITAL COST LEARNING CURVES (2019$)



4.1 Power Purchase Agreement (PPA) Options

Consistent with the requirements in Section 56-585.5.D.4, the Plan reflects, in the aggregate and over its duration, a 35% PPA – 65% ownership split for the Virginia jurisdictional share of new Solar and Wind resources. The modeling attempted to maintain approximately this ownership to PPA ratio over a period of years, not in each individual year. In practice, the amount of PPA versus owned wind and solar added in any one year will be the result of competitive solicitations subject to regulatory approval.

PPA resource costs were informed from the results of the RFPs APCo issued in 2021. The PPA bids in response to those RFPs were on average 8% less expensive than owned asset bids. This difference was used as an initial proxy for this analysis to determine the levelized PPA costs relative to levelized owned costs for solar, wind and hybrid solar resources and are not reflective of long-term pricing differences including tax credit effects. This does not necessarily reflect the results of future RFPs and does not include other factors both explicit and implicit regarding ownership benefits. Actual owned and PPA resource costs will be identified in future solicitations for specific resources and may depend on multiple factors including federal tax policy.

4.2 Baseload & Peaking Resource Options

For Baseload resources, the Company modeled two natural gas combined cycle configurations shown in Table 11, the multi-shaft 1,100 MW resource and the single shaft, 430 MW resource. For Peaking resource options, the Company modeled the three resources including a 240 MW combustion turbine (CT), a 105 MW aero-derivative engine (AD) and a 20 MW Reciprocating Internal Combustion Engine (RICE).

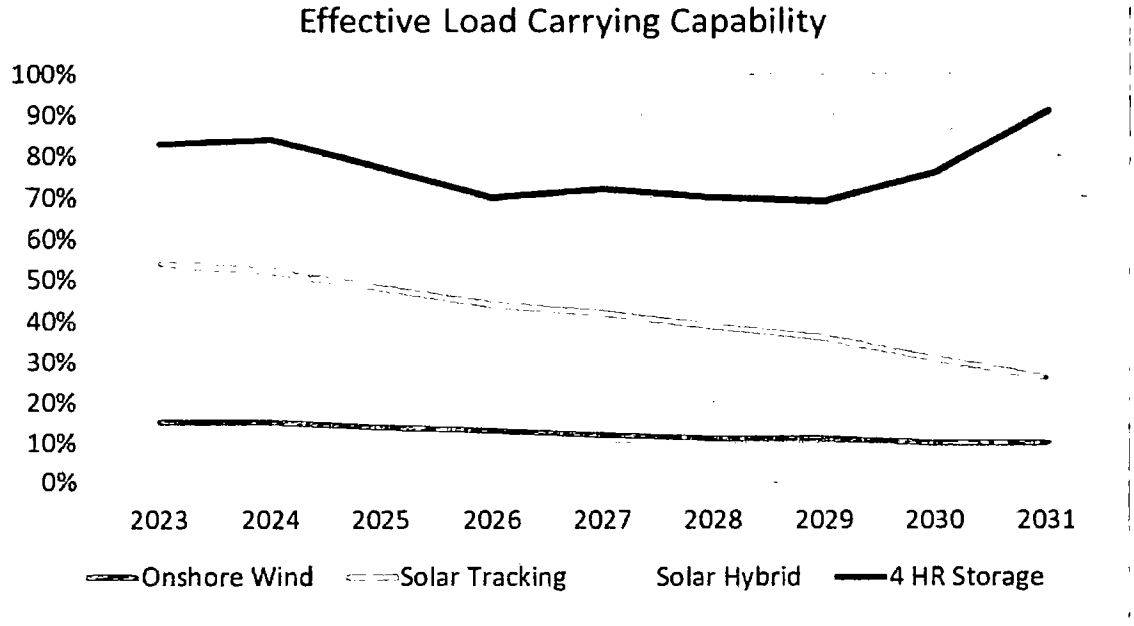
4.3 Intermittent and Renewable Resource Options

Various intermittent and renewable generating technologies were available for selection by the model, with constraints for each year equivalent to the requirements of the VCEA for Scenarios 1-4. Development of these resources continue to grow as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs.

Renewable energy resources, because of their intermittent nature, typically provide more energy value than capacity value, and PJM continues to refine its guidance on the Effective Load Carrying Capability (ELCC) for intermittent resources. In general, under the current PJM draft guidance, as intermittent resources continue to increase in relation to the total of all PJM resources, the planning capacity credit of new renewable resources added to the system will decline. The Company referred to PJM's July 2021 ELCC Report[8] to inform the plan for intermittent resource contributions to the Company's capacity obligations. A summary chart of the ELCC levels assumed in this plan is shown in Figure 5. PJM's July 2021 ELCC Report did not produce projections beyond 2031. For the Company's analysis, the 2031 ELCC values were held constant until the end of the planning horizon.

[8] https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-for-july-2021-results.ashx

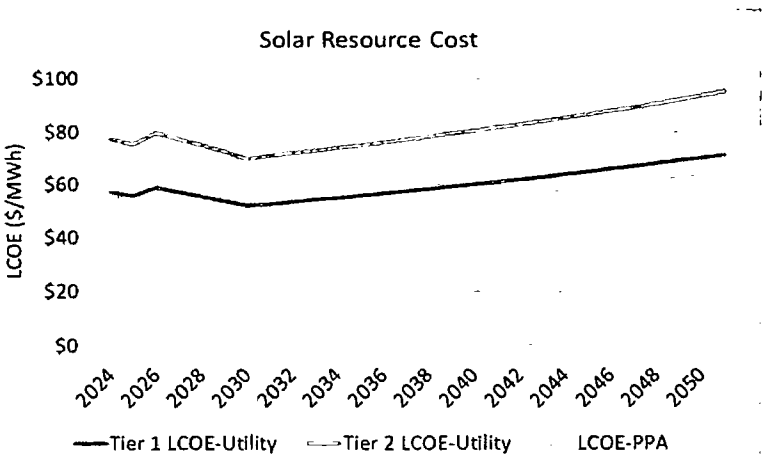
FIGURE 5: PJM EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)



4.3.1 Solar

Large-scale solar resources were available starting in 2025. The Company relied on information from the RFP of owned assets for APCo to model prospective owned solar costs for assets to be placed in service in early 2025. Tier 1 build cost was based upon the top bid in the RFP and Tier 2 based upon the average of bids excluding winning bid. Figure 6 illustrates the forecasted Utility Tier 1, Tier 2, and PPA Solar levelized cost of energy (LCOE) through time. The costs included in these estimates include all costs that would be expected, including a return on rate base, depreciation, land leases, operations and maintenance expense, property taxes, insurance, asset retirement costs, and normalization of the solar investment tax credit (ITC). The property tax and land lease assumptions are tailored to this analysis based on the Company's experience with tax rates in its service territory, and from evaluating specific resources located in both Virginia and in other PJM states.

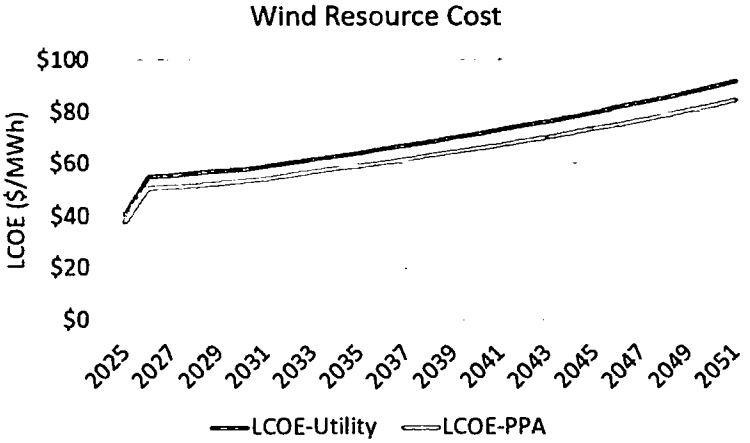
FIGURE 6: SOLAR RESOURCE LCOE



4.3.2 Large-Scale Wind

For Portfolios 1-5, the Company assumed a 35% capacity factor for the new wind resource. Additionally, the Company prepared Portfolio 6 in which the wind capacity factors were assumed to be equivalent to historical 30.4% capacity factor of APCo's existing wind resources. The build cost was based on Bloomberg New Energy Finance's (BNEF) 2H 2020 U.S. Renewable Energy Market Outlook. Figure 7 illustrates the forecasted Utility and PPA Wind LCOEs. The increase from 2025 to 2026 in this figure is due to the expiration of the currently available wind Federal production tax credits. Increases after 2026 are inflation driven.

FIGURE 7: WIND RESOURCE LCOE



4.3.3 Energy Storage

The stand-alone Energy Storage resource modeled in this plan is a Lithium-ion storage technology and has a nameplate rating of 50 MW/200 MWh, with a round trip efficiency of

82.3%. The modeling of Energy Storage utilized the values shown in Table 12, with the nameplate rating adjusted from 50 MW to 25 MW to align with the storage levels in the Commission's order regarding the interim requirements. A Storage PPA option was not modeled as separate resource from an owned storage resource, under the assumption that the cost of the solar resource included in the model represents a blend of owned and PPA. Both PPA and owned storage resources will be considered in future RFPs.

4.3.4 Hybrid Solar / Storage

Hybrid Solar systems include a Solar PV plant with a 4 hour closed loop battery storage system associated with it. For this analysis, a 150 MW_{ac} solar plant was modeled, coupled with a 50 MW (200 MWh) Li-Ion Battery Energy Storage system.

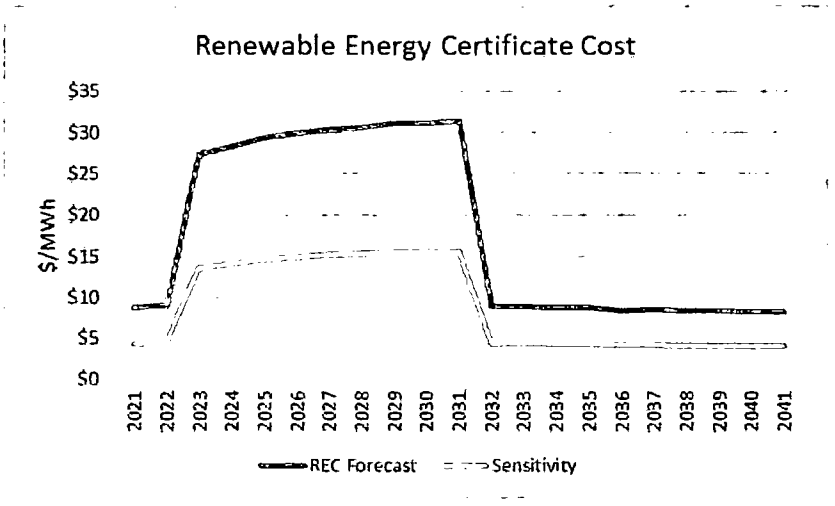
4.3.5 Renewable Energy Certificates (RECs)

The Company included RECs as a RPS energy compliance option in the Plexos® modeling, allowing the model to choose whether to build physical resources or purchase RECs based on economics. In this analysis a 150 MW block of utility solar with an assumed ~350 GWh set the size for a single REC addition in the model. The first year when RECs could be added was assumed to be 2025. A third party forecast provided by S&P Global[9], as shown in Figure 8, was used for the base REC price forecast in all portfolios. The number of RECs selected by the model in each portfolio is presented in Appendix B. Higher and lower priced REC sensitivity cases were also prepared.

A lower priced REC sensitivity case was also prepared, based on an assumption that RECs would be available of 50% of the cost of the base REC forecast curve. That price curve is also shown in Figure 8. The results of that sensitivity analysis are presented in Section 5.

[9] S&P Global, SPGlobalMI_RECForecast_2021Q2_06302031, available by subscription.

FIGURE 8: REC PRICE FORECAST



4.3.6 Annual and Cumulative Resource Limits

For each portfolio, annual and cumulative intermittent and renewable resource limits were determined based on simultaneous consideration of multiple regulatory requirements. All six portfolios are VCEA-compliant. Different limits were necessarily applied to each portfolio based on the unique assumptions of each portfolio, such as the assumed retirement date of Amos and Mountaineer, as well as whether gas-fired options were available. Table 12 contains a summary of the limits for the wind, solar, storage, and REC options included in the modeling for each portfolio.

TABLE 12: NEW RESOURCE LIMITATIONS

New Resource Assumptions							
Resource Type	**First Year Available**	**Life**	**Portfolio 1,2,6**	**Portfolio 3 &4**	**Portfolio 5**	**Individual Technology Total**	**Cumulative Technology Total**
Solar PPA	1/1/2025	35 years	150 MW/yr	300 MW/yr	150 MW/yr	900 MW	3,150 MW
Solar Utility T1		35 years	300 MW/yr	600 MW/yr	300 MW/yr	2,100 MW	
Solar Utility T2		35 years	150 MW/yr	300 MW/yr	150 MW/yr		
Solar Hybrid		35 years	150 MW Block 450 MW/yr			1,050 MW	
Wind PPA Limits	1/1/2026	30 years	100 MW/yr	300 MW/yr	100 MW/yr	350 MW Total	950 MW
Wind Owned Limits	1/1/2026	30 years	200 MW/yr	600 MW/yr	-	600 MW Total	
Wind Owned Limits	1/1/2026	30 years	- - - - -	- - - - -	2026 1,200 MW 2028 2,600 MW 2030 3,600 MW 2032 4,600 MW 2035 5,000 MW	5,000 MW Total	5,350 MW
Renewable Energy Certificates	1/1/2025	5 years	20 Blocks/yr			~7,000 GWh	~7,000 GWh
Stand Alone Storage	1/1/2025	10 years	2,500 MW/yr			12,500 MW	12,500 MW
NG 240 MW Combustion Turbine	1/1/2026	30 years	P1 unlimited P2 N/A	P3 unlimited P4 N/A	N/A	Unlimited	Unlimited
NG 1,100 MW Combined Cycle	1/1/2026	30 years	P1 unlimited P2 N/A	P3 unlimited P4 N/A	N/A	Unlimited	Unlimited

The primary regulatory constraints considered in setting the annual and cumulative resource limits were 1) PJM minimum capacity requirements; 2) VCEA annual Virginia-jurisdictional renewable energy targets; 3) VCEA 35% wind and solar PPA requirements; and 4) near term (prior to 2030) VCEA wind, solar, and storage new resource requirements. All of these constraints must be applied simultaneously. Compliance with the minimum obligations under any one of these requirements, such as the VCEA annual energy targets, could and did lead to substantial over-compliance with other requirements, such as PJM's minimum capacity requirement, in some portfolios. In addition, to the extent possible, the Company spread out resource additions gradually over time, rather than all at once, to help mitigate near-term rate increases that can result from adding required resources. This can result in the addition of resources earlier than the year in which one of these regulatory obligations requires them. Finally, there are practical limits regarding the absolute levels of cost-effective renewable capacity that are available in Virginia and more broadly across PJM.

The timing of the assumed retirement of Amos and Mountaineer also impacted the resource limitations. This resulted in higher annual wind and solar limits in Portfolios 3 and 4 than in Portfolios 1 and 2 in order to allow more resources to be constructed during the period prior to Amos and Mountaineer retiring in 2028. This constraint also resulted in a high annual limit for storage resources in all portfolios in order to allow enough storage to be selected for its capacity to replace a substantial share of the capacity that would be lost when Amos and

Mountaineer retire. This also drives a high cumulative lifetime storage limit, if storage is selected again at the end of its 10-year useful life, if the model deemed it to be the most economic option available.

Lastly, the near-term availability of Virginia domiciled wind and solar resources was considered. Based on the numbers of bids received of each resource type in the two RFP's issued in 2021, solar resources are expected to be more widely available than wind, and the quantity of wind MW available in Virginia could be quite limited. As a result, higher limits were allowed for solar than wind.

By choosing these limits for the various scenarios, the Company is not expressing an opinion regarding whether these levels of resources are in fact available, or whether adding that level of a given resource is desired. The assumption that 2,500 MW of storage could be added to a Company the size of APCo in any one year, or even cumulatively prior to 2030, is particularly aggressive. These limits are simply an attempt to give the model enough available capacity and energy options to meet the necessary PJM and VCEA requirements in all years of the analysis from a portfolio of all of the available resource types under each scenario.

4.4 Demand-Side Resource Options

4.4.1 Energy Efficiency

The Company included both Residential and Commercial/Industrial energy efficiency bundles as demand-side resource options to consider. Table 13 shows the Residential Bundles cost and potential by year, and Table 14 shows the Commercial/Industrial Bundles included in the model.

TABLE 13: RESIDENTIAL EE BUNDLES

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2022-2026	Yearly Potential Savings (MWh) 2027-2031	Yearly Potential Savings (MWh) 2032-2036	Yearly Potential Savings (MWh) 2037-2041	Bundle Life
Thermal Shell - AP	$0.21	6,621	2,794	3,120	2,824	10
Thermal Shell - HAP	$0.31	20,514	54	0	0	10
Heating/Cooling - AP	$0.68	49,323	7,365	0	0	18
Heating/Cooling - HAP	$0.96	7,576	0	0	0	18
Water Heating - AP	$0.24	34,877	11,711	13,000	6,265	14
Water Heating - HAP	$0.35	82,827	10,498	10,391	0	14
Appliances - AP	$0.22	33,242	3,018	3,133	2,460	13
Appliances - HAP	$0.31	7,449	0	0	0	13
Lighting - AP	$0.08	1,669	0	0	0	31
Lighting - HAP	$0.13	1,103	0	0	0	30
Behavioral Programs	$0.04	23,137	0	0	0	2

TABLE 14: COMMERCIAL EE BUNDLES

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2022-2026	Yearly Potential Savings (MWh) 2027-2031	Yearly Potential Savings (MWh) 2032-2036	Yearly Potential Savings (MWh) 2037-2041	Bundle Life
Heat Pump - AP	$9.00	2,985	0	0	0	15
Heat Pump - HAP	$13.49	199	0	0	0	15
HVAC Equipment - AP	$0.16	2,718	0	0	0	15
HVAC Equipment - HAP	$0.24	1,624	0	0	0	15
Indoor Screw-In Lighting - AP	$0.01	2,345	0	0	0	6
Indoor Screw-In Lighting - HAP	$0.02	995	0	0	0	6
Indoor HID/Fluor. Lighting - AP	$0.11	15,646	1,409	0	0	14
Indoor HID/Fluor. Lighting - HAP	$0.16	1,738	0	0	0	14
Outdoor Lighting - AP	$0.38	3,946	567	0	0	15
Outdoor Lighting - HAP	$0.57	4,384	0	0	0	15

4.4.2 Demand Response

The Company included one Demand Response resource option to be considered, which is based on a Residential Bring-Your-Own-Thermostat program. Table 15 shows the characteristics of this resource.

TABLE 15: APCO DEMAND RESPONSE

Sector	Participants	Demand Savings (kW)	Energy Savings (kWh)	Enrollment Cost	Annual Cost	Total First Year Cost	Service Life (Years)
Residential	2,500	3,375	70,000	$165,000	$950,500	$1,115,500	7

4.4.3 Volt VAR Optimization

The Company included Volt VAR Optimization (VVO), which represents a form of voltage control that allows the grid to operate more efficiently as a resource option. VVO sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment in order to optimize power factor and voltage levels. Power factor is the ratio of real or active power (MW) to apparent power (MVA), and is a characteristic of electric power flow that is controlled to optimize power flow on an electric network. Power factor optimization also improves energy efficiency by reducing losses on the system. VVO enables Conservation Voltage Reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, thereby allowing customers to use less energy without any changes in behavior or appliance efficiencies.

Although there are no "embedded" incremental VVO load reduction impacts implicit in the load forecast, VVO has been modeled as a unique EE resource. Table 16 below shows the resource characteristics of the VVO resources made available to the model in all portfolios.

TABLE 16: VVO RESOURCES

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	36	$12,600,000	$378,000	11,172	45,996
2	36	$12,600,000	$378,000	9,639	39,684
3	36	$12,600,000	$378,000	8,799	36,227
4	36	$12,600,000	$378,000	8,298	34,163
5	36	$12,600,000	$378,000	7,826	32,222
6	36	$12,600,000	$378,000	7,458	30,705
7	36	$12,600,000	$378,000	7,126	29,340
8	36	$12,600,000	$378,000	6,884	28,343
9	36	$12,600,000	$378,000	6,629	27,292
10	36	$12,600,000	$378,000	6,435	26,493
11	36	$12,600,000	$378,000	6,186	25,470
12	36	$12,600,000	$378,000	5,909	24,329
13	36	$12,600,000	$378,000	5,849	24,081
14	36	$12,600,000	$378,000	5,473	22,532

4.4.4 Distributed Generation

The Company included both the capacity and energy associated with Distributed Generation in all six portfolios. Figure 9 shows the cumulative nameplate DG MW forecasted to be installed. For capacity planning purposes, the Company referred to the PJM ELCC report discussed in Section 4.3, beginning at 38% of the nameplate value in 2023. The associated energy produced from this customer-owned DG was assumed to not be part of the Company's achievement of the VCEA RPS requirement.

Attachment 81

VIRGINIA ACTS OF ASSEMBLY — CHAPTER

An Act to amend and reenact §§ 56-581, 56-585.1, 56-585.1:4, and 56-599 of the Code of Virginia and to amend the Code of Virginia by adding a section numbered 56-249.6:1, relating to Virginia Electric Utility Regulation Act; financing for certain deferred fuel costs; review proceedings; rates; return on common equity; rate adjustment clauses; capitalization ratio.

[H 1770]

Approved

Be it enacted by the General Assembly of Virginia:

1. That §§ 56-581, 56-585.1, 56-585.1:4, and 56-599 of the Code of Virginia are amended and reenacted and that the Code of Virginia is amended by adding a section numbered 56-249.6:1 as follows:

§ 56-249.6:1. Financing for certain deferred fuel costs.

A. Notwithstanding the provisions of § 56-249.6 or Chapter 3 (§ 56-55 et seq.), an electric utility, on or before July 1, 2024, may petition the Commission for a financing order and the Commission shall either issue (i) such financing order or (ii) an order rejecting the petition, no more than four months from the date of filing such petition and in accordance with the requirements of subdivision 2.

1. The petition shall include (i) an estimate of the total amount of deferred fuel costs that the electric utility has incurred over the time period noted in the petition; (ii) an indication of whether the electric utility proposes to finance all or a portion of the deferred fuel costs using one or more series or tranches of deferred fuel cost bonds; (iii) an estimate and details of the financing costs related to the deferred fuel costs to be financed through the deferred fuel cost bonds; (iv) an estimate of the deferred fuel cost charges necessary to recover the deferred fuel costs and all financing costs and the proposed period for recovery of such costs; (v) a description of any benefits expected to result from the issuance of deferred fuel cost bonds, including the avoidance of or significant mitigation of abrupt and significant increases in rates to the electric utility's customers for the applicable time period; and (vi) direct testimony and exhibits supporting the petition. If the electric utility proposes to finance a portion of the deferred fuel costs, the electric utility shall identify in the petition the specific amount of deferred fuel costs for the applicable time period to be financed using deferred fuel cost bonds. By electing not to finance a portion of the deferred fuel costs for an applicable time period using deferred fuel cost bonds, an electric utility shall not be deemed to waive its right to recover such costs pursuant to a separate proceeding with the Commission.

2. a. If an electric utility petitions the Commission for a financing order pursuant to this section, following notice and an opportunity for hearing, the Commission shall either issue (i) a financing order or (ii) an order rejecting the petition, not more than four months from the date of filing such petition.

b. A financing order issued by the Commission pursuant to this section shall include:

(1) The amount of deferred fuel costs to be financed using deferred fuel cost bonds. The Commission shall describe and estimate the amount of financing costs that may be recovered through deferred fuel cost charges. The financing order shall also specify the period over which deferred fuel costs and financing costs may be recovered and whether the deferred fuel cost bonds may be offered and issued in one or more series or tranches during a fixed period not to exceed one year after the date of the financing order;

(2) A finding that the proposed issuance of deferred fuel cost bonds is in the public interest and the associated deferred fuel cost charges are just and reasonable;

(3) A finding that the structuring and pricing of the deferred fuel cost bonds are reasonably expected to result in reasonable deferred fuel cost charges consistent with market conditions at the time the deferred fuel cost bonds are priced and the terms set forth in such financing order;

(4) A requirement that, for so long as the deferred fuel cost bonds are outstanding and until all financing costs have been paid in full, the imposition and collection of deferred fuel cost charges authorized under a financing order shall be non-bypassable and paid by all retail customers of the electric utility, irrespective of the generation supplier of such customer, except for an exempt retail access customer;

(5) A formula-based true-up mechanism for making annual adjustments to the deferred fuel cost charges that customers are required to pay pursuant to the financing order and for making any adjustments that are necessary to correct for any overcollection or undercollection of the charges or to otherwise ensure the timely payment of deferred fuel cost bonds and financing costs and other required amounts and charges payable in connection with the deferred fuel cost bonds;

(6) The deferred fuel cost property that is, or shall be, created in favor of an electric utility or its successors or assignees and that shall be used to pay or secure deferred fuel cost bonds and all financing costs;

(7) The authority of the electric utility to establish the terms and conditions of the deferred fuel cost bonds, including repayment schedules, expected interest rates, the issuance in one or more series or tranches with different maturity dates, and other financing costs;

(8) A finding that the deferred fuel cost charges shall be allocated among customer classes in accordance with the methodology approved in the electric utility's last fuel factor proceeding;

(9) A requirement that after the final terms of an issuance of deferred fuel cost bonds have been established and before the issuance of deferred fuel cost bonds, the electric utility determines the resulting initial deferred fuel cost charge in accordance with the financing order and that such initial deferred fuel cost charge be final and effective upon the issuance of such deferred fuel cost bonds without further Commission action so long as such initial deferred fuel cost charge is consistent with the financing order;

(10) A method of tracing funds collected as deferred fuel cost charges, or other proceeds of deferred fuel cost property, and a requirement that such method be the method of tracing such funds and determining the identifiable cash proceeds of any deferred fuel cost property subject to the financing order under applicable law; and

(11) Any other conditions not otherwise inconsistent with this section that the Commission determines are appropriate.

c. A financing order issued to an electric utility may provide that creation of the electric utility's deferred fuel cost property is conditioned upon, and simultaneous with, the sale or other transfer for the deferred fuel cost property to an assignee and the pledge of the deferred fuel cost property to secure deferred fuel cost bonds.

d. If the Commission issues a financing order, the Commission shall establish a protocol for the electric utility to annually file a petition or, in the Commission's discretion, a letter setting out application of the formula-based mechanism and, based on estimates of consumption for each rate class and other mathematical factors, requesting administrative approval to make applicable adjustments. The review of the filing shall be limited to determining whether there are any mathematical or clerical errors in the application of the formula-based mechanism relating to the appropriate amount of any overcollection or undercollection of deferred fuel cost charges and the amount of an adjustment. The adjustments shall ensure the recovery of revenues sufficient to provide for the payment of principal, interest, acquisition, defeasance, financing costs, or redemption premium and other fees, costs, and charges in respect of deferred fuel cost bonds approved under the financing order. Within 30 days after receiving an electric utility's request pursuant to this subdivision d, the Commission shall either approve the request or inform the electric utility of mathematical or clerical errors in its calculation. If the Commission informs the electric utility of mathematical or clerical errors in its calculation, the electric utility may correct its error and refile its request. The time frames previously described in this subdivision d shall apply to a refiled request.

e. Subsequent to the transfer of deferred fuel cost property to an assignee or the issuance of deferred fuel cost bonds authorized thereby, whichever is earlier, a financing order shall be irrevocable and, except for changes made pursuant to the formula-based mechanism authorized in this section, the Commission shall not amend, modify, or terminate the financing order by any subsequent action or reduce, impair, postpone, terminate, or otherwise adjust deferred fuel cost charges approved in the financing order. After the issuance of a financing order, the electric utility shall retain sole discretion regarding whether to assign, sell, or otherwise transfer deferred fuel cost property or to cause deferred fuel cost bonds to be issued, including the right to defer or postpone such assignment, sale, transfer, or issuance.

3. At the request of an electric utility, the Commission may commence a proceeding and issue a subsequent financing order that provides for refinancing, retiring, or refunding deferred fuel cost bonds issued pursuant to the original financing order if the Commission finds that the subsequent financing order satisfies all of the criteria specified in this section for a financing order. Effective upon retirement of the refunded deferred fuel cost bonds and the issuance of new deferred fuel cost bonds, the Commission shall adjust the related deferred fuel cost charges accordingly.

4. a. A financing order shall remain in effect and deferred fuel cost property under the financing order shall continue to exist until deferred fuel cost bonds issued pursuant to the financing order have been paid in full or defeased and, in each case, all Commission-approved financing costs of such deferred fuel cost bonds have been recovered in full.

b. A financing order issued to an electric utility shall remain in effect and unabated notwithstanding the reorganization, bankruptcy or other insolvency proceedings, merger, or sale of the electric utility or its successors or assignees.

B. 1. The Commission shall not, in exercising its powers and carrying out its duties regarding any matter within its authority pursuant to this chapter, and notwithstanding any other provision of law, consider the deferred fuel cost bonds issued pursuant to a financing order to be the debt of the electric utility other than for federal income tax purposes, consider the deferred fuel cost charges paid under the financing order to be the revenue of the electric utility for any purpose, or consider the deferred fuel costs or financing costs specified in the financing order to be the costs of the electric utility, nor shall the Commission determine any action taken by an electric utility which is consistent with the financing order to be unjust or unreasonable.

2. The Commission shall not order or otherwise directly or indirectly require an electric utility to use deferred fuel cost bonds to finance any project, addition, plant, facility, extension, capital improvement, equipment, or any other expenditure. After the issuance of a financing order, the electric utility shall retain sole discretion regarding whether to cause the deferred fuel cost bonds to be issued, including the right to defer or postpone such sale, assignment, transfer, or issuance. Nothing shall prevent the electric utility from abandoning the issuance of deferred fuel cost bonds under the financing order by filing with the Commission a statement of abandonment and the reasons therefor. The Commission shall not deny an electric utility its right to recover deferred fuel costs as otherwise provided in this section, or refuse or condition authorization or approval of the issuance and sale by an electric utility of securities or the assumption by the electric utility of liabilities or obligations, solely because of the potential availability of deferred fuel cost bond financing.

C. The electric bills of an electric utility that has obtained a financing order and caused deferred fuel cost bonds to be issued shall comply with the provisions of this subsection; however, the failure of an electric utility to comply with this subsection does not invalidate, impair, or affect any financing order, deferred fuel cost property, deferred fuel cost charge, or deferred fuel cost bonds. The electric utility shall:

1. Explicitly reflect that a portion of the charges on any electric bill represents deferred fuel cost charges approved in a financing order issued to the electric utility and, if the deferred fuel cost property has been transferred to an assignee, such bill shall include a statement to the effect that the assignee is the owner of the rights to deferred fuel cost charges and that the electric utility or another entity, if applicable, is acting as a collection agent or servicer for the assignee. The tariff applicable to customers must indicate the deferred fuel cost charge and the ownership of the charge; and

2. Include the deferred fuel cost charge on each customer's bill as a separate line item and include both the rate and the amount of the charge on each bill.

D. 1. The following provisions shall be applicable to deferred fuel cost property:

a. All deferred fuel cost property that is specified in a financing order shall constitute an existing, present intangible property right or interest therein, notwithstanding that the imposition and collection of deferred fuel cost charges depends on the electric utility, to which the financing order is issued, performing its servicing functions relating to the collection of deferred fuel cost charges and on future electricity consumption. The deferred fuel cost property shall exist (i) regardless of whether or not the revenues or proceeds arising from the deferred fuel cost property have been billed, have accrued, or have been collected and (ii) notwithstanding the fact that the value or amount of the deferred fuel cost property is dependent on the future provision of service to customers by the electric utility or its successors or assignees and the future consumption of electricity by customers;

b. Deferred fuel cost property specified in a financing order shall exist until deferred fuel cost bonds issued pursuant to the financing order are paid in full and all financing costs and other costs of such deferred fuel cost bonds have been recovered in full;

c. All or any portion of deferred fuel cost property specified in a financing order issued to an electric utility may be transferred, sold, conveyed, or assigned to a successor or assignee that is wholly owned, directly or indirectly, by the electric utility and created for the limited purpose of acquiring, owning, or administering deferred fuel cost property or issuing deferred fuel cost bonds under the financing order. All or any portion of deferred fuel cost property may be pledged to secure deferred fuel cost bonds issued pursuant to the financing order, amounts payable to financing parties and to counterparties under any ancillary agreements, and other financing costs. Any transfer, sale, conveyance, assignment, grant of a security interest in or pledge of deferred fuel cost property by an electric utility, or an affiliate of the electric utility, to an assignee, to the extent previously authorized in a financing order, shall not require the prior consent and approval of the Commission;

d. If an electric utility defaults on any required payment of charges arising from deferred fuel cost property specified in a financing order, a court, upon application by an interested party, and without limiting any other remedies available to the applying party, shall order the sequestration and payment of the revenues arising from the deferred fuel cost property to the financing parties or their assignees. Any such financing order shall remain in full force and effect notwithstanding any reorganization, bankruptcy, or other insolvency proceedings with respect to the electric utility or its successors or

assignees;

e. The interest of a transferee, purchaser, acquirer, assignee, or pledgee in deferred fuel cost property specified in a financing order issued to an electric utility, and in the revenue and collections arising from that property, shall not be subject to setoff, counterclaim, surcharge, or defense by the electric utility or any other person or in connection with the reorganization, bankruptcy, or other insolvency of the electric utility or any other entity;

f. Any successor to an electric utility, whether pursuant to any reorganization, bankruptcy, or other insolvency proceeding or whether pursuant to any merger or acquisition, sale, or other business combination, or transfer by operation of law, as a result of electric utility restructuring or otherwise, shall perform and satisfy all obligations of, and have the same rights under a financing order as, the electric utility under the financing order in the same manner and to the same extent as the electric utility, including collecting and paying to the person entitled to receive the revenues, collections, payments, or proceeds of the deferred fuel cost property. Nothing in this subdivision f is intended to limit or impair any authority of the Commission concerning the transfer or succession of interests of public utilities; and

g. Deferred fuel cost bonds shall be nonrecourse to the credit or any assets of the electric utility other than the deferred fuel cost property as specified in the financing order and any rights under any ancillary agreement.

2. The following provisions shall be applicable to security interests:

a. The creation, perfection, and enforcement of any security interest in deferred fuel cost property to secure the repayment of the principal and interest and other amounts payable in respect of deferred fuel cost bonds; amounts payable under any indenture, ancillary agreement, or other financing documents in respect of the deferred fuel costs; and other financing costs shall be governed by this subsection and not by the provisions of the Uniform Commercial Code (Titles 8.1A through 8.9A);

b. A security interest in deferred fuel cost property shall be created and enforceable when all of the following have occurred: (i) a financing order is issued, (ii) value is received by the debtor or seller for such deferred fuel cost property, (iii) the debtor or seller has rights in such deferred fuel cost property or the power to transfer rights in such deferred fuel cost property, and (iv) a security agreement granting such security interest is executed and delivered by the debtor or seller. The description of deferred fuel cost property in a security agreement shall be sufficient if the description refers to this section and the financing order creating the deferred fuel cost property;

c. A security interest shall attach without any physical delivery of collateral or other act and, upon the filing of a financing statement with the Commission, the lien of the security interest shall be valid, binding, and perfected against all parties having claims of any kind in tort, contract, or otherwise against the person granting the security interest, regardless of whether the parties have notice of the lien. Also upon this filing, a transfer of an interest in the deferred fuel cost property shall be perfected against all parties having claims of any kind, including any judicial lien or other lien creditors or any claims of the transferor or creditors of the transferor, and shall have priority over all competing claims other than any prior security interest, ownership interest, or assignment in the property previously perfected in accordance with this section;

d. The Commission shall maintain any financing statement filed to perfect any security interest under this section in the same manner that the Commission maintains financing statements filed by transmitting utilities under the Uniform Commercial Code (Titles 8.1A through 8.9A). The filing of a financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Uniform Commercial Code (Titles 8.1A through 8.9A);

e. The priority of a security interest in deferred fuel cost property shall not be affected by the commingling of deferred fuel cost charges with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all deferred fuel cost charges that are deposited in any cash or deposit account of the qualifying utility in which deferred fuel cost charges have been commingled with other funds and any other security interest that may apply to those funds shall be terminated when they are transferred to a segregated account for the assignee or a financing party;

f. No application of the formula-based adjustment mechanism as provided in this section shall affect the validity, perfection, or priority of a security interest in or transfer of deferred fuel cost property; and

g. If a default or termination occurs under the deferred fuel cost bonds, the financing parties or their representatives may foreclose on or otherwise enforce their lien and security interest in any deferred fuel cost property as if they were secured parties with a perfected and prior lien under the Uniform Commercial Code (Titles 8.1A through 8.9A), and the Commission may order that amounts arising from deferred fuel cost charges be transferred to a separate account for the financing parties' benefit, to which their lien and security interest shall apply. On application by or on behalf of the financing parties, the Commission shall order the sequestration and payment to them of revenues arising from the deferred fuel cost charges.

3. a. Any sale, assignment, or other transfer of deferred fuel cost property shall be an absolute transfer and true sale of and not a pledge of, or secured transaction relating to, the transferor's right, title, and interest in, to, and under the deferred fuel cost property if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer other than for federal and state income tax purposes. For all purposes other than federal and state income tax purposes, the parties' characterization of a transaction as a sale of an interest in deferred fuel cost property shall be conclusive that the transaction is a true sale and that ownership has passed to the party characterized as the purchaser, regardless of any fact or circumstance that might support characterization of the transfer as a secured transaction. A transfer of an interest in deferred fuel cost property shall occur only when all of the following have occurred: (i) the financing order creating the deferred fuel cost property has become effective, (ii) the documents evidencing the transfer of deferred fuel cost property have been executed by the transferor and delivered to the assignee, and (iii) value is received by the transferor for the deferred fuel cost property. After such a transaction, the deferred fuel cost property shall not be subject to any claims of the transferor or the transferor's creditors, other than creditors holding a prior security interest in the deferred fuel cost property perfected in accordance with subdivision 2.

b. The characterization of the sale, assignment, or other transfer as an absolute transfer and true sale and the corresponding characterization of the interest of the assignee as an ownership interest, shall not be affected or impaired by the occurrence of any of the following factors:

(1) Commingling of deferred fuel cost charges with other amounts;

(2) The retention by the seller of (i) a partial or residual interest, including an equity interest, in the deferred fuel cost property, whether direct or indirect, or whether subordinate or otherwise, or (ii) the right to recover costs associated with taxes, franchise fees, or license fees imposed on the collection of deferred fuel cost charges;

(3) Any recourse that the assignee may have against the seller;

(4) Any right or obligation that the seller may have to repurchase the deferred fuel cost charges;

(5) Any indemnification obligations of the seller;

(6) The obligation of the seller to collect deferred fuel cost charges on behalf of the assignee;

(7) The transferor acting as the servicer of the deferred fuel cost charges or the existence of any contract that authorizes or requires the electric utility, to the extent that any interest in deferred fuel cost property is sold or assigned, to agree with the assignee or any financing party that it will continue to operate its system to provide service to its customers, will collect amounts in respect of the deferred fuel cost charges for the benefit and account of such assignee or financing party, and will account for and remit such amounts to or for the account of such assignee or financing party;

(8) The treatment of the sale, conveyance, assignment, or other transfer for tax, financial reporting, or other purposes;

(9) The granting or providing to bondholders of a preferred right to the deferred fuel cost property or credit enhancement by the electric utility or its affiliates with respect to the deferred fuel cost bonds; or

(10) Any application of the formula-based adjustment mechanism as provided in this section.

c. Any right that an electric utility has in the deferred fuel cost property before its pledge, sale, or transfer or any other right created under this section or created in the financing order and assignable under this section or assignable pursuant to a financing order shall be property in the form of a contract right or a chose in action. Transfer of an interest in deferred fuel cost property to an assignee shall be enforceable only when all of the following have occurred: (i) a financing order is issued, (ii) value is received by the transferor for such deferred fuel cost property, (iii) the transferor has rights in such deferred fuel cost property or the power to transfer rights in such deferred fuel cost property, and (iv) transfer documents in connection with the issuance of deferred fuel cost bonds are executed and delivered by the transferor. An enforceable transfer of an interest in deferred fuel cost property to an assignee shall be perfected against all third parties, including subsequent judicial or other lien creditors, when a notice of that transfer has been given by the filing of a financing statement in accordance with subdivision 2 c. The transfer shall be perfected against third parties as of the date of filing.

d. The Commission shall maintain any financing statement filed to perfect any sale, assignment, or transfer of deferred fuel cost property under this section in the same manner that the Commission maintains financing statements filed by transmitting utilities under the Uniform Commercial Code (Titles 8.1A through 8.9A). The filing of any financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Uniform Commercial Code (Titles 8.1A through 8.9A). The filing of such a financing statement shall be the only method of perfecting a transfer of deferred fuel cost property.

e. The priority of a transfer perfected under this section shall not be impaired by any later

modification of the financing order or deferred fuel cost property or by the commingling of funds arising from deferred fuel cost property with other funds. Any other security interest that may apply to those funds, other than a security interest perfected under subdivision 2, shall be terminated when they are transferred to a segregated account for the assignee or a financing party. If deferred fuel cost property has been transferred to an assignee or financing party, any proceeds of that property shall be held in trust for the assignee or financing party.

f. The priority of the conflicting interests of assignees in the same interest or rights in any deferred fuel cost property shall be determined as follows:

(1) Conflicting perfected interests or rights of assignees shall rank according to priority in time of perfection. Priority shall date from the time a filing covering the transfer is made in accordance with subdivision 2 c;

(2) A perfected interest or right of an assignee shall have priority over a conflicting unperfected interest or right of an assignee; and

(3) A perfected interest or right of an assignee shall have priority over a person who becomes a lien creditor after the perfection of such assignee's interest or right.

E. The description of deferred fuel cost property being transferred to an assignee in any sale agreement, purchase agreement, or other transfer agreement, granted or pledged to a pledgee in any security agreement, pledge agreement, or other security document, or indicated in any financing statement, shall only be sufficient if such description or indication refers to the financing order that created the deferred fuel cost property and states that the agreement or financing statement covers all or part of the property described in the financing order. This section shall apply to all purported transfers of, and all purported grants or liens or security interests in, deferred fuel cost property, regardless of whether the related sale agreement, purchase agreement, other transfer agreement, security agreement, pledge agreement, or other security document was entered into, or any financing statement was filed.

F. All financing statements referenced in this section shall be subject to Part 5 of Title 8.9A (§ 8.9A-501 et seq.) of the Uniform Commercial Code, except that the requirement as to continuation statements shall not apply.

G. The laws of the Commonwealth shall govern the validity, enforceability, attachment, perfection, priority, and exercise of remedies with respect to the transfer of an interest or right or the pledge or creation of a security interest in any deferred fuel cost property.

H. Neither the Commonwealth nor its political subdivisions shall be liable on any deferred fuel cost bonds, and the bonds shall not be a debt or a general obligation of the Commonwealth or any of its political subdivisions, agencies, or instrumentalities, nor shall they be special obligations or indebtedness of the Commonwealth or any of its agencies or political subdivisions. An issue of deferred fuel cost bonds shall not, directly, indirectly, or contingently, obligate the Commonwealth or any agency, political subdivision, or instrumentality of the Commonwealth to levy any tax or make any appropriation for payment of the deferred fuel cost bonds, other than in their capacity as consumers of electricity. All deferred fuel cost bonds shall contain on the face thereof a statement to the following effect: "NEITHER THE FULL FAITH AND CREDIT NOR THE TAXING POWER OF THE COMMONWEALTH IS PLEDGED TO THE PAYMENT OF THE PRINCIPAL OF, OR INTEREST ON, THIS BOND."

I. All of the following entities may legally invest any sinking funds, moneys, or other funds in deferred fuel cost bonds:

1. Subject to applicable statutory restrictions on state or local investment authority, the Commonwealth, units of local government, political subdivisions, public bodies, and public officers, except for members of the Commission;

2. Banks and bankers, savings and loan associations, credit unions, trust companies, savings banks and institutions, investment companies, insurance companies, insurance associations, and other persons carrying on a banking or insurance business;

3. Personal representatives, guardians, trustees, and other fiduciaries; and

4. All other persons authorized to invest in bonds or other obligations of a similar nature.

J. 1. The Commonwealth and its agencies, including the Commission, pledge and agree with bondholders, the owners of the deferred fuel cost property, and other financing parties that the Commonwealth and its agencies shall not take any action listed in this subdivision. This subsection does not preclude limitation or alteration if full compensation is made by law for the full protection of the deferred fuel cost charges collected pursuant to a financing order and of the bondholders and any assignee or financing party entering into a contract with the electric utility. The Commonwealth and its agencies, including the Commission, shall not:

a. Alter the provisions of this section that authorize the Commission to create an irrevocable contract right or chose in action by the issuance of a financing order, to create deferred fuel cost

property, and to make the deferred fuel cost charges imposed by a financing order irrevocable, binding, or nonbypassable charges;

b. Take or permit any action that impairs or would impair the value of deferred fuel cost property or the security for the deferred fuel cost bonds or revises the deferred fuel costs for which recovery is authorized;

c. In any way impair the rights and remedies of the bondholders, assignees, and other financing parties; or

d. Except for changes made pursuant to the formula-based adjustment mechanism authorized under this section, reduce, alter, or impair deferred fuel cost charges that are to be imposed, billed, charged, collected, and remitted for the benefit of the bondholders, any assignee, and any other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the related deferred fuel cost bonds have been paid and performed in full.

2. Any person that issues deferred fuel cost bonds may include the language specified in subdivision 1 in the deferred fuel cost bonds and related documentation.

K. An assignee or financing party shall not be considered an electric utility or person providing electric service by virtue of engaging in the transactions described in this section.

L. If there is a conflict between this section and any other law regarding the attachment, assignment, or perfection, or the effect of perfection, or priority of, assignment or transfer of, or security interest in deferred fuel cost property, this section shall govern.

M. In making determinations under this section, the Commission may engage an outside consultant and counsel.

N. If any provision of this section is held invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence shall not affect the validity of any action allowed under this section which is taken by an electric utility, an assignee, a financing party, a collection agent, or a party to an ancillary agreement, and any such action shall remain in full force and effect with respect to all deferred fuel cost bonds issued or authorized in a financing order issued under this section before the date that such provision is held invalid or is invalidated, superseded, replaced, or repealed, or expires for any reason.

O. As used in this section:

"Ancillary agreement" means a bond, insurance policy, letter of credit, reserve account, surety bond, interest rate lock or swap arrangement, hedging arrangement, liquidity or credit support arrangement, or other financial arrangement entered into in connection with deferred fuel cost bonds.

"Assignee" means a legally recognized entity to which an electric utility assigns, sells, or transfers, other than as a security, all or a portion of its interest in or right to deferred fuel cost property. "Assignee" includes a corporation, limited liability company, general partnership or limited partnership, public authority trust, financing entity, or other entity to which an assignee assigns, sells, or transfers, other than as a security, all or a portion of its interest in or right to deferred fuel cost property.

"Bondholder" means a person who holds a deferred fuel cost bond.

"Deferred fuel cost bonds" means bonds debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership, or other evidences of indebtedness or ownership that are issued in one or more series or tranches by an electric utility or its assignee pursuant to a financing order, the proceeds of which are used directly or indirectly to recover, finance, or refinance Commission-approved deferred fuel costs and financing costs, and that are secured by or payable from deferred fuel cost property. If certificates of participation or ownership are issued, references in this section to principal, interest, or premium shall be construed to refer to comparable amounts under those certificates.

"Deferred fuel cost charge" means the nonbypassable charges authorized by the Commission to repay, finance, or refinance deferred fuel costs and financing costs (i) imposed on and part of all retail customer bills, except those of exempt retail access customers; (ii) collected by an electric utility or its successor or assignees, or a collection agent, in full, separate and apart from the electric utility's base rates; and (iii) paid by all retail customers of the electric utility, irrespective of the generation supplier of such customer, except for an exempt retail access customer.

"Deferred fuel cost property" includes:

1. All rights and interests of an electric utility or successor or assignee of the electric utility under a financing order, including the right to impose, bill, charge, collect, and receive deferred fuel cost charges authorized under the financing order and to obtain periodic adjustments to such charges as provided in the financing order; and

2. All revenues, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in the financing order, regardless of whether such revenues, collections, claims, rights to payment, payments, money, or proceeds are imposed, billed, received,

collected, or maintained together with or commingled with other revenues, collections, rights to payment, payments, money, or proceeds.

"Deferred fuel costs" means the unrecovered amounts of previously incurred costs of fuel used to generate electricity, including the costs of purchased power, that have been deferred by an electric utility for future recovery from the utility's customers, along with financing costs on the utility's fuel deferral balance.

"Electric utility" means a Phase II Utility.

"Exempt retail access customer" means a retail customer of an electric utility that, pursuant to the provisions of § 56-577 or 56-577.1, purchased electric energy exclusively from a supplier of electric energy licensed to sell retail electric energy exclusively within the Commonwealth other than the electric utility for the entire period between July 1, 2021, and June 30, 2023.

"Financing costs" means:

1. Interest and any premium, including any acquisition, defeasance, or redemption premium, payable on deferred fuel cost bonds;

2. Any payment required under any indenture, ancillary agreement, or other financing documents pertaining to deferred fuel cost bonds and any amount required to fund or replenish a reserve account or other accounts established under the terms of any indenture, ancillary agreement, or other financing documents pertaining to deferred fuel cost bonds;

3. Any other costs related to structuring, offering, issuing, supporting, repaying, refunding, servicing, and complying with deferred fuel cost bonds, including service fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, structuring adviser fees, administrative fees, placement and underwriting fees, independent director and manager fees, capitalized interest, rating agency fees, stock exchange listing and compliance fees, security registration fees, filing fees, information technology programming costs, and any other costs necessary to otherwise ensure the timely payment of deferred fuel cost bonds or other amounts or charges payable in connection with the bonds, including costs related to obtaining the financing order;

4. Any taxes and license fees or other fees imposed on the revenues generated from the collection of deferred fuel cost charges or otherwise resulting from the collection of deferred fuel cost charges, in any such case whether paid, payable, or accrued;

5. Any state and local taxes, franchise, gross receipts, and other taxes or similar charges, including regulatory assessment fees, whether paid, payable, or accrued;

6. Any costs incurred by the Commission for any outside consultants or counsel retained in connection with the securitization of deferred fuel costs; and

7. Any financing costs on the utility's fuel deferral balance prior to issuance of any fuel cost bonds, calculated at the utility's approved weighted average cost of capital.

"Financing order" means an order that authorizes the issuance of deferred fuel cost bonds; the imposition, collection, and periodic adjustments of a deferred fuel cost charge; the creation of deferred fuel cost property; the sale, assignment, or transfer of deferred fuel cost property to an assignee and any other actions necessary or advisable to take actions described in the financing order.

"Financing party" means bondholders and trustees, collateral agents, any party under an ancillary agreement, or any other person acting for the benefit of bondholders.

"Financing statement" has the same meaning as provided in § 8.9A-102 of the Uniform Commercial Code.

"Phase II Utility" has the same meaning as provided in subdivision A 1 of § 56-585.1.

"Pledgee" means a financing party to which an electric utility or its successors or assignees mortgages, negotiates, pledges, or creates a security interest or lien on all or any portion of its interest in or right to deferred fuel cost property.

§ 56-581. Regulation of rates subject to Commission's jurisdiction.

A. ~~After the expiration or termination of capped rates except as provided in § 56-585.1, the~~ *The* Commission shall regulate the rates of investor-owned incumbent electric utilities for the transmission of electric energy, to the extent not prohibited by federal law, and for the generation of electric energy and the distribution of electric energy to retail customers pursuant to *this section and* § 56-585.1.

B. In any proceeding to review base rates for a Phase I Utility that commences after July 1, 2023, if the Commission determines in its sole discretion that the utility's existing base rates will, on a going-forward basis, either produce (i) revenues in excess of the utility's authorized rate of return or (ii) revenues below the utility's authorized rate of return, then, notwithstanding any provision of law governing rate proceedings, the Commission shall order any reductions or increases, as applicable and necessary, to such base rates that it deems appropriate to ensure the resulting base rates (a) are just and reasonable and (b) provide the utility an opportunity to recover its costs of providing services over the rate period ending on December 31 of the year of the utility's succeeding review and earn a fair rate of return authorized pursuant to the provisions governing such review proceeding. Such

determination shall be limited to the Phase I Utility's base rates and shall not consider the costs or revenues recovered in any rate adjustment clause authorized pursuant to this chapter.

C. In any proceeding to review base rates for a Phase II Utility that commences after July 1, 2023, if the Commission determines in its sole discretion that the utility's existing base rates will, on a going-forward basis, either produce (i) revenues in excess of the utility's authorized rate of return or (ii) revenues below the utility's authorized rate of return, then, notwithstanding any provision of subdivision A 8 of § 56-585.1, the Commission shall order any reductions or increases, as applicable and necessary, to such base rates that it deems appropriate to ensure the resulting base rates (a) are just and reasonable and (b) provide the utility an opportunity to recover its costs of providing services over the rate period ending on December 31 of the year of the utility's succeeding review and earn a fair rate of return on its base rates as determined in subdivision A 2 of § 56-585.1. Such determination shall be limited to the Phase II Utility's base rates and shall not consider the costs or revenues recovered in any rate adjustment clause authorized pursuant to subdivision A 6 of § 56-585.1 that has not been combined with the utility's base rates. The Commission shall use the most recently ended 12-month test period, along with normalization of nonrecurring test period costs and annualized adjustments for future costs, as the basis for determining the appropriateness of any rate adjustment. In any such filing to review base rates, a Phase II Utility shall separately project future costs over each 12-month period ending on December 31 of the year of the utility's succeeding review period. The Commission may, to the extent it finds such action aligns with the utility's projected cost of service, direct that any reduction or increase to the utility's rates for generation and distribution services be implemented on a staggered basis at the commencement and midpoint of the succeeding rate period.

~~B.~~ *D.* Beginning July 1, 1999, and thereafter, no cooperative that was a member of a power supply cooperative on January 1, 1999, shall be obligated to file any rate rider as a consequence of an increase or decrease in the rates, other than fuel costs, of its wholesale supplier, nor must any adjustment be made to such cooperative's rates as a consequence thereof.

~~C.~~ *E.* Except for the provision of default services under § 56-585 or emergency services in § 56-586, nothing in this chapter shall authorize the Commission to regulate the rates or charges for electric service to the Commonwealth and its municipalities.

F. As used in this section:

"Base rates" means rates for generation and distribution services.

"Phase I Utility" has the same meaning as provided in subdivision A 1 of § 56-585.1.

"Phase II Utility" has the same meaning as provided in subdivision A 1 of § 56-585.1.

§ 56-585.1. Generation, distribution, and transmission rates after capped rates terminate or expire.

A. During the first six months of 2009, the Commission shall, after notice and opportunity for hearing, initiate proceedings to review the rates, terms and conditions for the provision of generation, distribution and transmission services of each investor-owned incumbent electric utility. Such proceedings shall be governed by the provisions of Chapter 10 (§ 56-232 et seq.), except as modified herein. In such proceedings the Commission shall determine fair rates of return on common equity applicable to the generation and distribution services of the utility. In so doing, the Commission may use any methodology to determine such return it finds consistent with the public interest, but such return shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility, nor shall the Commission set such return more than 300 basis points higher than such average. The peer group of the utility shall be determined in the manner prescribed in subdivision 2 b. The Commission may increase or decrease such combined rate of return by up to 100 basis points based on the generating plant performance, customer service, and operating efficiency of a utility, as compared to nationally recognized standards determined by the Commission to be appropriate for such purposes. In such a proceeding, the Commission shall determine the rates that the utility may charge until such rates are adjusted. If the Commission finds that the utility's combined rate of return on common equity is more than 50 basis points below the combined rate of return as so determined, it shall be authorized to order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn not less than such combined rate of return. If the Commission finds that the utility's combined rate of return on common equity is more than 50 basis points above the combined rate of return as so determined, it shall be authorized either (i) to order reductions to the utility's rates it finds appropriate, provided that the Commission may not order such rate reduction unless it finds that the resulting rates will provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than the fair rates of return on common equity applicable to the generation and distribution services; or (ii) to direct that 60 percent of the amount of the utility's earnings that were more than 50 basis points above

the fair combined rate of return for calendar year 2008 be credited to customers' bills, in which event such credits shall be amortized over a period of six to 12 months, as determined at the discretion of the Commission, following the effective date of the Commission's order and be allocated among customer classes such that the relationship between the specific customer class rates of return to the overall target rate of return will have the same relationship as the last approved allocation of revenues used to design base rates. Commencing in 2011, the Commission, after notice and opportunity for hearing, shall conduct reviews of the rates, terms and conditions for the provision of generation, distribution and transmission services by each investor-owned incumbent electric utility, subject to the following provisions:

1. Rates, terms and conditions for each service shall be reviewed separately on an unbundled basis, and such reviews shall be conducted in a single, combined proceeding. Pursuant to subsection A of § 56-585.1:1, the Commission shall conduct a review for a Phase I Utility in 2020, utilizing the three successive 12-month test periods beginning January 1, 2017, and ending December 31, 2019. Thereafter, reviews for a Phase I Utility will be on a triennial basis with subsequent proceedings utilizing the three successive 12-month test periods ending December 31 immediately preceding the year in which such review proceeding is conducted. Pursuant to subsection A of § 56-585.1:1, the Commission shall conduct a review for a Phase II Utility in 2021, utilizing the four successive 12-month test periods beginning January 1, 2017, and ending December 31, 2020, with subsequent reviews on a ~~triennial~~ *biennial* basis *commencing in 2023, with such proceedings* utilizing the ~~three~~ *two* successive 12-month test periods ending December 31 immediately preceding the year in which such review proceeding is conducted. ~~All such reviews occurring after December 31, 2017, shall be referred to as triennial reviews.~~ For purposes of this section, a Phase I Utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a Phase II Utility is an investor-owned incumbent electric utility that was bound by such a settlement.

2. Subject to the provisions of subdivision 6, the fair rate of return on common equity applicable separately to the generation and distribution services of such utility, and for the two such services combined, and for any rate adjustment clauses approved under subdivision 5 or 6, shall be determined by the Commission during each such ~~triennial~~ review, as follows:

a. The Commission may use any methodology to determine such return it finds consistent with the public interest~~, but~~. *However, for a Phase I Utility,* for applications received by the Commission on or after January 1, 2020, such return shall not be set lower than the average of either (i) the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility subject to such triennial review or (ii) the authorized returns on common equity that are set by the applicable regulatory commissions for the same selected peer group, nor shall the Commission set such return more than 150 basis points higher than such average.

b. ~~In~~ *For a Phase I Utility, in* selecting such majority of peer group investor-owned electric utilities for applications received by the Commission on or after January 1, 2020, the Commission shall first remove from such group the two utilities within such group that have the lowest reported or authorized, as applicable, returns of the group, as well as the two utilities within such group that have the highest reported or authorized, as applicable, returns of the group, and the Commission shall then select a majority of the utilities remaining in such peer group. In its final order regarding such triennial review, the Commission shall identify the utilities in such peer group it selected for the calculation of such limitation. ~~For~~ *With respect to a Phase I Utility, for* purposes of this subdivision *2*, an investor-owned electric utility shall be deemed part of such peer group if (i) its principal operations are conducted in the southeastern United States east of the Mississippi River in either the states of West Virginia or Kentucky or in those states south of Virginia, excluding the state of Tennessee, (ii) it is a vertically-integrated electric utility providing generation, transmission, and distribution services whose facilities and operations are subject to state public utility regulation in the state where its principal operations are conducted, (iii) it had a long-term bond rating assigned by Moody's Investors Service of at least Baa at the end of the most recent test period subject to such ~~triennial~~ review, and (iv) it is not an affiliate of the utility subject to such ~~triennial~~ review *or a utility whose fair rate of return on common equity is determined by the Commission*.

c. The Commission may~~, consistent with its precedent for incumbent electric utilities prior to the enactment of Chapters 888 and 933 of the Acts of Assembly of 2007,~~ increase or decrease the utility's combined rate of return ~~based on the Commission's consideration of the utility's performance~~ *for generation and distribution services by up to 50 basis points based on factors that may include, reliability, generating plant performance, customer service, operating efficiency of a utility, and load forecasting. Any such adjustment to the combined rate of return for generation and distribution services*

shall include consideration of nationally recognized standards determined by the Commission to be appropriate for such purposes.

d. In any Current Proceeding, the Commission shall determine whether the Current Return has increased, on a percentage basis, above the Initial Return by more than the increase, expressed as a percentage, in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, since the date on which the Commission determined the Initial Return. If so, the Commission may conduct an additional analysis of whether it is in the public interest to utilize such Current Return for the Current Proceeding then pending. A finding of whether the Current Return justifies such additional analysis shall be made without regard to any enhanced rate of return on common equity awarded pursuant to the provisions of subdivision 6. Such additional analysis shall include, but not be limited to, a consideration of overall economic conditions, the level of interest rates and cost of capital with respect to business and industry, in general, as well as electric utilities, the current level of inflation and the utility's cost of goods and services, the effect on the utility's ability to provide adequate service and to attract capital if less than the Current Return were utilized for the Current Proceeding then pending, and such other factors as the Commission may deem relevant. If, as a result of such analysis, the Commission finds that use of the Current Return for the Current Proceeding then pending would not be in the public interest, then the lower limit imposed by subdivision 2 a on the return to be determined by the Commission for such utility shall be calculated, for that Current Proceeding only, by increasing the Initial Return by a percentage at least equal to the increase, expressed as a percentage, in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, since the date on which the Commission determined the Initial Return. For purposes of this subdivision:

"Current Proceeding" means any proceeding conducted under any provisions of this subsection that require or authorize the Commission to determine a fair combined rate of return on common equity for a utility and that will be concluded after the date on which the Commission determined the Initial Return for such utility.

"Current Return" means the minimum fair combined rate of return on common equity required for any Current Proceeding by the limitation regarding a utility's peer group specified in subdivision 2 a.

"Initial Return" means the fair combined rate of return on common equity determined for such utility by the Commission on the first occasion after July 1, 2009, under any provision of this subsection pursuant to the provisions of subdivision 2 a.

e. In addition to other considerations, in setting the return on equity within the range allowed by this section, the Commission shall strive to maintain costs of retail electric energy that are cost competitive with costs of retail electric energy provided by the other peer group investor-owned electric utilities.

f. The determination of such returns shall be made by the Commission on a stand-alone basis, and specifically without regard to any return on common equity or other matters determined with regard to facilities described in subdivision 6.

g. If the combined rate of return on common equity earned by the generation and distribution services is no more than 50 basis points above or below the return as so determined or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, such return is no more than 70 basis points above or below the return as so determined, such combined return shall not be considered either excessive or insufficient, respectively. However, for any test period commencing after December 31, 2012, for a Phase II Utility, and after December 31, 2013, for a Phase I Utility, if the utility has, during the test period or periods under review, earned below the return as so determined, whether or not such combined return is within 70 basis points of the return as so determined, the utility may petition the Commission for approval of an increase in rates in accordance with the provisions of subdivision 8 a as if it had earned more than 70 basis points below a fair combined rate of return, and such proceeding shall otherwise be conducted in accordance with the provisions of this section. The provisions of this subdivision are subject to the provisions of subdivision 8.

h. Any amount of a utility's earnings directed by the Commission to be credited to customers' bills pursuant to this section shall not be considered for the purpose of determining the utility's earnings in any subsequent ~~triennial~~ review.

3. Each such utility shall make a triennial filing by March 31 of every third year, with such filings commencing for a Phase I Utility in 2020, and such filings commencing for a Phase II Utility in 2021~~, consisting of the schedules contained in the Commission's rules governing utility rate increase applications~~ *and terminating thereafter*. Such filing shall encompass the three successive 12-month test periods ending December 31 immediately preceding the year in which such proceeding is conducted, except that the filing for a Phase II Utility in 2021 shall encompass the four successive 12-month test periods ending December 31, 2020. *After 2021, each Phase II Utility shall make a biennial filing by*

March 31 of every second year, except that the 2023 filing for a Phase II Utility shall be made on or after July 1, 2023. All biennial filings shall encompass the two successive 12-month test periods ending December 31 immediately preceding the year in which such review proceeding is conducted. All such filings shall consist of the schedules contained in the Commission's rules governing utility rate increase applications, and in every such case the filing for each year shall be identified separately and shall be segregated from any other year encompassed by the filing. *In a filing under this subdivision that does not result in an overall rate change, a utility may propose an adjustment to one or more tariffs that are revenue neutral to the utility.*

If the Commission determines that rates should be revised or credits be applied to customers' bills pursuant to subdivision 8 or ~~9~~ *10*, any rate adjustment clauses previously implemented related to facilities utilizing simple-cycle combustion turbines described in subdivision 6, shall be combined with the utility's costs, revenues, and investments until the amounts that are the subject of such rate adjustment clauses are fully recovered. The Commission shall combine such clauses with the utility's costs, revenues, and investments only after it makes its initial determination with regard to necessary rate revisions or credits to customers' bills, and the amounts thereof, but after such clauses are combined as ~~herein~~ specified *in this paragraph*, they shall thereafter be considered part of the utility's costs, revenues, and investments for the purposes of future ~~triennial~~ review proceedings. ~~In a triennial filing under this subdivision that does not result in an overall rate change a utility may propose an adjustment to one or more tariffs that are revenue neutral to the utility.~~

As of July 1, 2023, a Phase II Utility shall select a subset of rate adjustment clauses previously implemented pursuant to subdivision 5 or 6 having a combined annual revenue requirement, as of July 1, 2023, of at least $350 million and combine such rate adjustment clauses with the utility's costs, revenues, and investments for generation and distribution services. After such rate adjustment clauses are combined as specified in this paragraph, such rate adjustment clauses shall be considered part of the utility's costs, revenues, and investments for the purposes of future biennial review proceedings, and the combination of such rate adjustment clauses shall be specifically subject to audit by the Commission in the utility's 2023 biennial review filing. Notwithstanding the provisions of subsection C of § 56-581, such combination shall not serve as the basis for an increase in a Phase II Utility's rates for generation and distribution services in its 2023 biennial proceeding.

4. (Expires December 31, 2023) The following costs incurred by the utility shall be deemed reasonable and prudent: (i) costs for transmission services provided to the utility by the regional transmission entity of which the utility is a member, as determined under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission; (ii) costs charged to the utility that are associated with demand response programs approved by the Federal Energy Regulatory Commission and administered by the regional transmission entity of which the utility is a member; and (iii) costs incurred by the utility to construct, operate, and maintain transmission lines and substations installed in order to provide service to a business park. Upon petition of a utility at any time after the expiration or termination of capped rates, but not more than once in any 12-month period, the Commission shall approve a rate adjustment clause under which such costs, including, without limitation, costs for transmission service; charges for new and existing transmission facilities, including costs incurred by the utility to construct, operate, and maintain transmission lines and substations installed in order to provide service to a business park; administrative charges; and ancillary service charges designed to recover transmission costs, shall be recovered on a timely and current basis from customers. Retail rates to recover these costs shall be designed using the appropriate billing determinants in the retail rate schedules.

4. (Effective January 1, 2024) The following costs incurred by the utility shall be deemed reasonable and prudent: (i) costs for transmission services provided to the utility by the regional transmission entity of which the utility is a member, as determined under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission, and (ii) costs charged to the utility that are associated with demand response programs approved by the Federal Energy Regulatory Commission and administered by the regional transmission entity of which the utility is a member. Upon petition of a utility at any time after the expiration or termination of capped rates, but not more than once in any 12-month period, the Commission shall approve a rate adjustment clause under which such costs, including, without limitation, costs for transmission service, charges for new and existing transmission facilities, administrative charges, and ancillary service charges designed to recover transmission costs, shall be recovered on a timely and current basis from customers. Retail rates to recover these costs shall be designed using the appropriate billing determinants in the retail rate schedules.

5. A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of the following costs:

a. Incremental costs described in clause (vi) of subsection B of § 56-582 incurred between July 1,

2004, and the expiration or termination of capped rates, if such utility is, as of July 1, 2007, deferring such costs consistent with an order of the Commission entered under clause (vi) of subsection B of § 56-582. The Commission shall approve such a petition allowing the recovery of such costs that comply with the requirements of clause (vi) of subsection B of § 56-582;

b. Projected and actual costs for the utility to design and operate fair and effective peak-shaving programs or pilot programs. The Commission shall approve such a petition if it finds that the program is in the public interest, provided that the Commission shall allow the recovery of such costs as it finds are reasonable;

c. Projected and actual costs for the utility to design, implement, and operate energy efficiency programs or pilot programs. Any such petition shall include a proposed budget for the design, implementation, and operation of the energy efficiency program, including anticipated savings from and spending on each program, and the Commission shall grant a final order on such petitions within eight months of initial filing. The Commission shall only approve such a petition if it finds that the program is in the public interest. If the Commission determines that an energy efficiency program or portfolio of programs is not in the public interest, its final order shall include all work product and analysis conducted by the Commission's staff in relation to that program that has bearing upon the Commission's determination. Such order shall adhere to existing protocols for extraordinarily sensitive information.

Energy efficiency pilot programs are in the public interest provided that the pilot program is (i) of limited scope, cost, and duration and (ii) intended to determine whether a new or substantially revised program would be cost-effective.

Prior to January 1, 2022, the Commission shall award a margin for recovery on operating expenses for energy efficiency programs and pilot programs, which margin shall be equal to the general rate of return on common equity determined as described in subdivision 2. Beginning January 1, 2022, and thereafter, if the Commission determines that the utility meets in any year the annual energy efficiency standards set forth in § 56-596.2, in the following year, the Commission shall award a margin on energy efficiency program operating expenses in that year, to be recovered through a rate adjustment clause, which margin shall be equal to the general rate of return on common equity determined as described in subdivision 2. If the Commission does not approve energy efficiency programs that, in the aggregate, can achieve the annual energy efficiency standards, the Commission shall award a margin on energy efficiency operating expenses in that year for any programs the Commission has approved, to be recovered through a rate adjustment clause under this subdivision, which margin shall equal the general rate of return on common equity determined as described in subdivision 2. Any margin awarded pursuant to this subdivision shall be applied as part of the utility's next rate adjustment clause true-up proceeding. The Commission shall also award an additional 20 basis points for each additional incremental 0.1 percent in annual savings in any year achieved by the utility's energy efficiency programs approved by the Commission pursuant to this subdivision, beyond the annual requirements set forth in § 56-596.2, provided that the total performance incentive awarded in any year shall not exceed 10 percent of that utility's total energy efficiency program spending in that same year.

The Commission shall annually monitor and report to the General Assembly the performance of all programs approved pursuant to this subdivision, including each utility's compliance with the total annual savings required by § 56-596.2, as well as the annual and lifecycle net and gross energy and capacity savings, related emissions reductions, and other quantifiable benefits of each program; total customer bill savings that the programs produce; utility spending on each program, including any associated administrative costs; and each utility's avoided costs and cost-effectiveness results.

Notwithstanding any other provision of law, unless the Commission finds in its discretion and after consideration of all in-state and regional transmission entity resources that there is a threat to the reliability or security of electric service to the utility's customers, the Commission shall not approve construction of any new utility-owned generating facilities that emit carbon dioxide as a by-product of combusting fuel to generate electricity unless the utility has already met the energy savings goals identified in § 56-596.2 and the Commission finds that supply-side resources are more cost-effective than demand-side or energy storage resources.

As used in this subdivision, "large general service customer" means a customer that has a verifiable history of having used more than one megawatt of demand from a single site.

Large general service customers shall be exempt from requirements that they participate in energy efficiency programs if the Commission finds that the large general service customer has, at the customer's own expense, implemented energy efficiency programs that have produced or will produce measured and verified results consistent with industry standards and other regulatory criteria stated in this section. The Commission shall, no later than June 30, 2021, adopt rules or regulations (a) establishing the process for large general service customers to apply for such an exemption, (b) establishing the administrative procedures by which eligible customers will notify the utility, and (c) defining the standard criteria that shall be satisfied by an applicant in order to notify the utility,

including means of evaluation measurement and verification and confidentiality requirements. At a minimum, such rules and regulations shall require that each exempted large general service customer certify to the utility and Commission that its implemented energy efficiency programs have delivered measured and verified savings within the prior five years. In adopting such rules or regulations, the Commission shall also specify the timing as to when a utility shall accept and act on such notice, taking into consideration the utility's integrated resource planning process, as well as its administration of energy efficiency programs that are approved for cost recovery by the Commission. Savings from large general service customers shall be accounted for in utility reporting in the standards in § 56-596.2.

The notice of nonparticipation by a large general service customer shall be for the duration of the service life of the customer's energy efficiency measures. The Commission may on its own motion initiate steps necessary to verify such nonparticipant's achievement of energy efficiency if the Commission has a body of evidence that the nonparticipant has knowingly misrepresented its energy efficiency achievement.

A utility shall not charge such large general service customer for the costs of installing energy efficiency equipment beyond what is required to provide electric service and meter such service on the customer's premises if the customer provides, at the customer's expense, equivalent energy efficiency equipment. In all relevant proceedings pursuant to this section, the Commission shall take into consideration the goals of economic development, energy efficiency and environmental protection in the Commonwealth;

d. Projected and actual costs of compliance with renewable energy portfolio standard requirements pursuant to § 56-585.5 that are not recoverable under subdivision 6. The Commission shall approve such a petition allowing the recovery of such costs incurred as required by § 56-585.5, provided that the Commission does not otherwise find such costs were unreasonably or imprudently incurred;

e. Projected and actual costs of projects that the Commission finds to be necessary to mitigate impacts to marine life caused by construction of offshore wind generating facilities, as described in § 56-585.1:11, or to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the costs of allowances purchased through a market-based trading program for carbon dioxide emissions. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations;

f. Projected and actual costs, not currently in rates, for the utility to design, implement, and operate programs approved by the Commission that accelerate the vegetation management of distribution rights-of-way. No costs shall be allocated to or recovered from customers that are served within the large general service rate classes for a Phase II Utility or that are served at subtransmission or transmission voltage, or take delivery at a substation served from subtransmission or transmission voltage, for a Phase I Utility; and

g. Projected and actual costs, not currently in rates, for the utility to design, implement, and operate programs approved by the Commission to provide incentives to (i) low-income, elderly, and disabled individuals or (ii) organizations providing residential services to low-income, elderly, and disabled individuals for the installation of, or access to, equipment to generate electric energy derived from sunlight, provided the low-income, elderly, and disabled individuals, or organizations providing residential services to low-income, elderly, and disabled individuals, first participate in incentive programs for the installation of measures that reduce heating or cooling costs.

Any rate adjustment clause approved under subdivision 5 c by the Commission shall remain in effect until the utility exhausts the approved budget for the energy efficiency program. The Commission shall have the authority to determine the duration or amortization period for any other rate adjustment clause approved under this subdivision.

6. To ensure the generation and delivery of a reliable and adequate supply of electricity, to meet the utility's projected native load obligations and to promote economic development, a utility may at any time, after the expiration or termination of capped rates, petition the Commission for approval of a rate adjustment clause for recovery on a timely and current basis from customers of the costs of (i) a coal-fueled generation facility that utilizes Virginia coal and is located in the coalfield region of the Commonwealth as described in § 15.2-6002, regardless of whether such facility is located within or without the utility's service territory, (ii) one or more other generation facilities, (iii) one or more major unit modifications of generation facilities, including the costs of any system or equipment upgrade, system or equipment replacement, or other cost reasonably appropriate to extend the combined operating license for or the operating life of one or more generation facilities utilizing nuclear power, (iv) one or more new underground facilities to replace one or more existing overhead distribution facilities of 69 kilovolts or less located within the Commonwealth, (v) one or more pumped hydroelectricity generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source and such facilities and associated resources are located in the coalfield region of the

Commonwealth as described in § 15.2-6002, regardless of whether such facility is located within or without the utility's service territory, or (vi) one or more electric distribution grid transformation projects; however, subject to the provisions of the following sentence, the utility shall not file a petition under clause (iv) more often than annually and, in such petition, shall not seek any annual incremental increase in the level of investments associated with such a petition that exceeds five percent of such utility's distribution rate base, as such rate base was determined for the most recently ended 12-month test period in the utility's latest review proceeding conducted pursuant to subdivision 3 and concluded by final order of the Commission prior to the date of filing of such petition under clause (iv). In all proceedings regarding petitions filed under clause (iv) or (vi), the level of investments approved for recovery in such proceedings shall be in addition to, and not in lieu of, levels of investments previously approved for recovery in prior proceedings under clause (iv) or (vi), as applicable. As of December 1, 2028, any costs recovered by a utility pursuant to clause (iv) shall be limited to any remaining costs associated with conversions of overhead distribution facilities to underground facilities that have been previously approved or are pending approval by the Commission through a petition by the utility under this subdivision. Such a petition concerning facilities described in clause (ii) that utilize nuclear power, facilities described in clause (ii) that are coal-fueled and will be built by a Phase I Utility, or facilities described in clause (i) may also be filed before the expiration or termination of capped rates. A utility that constructs or makes modifications to any such facility, or purchases any facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, shall have the right to recover the costs of the facility, as accrued against income, through its rates, including projected construction work in progress, and any associated allowance for funds used during construction, planning, development and construction or acquisition costs, life-cycle costs, costs related to assessing the feasibility of potential sites for new underground facilities, and costs of infrastructure associated therewith, plus, as an incentive to undertake such projects, an enhanced rate of return on common equity calculated as specified below; however, in determining the amounts recoverable under a rate adjustment clause for new underground facilities, the Commission shall not consider, or increase or reduce such amounts recoverable because of (a) the operation and maintenance costs attributable to either the overhead distribution facilities being replaced or the new underground facilities or (b) any other costs attributable to the overhead distribution facilities being replaced. Notwithstanding the preceding sentence, the costs described in clauses (a) and (b) thereof shall remain eligible for recovery from customers through the utility's base rates for distribution service. A utility filing a petition for approval to construct or purchase a facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses may propose a rate adjustment clause based on a market index in lieu of a cost of service model for such facility. A utility seeking approval to construct or purchase a generating facility that emits carbon dioxide shall demonstrate that it has already met the energy savings goals identified in § 56-596.2 and that the identified need cannot be met more affordably through the deployment or utilization of demand-side resources or energy storage resources and that it has considered and weighed alternative options, including third-party market alternatives, in its selection process.

The costs of the facility, other than return on projected construction work in progress and allowance for funds used during construction, shall not be recovered prior to the date a facility constructed by the utility and described in clause (i), (ii), (iii), or (v) begins commercial operation, the date the utility becomes the owner of a purchased generation facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, or the date new underground facilities are classified by the utility as plant in service. In any application to construct a new generating facility, the utility shall include, and the Commission shall consider, the social cost of carbon, as determined by the Commission, as a benefit or cost, whichever is appropriate. The Commission shall ensure that the development of new, or expansion of existing, energy resources or facilities does not have a disproportionate adverse impact on historically economically disadvantaged communities. The Commission may adopt any rules it deems necessary to determine the social cost of carbon and shall use the best available science and technology, including the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, published by the Interagency Working Group on Social Cost of Greenhouse Gases from the United States Government in August 2016, as guidance. The Commission shall include a system to adjust the costs established in this section with inflation.

Such enhanced rate of return on common equity shall be applied to allowance for funds used during construction and to construction work in progress during the construction phase of the facility and shall thereafter be applied to the entire facility during the first portion of the service life of the facility. The

first portion of the service life shall be as specified in the table below; however, the Commission shall determine the duration of the first portion of the service life of any facility, within the range specified in the table below, which determination shall be consistent with the public interest and shall reflect the Commission's determinations regarding how critical the facility may be in meeting the energy needs of the citizens of the Commonwealth and the risks involved in the development of the facility. After the first portion of the service life of the facility is concluded, the utility's general rate of return shall be applied to such facility for the remainder of its service life. As used herein, the service life of the facility shall be deemed to begin on the date a facility constructed by the utility and described in clause (i), (ii), (iii), or (v) begins commercial operation, the date the utility becomes the owner of a purchased generation facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, or the date new underground facilities or new electric distribution grid transformation projects are classified by the utility as plant in service, and such service life shall be deemed equal in years to the life of that facility as used to calculate the utility's depreciation expense. Such enhanced rate of return on common equity shall be calculated by adding the basis points specified in the table below to the utility's general rate of return, and such enhanced rate of return shall apply only to the facility that is the subject of such rate adjustment clause. Allowance for funds used during construction shall be calculated for any such facility utilizing the utility's actual capital structure and overall cost of capital, including an enhanced rate of return on common equity as determined pursuant to this subdivision, until such construction work in progress is included in rates. The construction of any facility described in clause (i) or (v) is in the public interest, and in determining whether to approve such facility, the Commission shall liberally construe the provisions of this title. The construction or purchase by a utility of one or more generation facilities with at least one megawatt of generating capacity, and with an aggregate rated capacity that does not exceed 16,100 megawatts, including rooftop solar installations with a capacity of not less than 50 kilowatts, and with an aggregate capacity of 100 megawatts, that use energy derived from sunlight or from onshore wind and are located in the Commonwealth or off the Commonwealth's Atlantic shoreline, regardless of whether any of such facilities are located within or without the utility's service territory, is in the public interest, and in determining whether to approve such facility, the Commission shall liberally construe the provisions of this title. A utility may enter into short-term or long-term power purchase contracts for the power derived from sunlight generated by such generation facility prior to purchasing the generation facility. The replacement of any subset of a utility's existing overhead distribution tap lines that have, in the aggregate, an average of nine or more total unplanned outage events-per-mile over a preceding 10-year period with new underground facilities in order to improve electric service reliability is in the public interest. In determining whether to approve petitions for rate adjustment clauses for such new underground facilities that meet this criteria, and in determining the level of costs to be recovered thereunder, the Commission shall liberally construe the provisions of this title.

The conversion of any such facilities on or after September 1, 2016, is deemed to provide local and system-wide benefits and to be cost beneficial, and the costs associated with such new underground facilities are deemed to be reasonably and prudently incurred and, notwithstanding the provisions of subsection C or D, shall be approved for recovery by the Commission pursuant to this subdivision, provided that the total costs associated with the replacement of any subset of existing overhead distribution tap lines proposed by the utility with new underground facilities, exclusive of financing costs, shall not exceed an average cost per customer of $20,000, with such customers, including those served directly by or downline of the tap lines proposed for conversion, and, further, such total costs shall not exceed an average cost per mile of tap lines converted, exclusive of financing costs, of $750,000. A utility shall, without regard for whether it has petitioned for any rate adjustment clause pursuant to clause (vi), petition the Commission, not more than once annually, for approval of a plan for electric distribution grid transformation projects. Any plan for electric distribution grid transformation projects shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security. In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the costs associated with such projects will be recovered through a rate adjustment clause under this subdivision or through the utility's rates for generation and distribution services; and without regard to whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision 8 d. The Commission's final order regarding any such petition for approval of an electric distribution grid transformation plan shall be entered by the Commission not more than six months after the date of filing such petition. The Commission shall likewise enter its final order with respect to any petition by a utility for a certificate to construct and operate a generating facility or facilities utilizing energy derived

from sunlight, pursuant to subsection D of § 56-580, within six months after the date of filing such petition. The basis points to be added to the utility's general rate of return to calculate the enhanced rate of return on common equity, and the first portion of that facility's service life to which such enhanced rate of return shall be applied, shall vary by type of facility, as specified in the following table:

Type of Generation Facility	Basis Points	First Portion of Service Life
Nuclear-powered	200	Between 12 and 25 years
Carbon capture compatible, clean-coal powered	200	Between 10 and 20 years
Renewable powered, other than landfill gas powered	200	Between 5 and 15 years
Coalbed methane gas powered	150	Between 5 and 15 years
Landfill gas powered	200	Between 5 and 15 years
Conventional coal or combined-cycle combustion turbine	100	Between 10 and 20 years

Only those facilities as to which a rate adjustment clause under this subdivision has been previously approved by the Commission, or as to which a petition for approval of such rate adjustment clause was filed with the Commission, on or before January 1, 2013, shall be entitled to the enhanced rate of return on common equity as specified in the above table during the construction phase of the facility and the approved first portion of its service life.

Thirty percent of all costs of such a facility utilizing nuclear power that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by the Commission in the test periods under review in the utility's next review filed after July 1, 2014. Thirty percent of all costs of a facility utilizing energy derived from offshore wind that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by the Commission in the test periods under review in the utility's next review filed after July 1, 2014.

In connection with planning to meet forecasted demand for electric generation supply and assure the adequate and sufficient reliability of service, consistent with § 56-598, planning and development activities for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from onshore or offshore wind are in the public interest.

Notwithstanding any provision of Chapter 296 of the Acts of Assembly of 2018, construction, purchasing, or leasing activities for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from onshore wind with an aggregate capacity of 16,100 megawatts, including rooftop solar installations with a capacity of not less than 50 kilowatts, and with an aggregate capacity of 100 megawatts, together with a utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore wind with an aggregate capacity of not more than 3,000 megawatts, are in the public interest. Additionally, energy storage facilities with an aggregate capacity of 2,700 megawatts are in the public interest. To the extent that a utility elects to recover the costs of any such new generation or energy storage facility or facilities through its rates for generation and distribution services and does not petition and receive approval from the Commission for recovery of such costs through a rate adjustment clause described in clause (ii), the Commission shall, upon the request of the utility in a ~~triennial~~ review proceeding, provide for a customer credit reinvestment offset, as applicable, pursuant to subdivision 8 d with respect to all costs deemed reasonable and prudent by the Commission in a proceeding pursuant to subsection D of § 56-580 or in a ~~triennial~~ review proceeding.

Electric distribution grid transformation projects are in the public interest. To the extent that a utility elects to recover the costs of such electric distribution grid transformation projects through its rates for generation and distribution services, and does not petition and receive approval from the Commission for recovery of such costs through a rate adjustment clause described in clause (vi), the Commission shall, upon the request of the utility in a ~~triennial~~ review proceeding, provide for a customer credit reinvestment offset, as applicable, pursuant to subdivision 8 d with respect to all costs deemed reasonable and prudent by the Commission in a proceeding for approval of a plan for electric

distribution grid transformation projects pursuant to subdivision 6 or in a ~~triennial~~ review proceeding.

Neither generation facilities described in clause (ii) that utilize simple-cycle combustion turbines nor new underground facilities shall receive an enhanced rate of return on common equity as described herein, but instead shall receive the utility's general rate of return during the construction phase of the facility and, thereafter, for the entire service life of the facility. No rate adjustment clause for new underground facilities shall allocate costs to, or provide for the recovery of costs from, customers that are served within the large power service rate class for a Phase I Utility and the large general service rate classes for a Phase II Utility. New underground facilities are hereby declared to be ordinary extensions or improvements in the usual course of business under the provisions of § 56-265.2.

As used in this subdivision, a generation facility is (1) "coalbed methane gas powered" if the facility is fired at least 50 percent by coalbed methane gas, as such term is defined in § 45.2-1600, produced from wells located in the Commonwealth, and (2) "landfill gas powered" if the facility is fired by methane or other combustible gas produced by the anaerobic digestion or decomposition of biodegradable materials in a solid waste management facility licensed by the Waste Management Board. A landfill gas powered facility includes, in addition to the generation facility itself, the equipment used in collecting, drying, treating, and compressing the landfill gas and in transmitting the landfill gas from the solid waste management facility where it is collected to the generation facility where it is combusted.

For purposes of this subdivision, "general rate of return" means the fair combined rate of return on common equity as it is determined by the Commission for such utility pursuant to subdivision 2.

Notwithstanding any other provision of this subdivision, if the Commission finds during the triennial review conducted for a Phase II Utility in 2021 that such utility has not filed applications for all necessary federal and state regulatory approvals to construct one or more nuclear-powered or coal-fueled generation facilities that would add a total capacity of at least 1500 megawatts to the amount of the utility's generating resources as such resources existed on July 1, 2007, or that, if all such approvals have been received, that the utility has not made reasonable and good faith efforts to construct one or more such facilities that will provide such additional total capacity within a reasonable time after obtaining such approvals, then the Commission, if it finds it in the public interest, may reduce on a prospective basis any enhanced rate of return on common equity previously applied to any such facility to no less than the general rate of return for such utility and may apply no less than the utility's general rate of return to any such facility for which the utility seeks approval in the future under this subdivision.

Notwithstanding any other provision of this subdivision, if a Phase II utility obtains approval from the Commission of a rate adjustment clause pursuant to subdivision 6 associated with a test or demonstration project involving a generation facility utilizing energy from offshore wind, and such utility has not, as of July 1, 2023, commenced construction as defined for federal income tax purposes of an offshore wind generation facility or facilities with a minimum aggregate capacity of 250 megawatts, then the Commission, if it finds it in the public interest, may direct that the costs associated with any such rate adjustment clause involving said test or demonstration project shall thereafter no longer be recovered through a rate adjustment clause pursuant to subdivision 6 and shall instead be recovered through the utility's rates for generation and distribution services, with no change in such rates for generation and distribution services as a result of the combination of such costs with the other costs, revenues, and investments included in the utility's rates for generation and distribution services. Any such costs shall remain combined with the utility's other costs, revenues, and investments included in its rates for generation and distribution services until such costs are fully recovered.

7. Any petition filed pursuant to subdivision 4, 5, or 6 shall be considered by the Commission on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility. Any costs incurred by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to subdivision 5 a, or that are related to facilities and projects described in clause (i) of subdivision 6, or that are related to new underground facilities described in clause (iv) of subdivision 6, shall be deferred on the books and records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Except as otherwise provided in subdivision 6, any costs prudently incurred on or after July 1, 2007, by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to facilities and projects described in clause (ii) or clause (iii) of subdivision 6 that utilize nuclear power, or coal-fueled facilities and projects described in clause (ii) of subdivision 6 if such coal-fueled facilities will be built by a Phase I Utility, shall be deferred on the books and records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Any costs prudently incurred after the expiration or termination of capped rates related to other matters described

in subdivision 4, 5, or 6 shall be deferred beginning only upon the expiration or termination of capped rates, provided, however, that no provision of this act shall affect the rights of any parties with respect to the rulings of the Federal Energy Regulatory Commission in PJM Interconnection LLC and Virginia Electric and Power Company, 109 F.E.R.C. P 61,012 (2004). A utility shall establish a regulatory asset for regulatory accounting and ratemaking purposes under which it shall defer its operation and maintenance costs incurred in connection with (i) the refueling of any nuclear-powered generating plant and (ii) other work at such plant normally performed during a refueling outage. The utility shall amortize such deferred costs over the refueling cycle, but in no case more than 18 months, beginning with the month in which such plant resumes operation after such refueling. The refueling cycle shall be the applicable period of time between planned refueling outages for such plant. As of January 1, 2014, such amortized costs are a component of base rates, recoverable in base rates only ratably over the refueling cycle rather than when such outages occur, and are the only nuclear refueling costs recoverable in base rates. This provision shall apply to any nuclear-powered generating plant refueling outage commencing after December 31, 2013, and the Commission shall treat the deferred and amortized costs of such regulatory asset as part of the utility's costs for the purpose of proceedings conducted (a) with respect to ~~triennial~~ filings under subdivision 3 made on and after July 1, 2014, and (b) pursuant to § 56-245 or the Commission's rules governing utility rate increase applications as provided in subsection B. This provision shall not be deemed to change or reset base rates.

The Commission's final order regarding any petition filed pursuant to subdivision 4, 5, or 6 shall be entered not more than three months, eight months, and nine months, respectively, after the date of filing of such petition. If such petition is approved, the order shall direct that the applicable rate adjustment clause be applied to customers' bills not more than 60 days after the date of the order, or upon the expiration or termination of capped rates, whichever is later. *At any time, the Commission may, in its discretion, for a Phase II Utility, upon petition by a such a utility or upon its own initiated proceeding, direct the consolidation of any one or more subsets of rate adjustment clauses previously implemented pursuant to subdivision 5 or 6 in the interest of judicial economy, customer transparency, or other factors the Commission determines to be appropriate. Any subset of rate adjustment clauses so consolidated shall continue to be considered by the Commission without regard to the other costs, revenues, investments, or earnings of the utility and remain as a cost recovery mechanism independent from the utility's rates for generation and distribution services pursuant to this subdivision and subdivisions 5 and 6, but will be combined as a single rate adjustment clause for cost recovery and review purposes. Any rate adjustment clause or subset of rate adjustment clauses so consolidated shall be named in a manner, as determined by the Commission, that reasonably informs customers as to the nature of the costs recovered by the consolidated rate adjustment clause.*

8. In any ~~triennial~~ review proceeding, for the purposes of reviewing earnings on the utility's rates for generation and distribution services, the following utility generation and distribution costs not proposed for recovery under any other subdivision of this subsection, as recorded per books by the utility for financial reporting purposes and accrued against income, shall be attributed to the test periods under review and deemed fully recovered in the period recorded: costs associated with asset impairments related to early retirement determinations made by the utility for utility generation facilities fueled by coal, natural gas, or oil or for automated meter reading electric distribution service meters; costs associated with projects necessary to comply with state or federal environmental laws, regulations, or judicial or administrative orders relating to coal combustion by-product management that the utility does not petition to recover through a rate adjustment clause pursuant to subdivision 5 e; costs associated with severe weather events; and costs associated with natural disasters. Such costs shall be deemed to have been recovered from customers through rates for generation and distribution services in effect during the test periods under review unless such costs, individually or in the aggregate, together with the utility's other costs, revenues, and investments to be recovered through rates for generation and distribution services, result in the utility's earned return on its generation and distribution services for the combined test periods under review to fall more than 50 basis points below the fair combined rate of return authorized under subdivision 2 for such periods or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, to fall more than 70 basis points below the fair combined rate of return authorized under subdivision 2 for such periods. In such cases, the Commission shall, in such ~~triennial~~ review proceeding, authorize deferred recovery of such costs and allow the utility to amortize and recover such deferred costs over future periods as determined by the Commission. The aggregate amount of such deferred costs shall not exceed an amount that would, together with the utility's other costs, revenues, and investments to be recovered through rates for generation and distribution services, cause the utility's earned return on its generation and distribution services to exceed the fair rate of return authorized under subdivision 2, less 50 basis points, for the combined test periods under review or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, to exceed

the fair rate of return authorized under subdivision 2 less 70 basis points. *Notwithstanding the prior sentence, the aggregate amount of actual and reasonable costs associated with severe weather events eligible for such deferral shall not exceed an amount that would, together with the utility's other costs, revenues, and investments to be recovered through rates for generation and distribution services, cause the utility's earned return on its generation and distribution services to exceed the fair rate of return authorized for the combined test periods under review. For the purposes of determining any amount of costs that are associated with severe weather events, the Commission shall consider nationally recognized standards such as those published by the Institute of Electrical and Electronics Engineers (IEEE).* Nothing in this section shall limit the Commission's authority, pursuant to the provisions of Chapter 10 (§ 56-232 et seq.), including specifically § 56-235.2, following the review of combined test period earnings of the utility in a ~~triennial~~ review, for normalization of nonrecurring test period costs and annualized adjustments for future costs, in determining any appropriate increase or decrease in the utility's rates for generation and distribution services pursuant to subdivision 8 a or 8 c.

If the Commission determines as a result of ~~such~~ *any* triennial review *initiated prior to July 1, 2023* that:

a. Revenue reductions related to energy efficiency measures or programs approved and deployed since the utility's previous triennial review have caused the utility, as verified by the Commission, during the test period or periods under review, considered as a whole, to earn more than 50 basis points below a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points below a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall order increases to the utility's rates for generation and distribution services necessary to recover such revenue reductions. If the Commission finds, for reasons other than revenue reductions related to energy efficiency measures, that the utility has, during the test period or periods under review, considered as a whole, earned more than 50 basis points below a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points below a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn not less than such fair combined rate of return, using the most recently ended 12-month test period as the basis for determining the amount of the rate increase necessary. However, in the first triennial review proceeding conducted after January 1, 2021, for a Phase II Utility, the Commission may not order a rate increase, and in all triennial reviews of a Phase I or Phase II utility, the Commission may not order such rate increase unless it finds that the resulting rates are necessary to provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than a fair combined rate of return on both its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, using the most recently ended 12-month test period as the basis for determining the permissibility of any rate increase under the standards of this sentence, and the amount thereof; and provided that, solely in connection with making its determination concerning the necessity for such a rate increase or the amount thereof, the Commission shall, in any triennial review proceeding conducted prior to July 1, 2028, exclude from this most recently ended 12-month test period any remaining investment levels associated with a prior customer credit reinvestment offset pursuant to subdivision d.

b. The utility has, during the test period or test periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall, subject to the provisions of subdivisions 8 d and 9, direct that 60 percent of the amount of such earnings that were more than 50 basis points, or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, that 70 percent of the amount of such earnings that were more than 70 basis points, above such fair combined rate of return for the test period or periods under review, considered as a whole, shall be credited to customers' bills. Any such credits shall be amortized over a period of six to 12 months, as determined at the discretion of the Commission, following the effective date of the Commission's order, and shall be allocated among customer classes such that the relationship between the specific customer

class rates of return to the overall target rate of return will have the same relationship as the last approved allocation of revenues used to design base rates; or

c. ~~In any triennial review proceeding conducted after January 1, 2020, for a Phase I Utility or after January 1, 2021, for a Phase II Utility in which the~~ *The* utility has, during the test period or test periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matter determined with respect to facilities described in subdivision 6, and the combined aggregate level of capital investment that the Commission has approved other than those capital investments that the Commission has approved for recovery pursuant to a rate adjustment clause pursuant to subdivision 6 made by the utility during the test periods under review in that triennial review proceeding in new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, and in electric distribution grid transformation projects, as determined pursuant to subdivision 8 d, does not equal or exceed 100 percent of the earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services for the combined test periods under review in that triennial review proceeding, the Commission shall, subject to the provisions of subdivision ~~9~~ *10* and in addition to the actions authorized in subdivision b, also order reductions to the utility's rates it finds appropriate. However, in the first triennial review proceeding conducted after January 1, 2021, for a Phase II Utility, any reduction to the utility's rates ordered by the Commission pursuant to this subdivision shall not exceed $50 million in annual revenues, with any reduction allocated to the utility's rates for generation services, and in each triennial review of a Phase I or Phase II Utility, the Commission may not order such rate reduction unless it finds that the resulting rates will provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, using the most recently ended 12-month test period as the basis for determining the permissibility of any rate reduction under the standards of this sentence, and the amount thereof; and

d. (Expires July 1, 2028) In any ~~triennial~~ review proceeding conducted after December 31, 2017, upon the request of the utility, the Commission shall determine, prior to directing that 70 percent of earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services for the test period or periods under review be credited to customer bills pursuant to subdivision 8 b, the aggregate level of prior capital investment that the Commission has approved other than those capital investments that the Commission has approved for recovery pursuant to a rate adjustment clause pursuant to subdivision 6 made by the utility during the test period or periods under review in both (i) new utility-owned generation facilities utilizing energy derived from sunlight, or from onshore or offshore wind, and (ii) electric distribution grid transformation projects, as determined by the utility's plant in service and construction work in progress balances related to such investments as recorded per books by the utility for financial reporting purposes as of the end of the most recent test period under review. Any such combined capital investment amounts shall offset any customer bill credit amounts, on a dollar for dollar basis, up to the aggregate level of invested or committed capital under clauses (i) and (ii). The aggregate level of qualifying invested or committed capital under clauses (i) and (ii) is referred to in this subdivision as the customer credit reinvestment offset, which offsets the customer bill credit amount that the utility has invested or will invest in new solar or wind generation facilities or electric distribution grid transformation projects for the benefit of customers, in amounts up to 100 percent of earnings that are more than 70 basis points above the utility's fair rate of return on its generation and distribution services, and thereby reduce or eliminate otherwise incremental rate adjustment clause charges and increases to customer bills, which is deemed to be in the public interest. If 100 percent of the amount of earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services, as determined in subdivision 2, exceeds the aggregate level of invested capital in new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, and electric distribution grid transformation projects, as provided in clauses (i) and (ii), during the test period or periods under review, then 70 percent of the amount of such excess shall be credited to customer bills as provided in subdivision 8 b in connection with the ~~triennial~~ review proceeding. The portion of any costs associated with new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that is the subject of any customer credit reinvestment offset pursuant to this subdivision shall not thereafter be recovered through the utility's rates for generation and distribution services over the service life of such facilities and shall not thereafter be included in the utility's costs, revenues, and investments in future ~~triennial~~ review proceedings conducted

pursuant to subdivision 2 and shall not be the subject of a rate adjustment clause petition pursuant to subdivision 6. The portion of any costs associated with new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that is not the subject of any customer credit reinvestment offset pursuant to this subdivision may be recovered through the utility's rates for generation and distribution services over the service life of such facilities and shall be included in the utility's costs, revenues, and investments in future ~~triennial~~ review proceedings conducted pursuant to subdivision 2 until such costs are fully recovered, and if such costs are recovered through the utility's rates for generation and distribution services, they shall not be the subject of a rate adjustment clause petition pursuant to subdivision 6. Only the portion of such costs of new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that has not been included in any customer credit reinvestment offset pursuant to this subdivision, and not otherwise recovered through the utility's rates for generation and distribution services, may be the subject of a rate adjustment clause petition by the utility pursuant to subdivision 6.

The Commission's final order regarding such ~~triennial~~ review shall be entered not more than eight months after the date of filing, and any revisions in rates or credits so ordered shall take effect not more than 60 days after the date of the order. The fair combined rate of return on common equity determined pursuant to subdivision 2 in such ~~triennial~~ review shall apply, for purposes of reviewing the utility's earnings on its rates for generation and distribution services, to the entire *two or* three, *as applicable,* successive 12-month test periods ending December 31 immediately preceding the year of the utility's subsequent ~~triennial~~ review filing under subdivision 3 and shall apply to applicable rate adjustment clauses under subdivisions 5 and 6 prospectively from the date the Commission's final order in the ~~triennial~~ review proceeding, utilizing rate adjustment clause true-up protocols as the Commission in its discretion may determine.

9. *a. In any biennial review for a Phase II Utility filed on or prior to December 31, 2023, if the Commission determines that the utility has during the test period or test periods under review, considered as a whole, earned more than 70 basis points above a fair combined rate of return on its generation and distribution services previously authorized by the Commission, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, which have not been combined with the utility's costs, revenues, and investments for generation and distribution services, the Commission shall direct that 85 percent of the amount of such earnings that were more than 70 basis points above such fair combined rate of return for the test period or periods under review, considered as a whole, be credited to customers' bills. Any such credits shall be amortized over a period of six to 12 months, as determined at the discretion of the Commission, following the effective date of the Commission's order, and shall be allocated among customer classes such that the relationship between the specific customer class rates of return to the overall target rate of return will have the same relationship as the last approved allocation of revenues used to design base rates.*

b. In any biennial review for a Phase II Utility filed on or after January 1, 2024, if the Commission determines that the utility has during the test period or test periods under review, considered as a whole, earned above its fair combined rate of return on its generation and distribution services previously authorized by the Commission, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, which have not been combined with the utility's costs, revenues, and investments for generation and distribution services, the Commission shall direct that 85 percent of the amount of such earnings above such fair combined rate of return for the test period or periods under review, considered as a whole, be credited to customers' bills. Further, if the Commission determines that during the test period or test periods under review, considered as a whole, a Phase II Utility earned more than 150 basis points above a fair combined rate of return on its generation and distribution services previously authorized by the Commission, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, which have not been combined with the utility's costs, revenues, and investments for generation and distribution services, the Commission shall direct that all such earnings that were more than 150 basis points above such fair combined rate of return for the test period or periods under review, considered as a whole, be credited to customers' bills. Any such credits shall be amortized over a period of six to 12 months, as determined at the discretion of the Commission, following the effective date of the Commission's order, and shall be allocated among customer classes such that the relationship between the specific customer class rates of return to the overall target rate of return will have the same relationship as the last approved allocation of revenues used to design base rates.

10. If, as a result of a triennial review required under this subsection and conducted with respect to any test period or periods under review ending later than December 31, 2010 (or, if the Commission has

elected to stagger its biennial reviews of utilities as provided in subdivision 1, under review ending later than December 31, 2010, for a Phase I Utility, or December 31, 2011, for a Phase II Utility), the Commission finds, with respect to such test period or periods considered as a whole, that (i) any utility has, during the test period or periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, and (ii) the total aggregate regulated rates of such utility at the end of the most recently ended 12-month test period exceeded the annual increases in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, compounded annually, when compared to the total aggregate regulated rates of such utility as determined pursuant to the review conducted for the base period, the Commission shall, unless it finds that such action is not in the public interest or that the provisions of subdivisions 8 b and c are more consistent with the public interest, direct that any or all earnings for such test period or periods under review, considered as a whole that were more than 50 basis points, or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points, above such fair combined rate of return shall be credited to customers' bills, in lieu of the provisions of subdivisions 8 b and c, provided that no credits shall be provided pursuant to this subdivision in connection with any triennial review unless such bill credits would be payable pursuant to the provisions of subdivision 8 d, and any credits under this subdivision shall be calculated net of any customer credit reinvestment offset amounts under subdivision 8 d. Any such credits shall be amortized and allocated among customer classes in the manner provided by subdivision 8 b. For purposes of this subdivision:

"Base period" means (i) the test period ending December 31, 2010 (or, if the Commission has elected to stagger its biennial reviews of utilities as provided in subdivision 1, the test period ending December 31, 2010, for a Phase I Utility, or December 31, 2011, for a Phase II Utility), or (ii) the most recent test period with respect to which credits have been applied to customers' bills under the provisions of this subdivision, whichever is later.

"Total aggregate regulated rates" shall include: (i) fuel tariffs approved pursuant to § 56-249.6, except for any increases in fuel tariffs deferred by the Commission for recovery in periods after December 31, 2010, pursuant to the provisions of clause (ii) of subsection C of § 56-249.6; (ii) rate adjustment clauses implemented pursuant to subdivision 4 or 5; (iii) revisions to the utility's rates pursuant to subdivision 8 a; (iv) revisions to the utility's rates pursuant to the Commission's rules governing utility rate increase applications, as permitted by subsection B, occurring after July 1, 2009; and (v) base rates in effect as of July 1, 2009.

~~10.~~ *11.* For purposes of this section, the Commission shall regulate the rates, terms and conditions of any utility subject to this section on a stand-alone basis utilizing the actual end-of-test period capital structure and cost of capital of such utility, excluding any debt associated with securitized bonds that are the obligation of non-Virginia jurisdictional customers, unless the Commission finds that the debt to equity ratio of such capital structure is unreasonable for such utility, in which case the Commission may utilize a debt to equity ratio that it finds to be reasonable for such utility in determining any rate adjustment pursuant to subdivisions 8 a and c, and without regard to the cost of capital, capital structure, revenues, expenses or investments of any other entity with which such utility may be affiliated. In particular, and without limitation, the Commission shall determine the federal and state income tax costs for any such utility that is part of a publicly traded, consolidated group as follows: (i) such utility's apportioned state income tax costs shall be calculated according to the applicable statutory rate, as if the utility had not filed a consolidated return with its affiliates, and (ii) such utility's federal income tax costs shall be calculated according to the applicable federal income tax rate and shall exclude any consolidated tax liability or benefit adjustments originating from any taxable income or loss of its affiliates.

B. Nothing in this section shall preclude an investor-owned incumbent electric utility from applying for an increase in rates pursuant to § 56-245 or the Commission's rules governing utility rate increase applications; however, in any such filing, a fair rate of return on common equity shall be determined pursuant to subdivision A 2. Nothing in this section shall preclude such utility's recovery of fuel and purchased power costs as provided in § 56-249.6.

C. Except as otherwise provided in this section, the Commission shall exercise authority over the rates, terms and conditions of investor-owned incumbent electric utilities for the provision of generation, transmission and distribution services to retail customers in the Commonwealth pursuant to the provisions of Chapter 10 (§ 56-232 et seq.), including specifically § 56-235.2.

D. The Commission may determine, during any proceeding authorized or required by this section, the reasonableness or prudence of any cost incurred or projected to be incurred, by a utility in connection with the subject of the proceeding. A determination of the Commission regarding the reasonableness or prudence of any such cost shall be consistent with the Commission's authority to determine the reasonableness or prudence of costs in proceedings pursuant to the provisions of Chapter 10 (§ 56-232 et seq.). In determining the reasonableness or prudence of a utility providing energy and capacity to its customers from renewable energy resources, the Commission shall consider the extent to which such renewable energy resources, whether utility-owned or by contract, further the objectives of the Commonwealth Clean Energy Policy set forth in § 45.2-1706.1, and shall also consider whether the costs of such resources is likely to result in unreasonable increases in rates paid by customers.

E. Notwithstanding any other provision of law, the Commission shall determine the amortization period for recovery of any appropriate costs due to the early retirement of any electric generation facilities owned or operated by any Phase I Utility or Phase II Utility. In making such determination, the Commission shall (i) perform an independent analysis of the remaining undepreciated capital costs; (ii) establish a recovery period that best serves ratepayers; and (iii) allow for the recovery of any carrying costs that the Commission deems appropriate.

F. *The Commission shall include in its report required by subsection B of § 56-596 any information concerning the reliability impacts of generation unit additions and retirement determinations by a Phase I or Phase II Utility, along with the potential impact on the purchase of power from generation assets outside the Virginia jurisdiction used to serve the utility's native load, utilizing information from the respective utility's integrated resource plan or information from the respective utility's plan filed pursuant to subsection D of § 56-585.5.*

G. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this section.

§ 56-585.1:4. Development of solar and wind generation and energy storage capacity in the Commonwealth.

A. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic shoreline, each having a rated capacity of at least one megawatt and having in the aggregate a rated capacity that does not exceed 5,000 megawatts, or (ii) the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities described in clause (i) owned by persons other than a public utility is in the public interest, and the Commission shall so find if required to make a finding regarding whether such construction or purchase is in the public interest.

B. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic shoreline, each having a rated capacity of less than one megawatt, including rooftop solar installations with a capacity of not less than 50 kilowatts, and having in the aggregate a rated capacity that does not exceed 500 megawatts, or (ii) the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities described in clause (i) owned by persons other than a public utility is in the public interest, and the Commission shall so find if required to make a finding regarding whether such construction or purchase is in the public interest.

C. The aggregate cap of 5,000 megawatts of rated capacity described in clause (i) of subsection A, the aggregate cap of 500 megawatts of rated capacity described in clause (i) of subsection B, and the aggregate cap of 200 megawatts of rated capacity described in subsection I are separate and independent from each other. The capacity of facilities in subsection B shall not be counted in determining the capacity of facilities in subsection A or I; the capacity of facilities in subsection A shall not be counted in determining the capacity of facilities in subsection B or I; and the capacity of facilities in subsection I shall not be counted in determining the capacity of facilities in subsection A or B.

D. Twenty-five percent of the solar generation capacity placed in service on or after July 1, 2018, located in the Commonwealth, and found to be in the public interest pursuant to subsection A or B shall be from the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities owned by persons other than a public utility. The remainder shall be construction or purchase by a public utility of one or more solar generation facilities located in the Commonwealth. All of the solar generation capacity located in the Commonwealth and found to be in the public interest pursuant to subsection A or B shall be subject to competitive procurement, provided that a public utility may select solar generation capacity without regard to whether such selection satisfies price criteria if the selection of the solar generating capacity materially advances non-price criteria, including favoring geographic distribution of generating capacity, areas of higher employment, or regional economic development, if such non-price solar generating capacity selected does not exceed 25 percent of the utility's solar generating capacity.

E. Construction, purchasing, or leasing activities for a test or demonstration project for a new

utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore wind with an aggregate capacity of not more than 16 megawatts are in the public interest.

F. Prior to January 1, 2035, (i) the construction by a public utility of one or more energy storage facilities located in the Commonwealth, having in the aggregate a rated capacity that does not exceed 2,700 megawatts, or (ii) the purchase by a public utility of energy storage facilities described in clause (i) owned by persons other than a public utility or the capacity from such facilities is in the public interest, and the Commission shall so find if required to make a finding regarding whether such construction or purchase is in the public interest.

G. At least 35 percent of the energy storage capacity placed in service on or after July 1, 2020, located in the Commonwealth and found to be in the public interest pursuant to subsection F shall be from the purchase by a public utility of energy storage facilities owned by persons other than a public utility or the capacity from such facilities. All of the energy storage facilities located in the Commonwealth and found to be in the public interest pursuant to subsection F shall be subject to competitive procurement, provided that a public utility may select energy storage facilities without regard to whether such selection satisfies price criteria if the selection of the energy storage facilities materially advances non-price criteria, including favoring geographic distribution of generating facilities, areas of higher employment, or regional economic development, if such energy storage facilities selected for the advancement of non-price criteria do not exceed 25 percent of the utility's energy storage capacity.

H. A utility may elect to petition the Commission, outside of a triennial *or biennial* review proceeding conducted pursuant to § 56-585.1, at any time for a prudency determination with respect to the construction or purchase by the utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic Shoreline or the purchase by the utility of energy, capacity, and environmental attributes from solar or wind facilities owned by persons other than the utility. The Commission's final order regarding any such petition shall be entered by the Commission not more than three months after the date of the filing of such petition.

I. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar or wind generation facilities located on a previously developed project site in the Commonwealth having in the aggregate a rated capacity that does not exceed 200 megawatts or (ii) the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities described in clause (i) owned by persons other than a public utility, is in the public interest.

§ 56-599. Integrated resource plan required.

A. Each electric utility shall file an updated integrated resource plan by July 1, 2015. Thereafter, each electric utility shall file an updated integrated resource plan by May 1, in each year immediately preceding the year the utility is subject to a triennial *or biennial* review filing. A copy of each integrated resource plan shall be provided to the Chairman of the House Committee on Labor and Commerce, the Chairman of the Senate Committee on Commerce and Labor, and to the Chairman of the Commission on Electric Utility Regulation. All updated integrated resource plans shall comply with the provisions of any relevant order of the Commission establishing guidelines for the format and contents of updated and revised integrated resource plans. Each integrated resource plan shall consider options for maintaining and enhancing rate stability, energy independence, economic development including retention and expansion of energy-intensive industries, and service reliability.

B. In preparing an integrated resource plan, each electric utility shall systematically evaluate and may propose:

1. Entering into short-term and long-term electric power purchase contracts;

2. Owning and operating electric power generation facilities;

3. Building new generation facilities;

4. Relying on purchases from the short term or spot markets;

5. Making investments in demand-side resources, including energy efficiency and demand-side management services;

6. Taking such other actions, as the Commission may approve, to diversify its generation supply portfolio and ensure that the electric utility is able to implement an approved plan;

7. The methods by which the electric utility proposes to acquire the supply and demand resources identified in its proposed integrated resource plan;

8. The effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities;

9. The most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations;

10. Long-term electric distribution grid planning and proposed electric distribution grid

transformation projects;

11. Developing a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity; and

12. Developing a long-term plan to integrate new energy storage facilities into existing generation and distribution assets to assist with grid transformation.

C. As part of preparing any integrated resource plan pursuant to this section, each utility shall conduct a facility retirement study for owned facilities located in the Commonwealth that emit carbon dioxide as a byproduct of combusting fuel and shall include the study results in its integrated resource plan. Upon filing the integrated resource plan with the Commission, the utility shall contemporaneously disclose the study results to each planning district commission, county board of supervisors, and city and town council where such electric generation unit is located, the Department of Energy, the Department of Housing and Community Development, the Virginia Employment Commission, and the Virginia Council on Environmental Justice. The disclosure shall include (i) the driving factors of the decision to retire and (ii) the anticipated retirement year of any electric generation unit included in the plan. Any electric generating facility with an anticipated retirement date that meets the criteria of § 45.2-1701.1 shall comply with the public disclosure requirements therein.

D. The Commission shall analyze and review an integrated resource plan and, after giving notice and opportunity to be heard, the Commission shall make a determination within nine months after the date of filing as to whether such an integrated resource plan is reasonable and is in the public interest.

2. That in any biennial review initiated by a Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, as amended by this act, on or prior to December 31, 2023, the State Corporation Commission shall set the combined fair rate of return at 9.70 percent, which is based on the simple average of the authorized returns for vertically integrated electric utilities by the applicable regulatory commissions in the peer group jurisdictions of Florida, Georgia, Texas, Tennessee, West Virginia, Kentucky, and North Carolina. Such combined fair rate of return on common equity shall be applicable separately to the generation and distribution services of such utility, and for the two such services combined, and for any rate adjustment clauses approved under subdivision A 5 or 6 of § 56-585.1 of the Code of Virginia, as amended by this act. For any review initiated by such a utility after December 31, 2023, the Commission may use any methodology to determine such return it finds consistent with the public interest pursuant to its authority under subdivision A 2 a of § 56-585.1 of the Code of Virginia, as amended by this act.

3. That a Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, as amended by this act, shall, through December 31, 2024, undertake reasonable efforts to maintain, subject to audit by the State Corporation Commission, its common equity capitalization to total capitalization ratio at a level equal to 52.10 percent.

4. That a Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, as amended by this act, in connection with any financing order petition filed with the State Corporation Commission (the Commission) prior to December 31, 2023, pursuant to § 56-249.6:1 of the Code of Virginia, as created by this act, shall permit any retail customer that is receiving electric supply service from the utility and whose demand exceeded five megawatts during the calendar year prior to such petition to opt out of financing its pro rata obligation for deferred fuel cost charges through deferred fuel cost bonds. The utility shall notify such eligible customers of their eligibility to opt out of the deferred fuel cost financing through its annual petition with the Commission pursuant to § 56-249.6 of the Code of Virginia, and any election to opt out of the deferred fuel cost financing by an eligible customer shall be provided in writing to the utility within 30 days of the filing of such petition. Upon such election, the eligible customer shall fully satisfy its pro rata obligation for the deferred fuel cost charges subject to financing, as determined based on its electric usage over the period that such charges were incurred, over the 12-month period prescribed by subsection C of § 56-249.6 of the Code of Virginia that is associated with such annual petition. In the event of such election, any deferred fuel cost charges approved for recovery through deferred fuel cost bonds shall not include the obligations of eligible customers opting out of the deferred fuel cost financing.

5. That for purposes of considering future performance-based adjustments to the combined rate of return in accordance with subdivision A 2 c of § 56-585.1 of the Code of Virginia, as amended by this act, the State Corporation Commission (the Commission), before December 31, 2023, shall direct the initiation of a proceeding to review and determine the appropriate protocols and standards applicable to implementing any such performance-based adjustments. The protocols and standards established as a result of such a proceeding shall apply to biennial review filings occurring on or after January 1, 2025. However, if the Commission determines that the public

interest would be better served by implementing such protocols and standards for biennial review filings occurring on or after January 1, 2027, then such performance standards and protocols shall be applicable to all biennial rate review filings made on or after January 1, 2027. Until such standards and protocols are applicable, the Commission shall have the authority, consistent with its precedent for incumbent electric utilities prior to the enactment of Chapters 888 and 933 of the Acts of Assembly of 2007, to increase or decrease the utility's combined rate of return based on the Commission's consideration of the utility's performance.+

Attachment 82

ENERGY + ENVIRONMENT
GENERAL ASSEMBLY 2023

General Assembly deal sets Dominion profits for two years while overhauling regulatory system

Gov. Glenn Youngkin calls legislation ‘a big step forward on behalf of all Virginians’

By: Charlie Paullin - February 25, 2023 6:27 pm

The Virginia General Assembly. (Sarah Vogelsong / Virginia Mercury)

The decision came down to the wire, but on Saturday afternoon Gov. Glenn Youngkin’s office and the General Assembly reached a deal on sweeping legislation to adjust Dominion Energy’s profit margin and reform the state’s system of electric utility regulation.

The bills, carried by Senate Majority Leader Dick Saslaw, D-Fairfax, and House Majority Leader Terry Kilgore, R-Scott, passed the Senate on a unanimous vote, with only one vote in the House — from Del. Dave LaRock, R-Clarke — opposing it.

The final language of the bill, which has been under negotiation all session, will set Dominion’s profit margin at 9.7% for two years. After that, the State Corporation Commission, which in Virginia oversees electric utilities, will have the authority to set the profit margin at its discretion.

Dominion’s current profit margin — the amount it is allowed to earn in addition to the costs of providing service to regulated ratepayers in Virginia — is 9.35%.

Kilgore said the reason for the two-year bump was to ensure Dominion would be in a better position to go to the bond market to seek capital to build new generation as well as provide stability to the company before the SCC takes “unfettered” control.

Among other provisions, the bill resets rate reviews from every three years to two starting this summer and will roll into base rates $350 million worth of rate adjustment clauses, or extra charges for specific projects added onto customers’ bills. The SCC has estimated the latter change will lower the average monthly residential bill by $6 to $7.

Dominion will gain the ability to issue about $1.6 billion in bonds to pay for fuel upfront and recover those costs over a 10-year period. The move, known as fuel securitization, is designed to cushion customers from the impacts of spiking fuel costs that could lead to a $17 monthly bill increase for residential customers.

The final version no longer includes language that alters the plant closure schedule set by the Virginia Clean Economy Act, a 2020 law requiring the utilities to decarbonize by midcentury. Instead, it asks the SCC to report on concerns about the reliability of new generation units and retirement determinations.

The legislation also changes the percentage of excess earnings Dominion is allowed to keep. Currently, if the SCC determines that Dominion overearned, the utility is still allowed to keep 30% of those earnings. The bill decreases that number to 15% for the 2023 rate case and removes for future rate cases a complex legislative framework that prescribes by statute a range of profits within which the company is allowed to earn.

Minority Leader Tommy Norment, R-Williamsburg, said he couldn't recall a piece of legislation that was "more negotiated" and involved "more participants."

Both parties praised the final version. Kilgore called it a "well-rounded, good deal for Virginians." Del. Rip Sullivan, D-Arlington, said, "I'm glad that we took the time we did."

Youngkin, who has railed against high energy costs and intervened in the negotiations, said the measure was "a big step forward on behalf of all Virginians."

"I applaud the legislators who took the lead on writing and negotiating this landmark bill, which will save customers money on their monthly bills, restore the independent oversight of the State Corporation Commission, and support the long-term stability of Virginia's largest electric utility," he said.

Dominion too said it supported the bill.

"This legislation is a win for consumers and regulatory oversight," said Dominion spokesperson Aaron Ruby in a statement. "It will lower electricity bills for our customers, reduce the impact of rising fuel costs and strengthen SCC oversight."

The reaction varied among environmental and ratepayer groups.

"For far too long, Dominion Energy has wielded its political influence and contributions to write the rules of its own regulation. This year's legislative session has shown definitively that this era of self-regulation has come to an end," said Brennan Gilmore, executive director of Clean Virginia, a group created by Charlottesville millionaire Michael Bills explicitly to oppose Dominion's influence in the General Assembly.

Albert Pollard, a lobbyist for the Virginia Poverty Law Center, took a more lukewarm approach, criticizing a provision that sets Dominion's debt-to-equity ratio but saying he thought it was worth accepting with the restoration of SCC oversight after two years.

The Sierra Club of Virginia switched its position from opposing the bill to taking a neutral stance after the removal of the provision changing the plant closure schedule set by the Virginia Clean Economy Act. Although some of Dominion's coal and oil plants are already scheduled to retire within the next few years, some environmental groups were concerned that altering the timeline would slow efforts to transition to renewable energy.

Despite the bill's passage, the House and Senate have still not resolved a disagreement over appointments to fill two vacancies on the SCC. With only one remaining member on the body, keeping the seats vacant could prevent the SCC from having a necessary quorum in the future.

"None of this works unless we can reach that compromise," said Sen. Scott Surovell, D-Fairfax.

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Attachment 83

U.S. Energy Information Administration

Skip to sub-navigation
< Electricity Data

Electricity Data Browser

Explore the new Beta version with expanded plant level data for water cooling and emissions.

Change data set

Average retail price of electricity

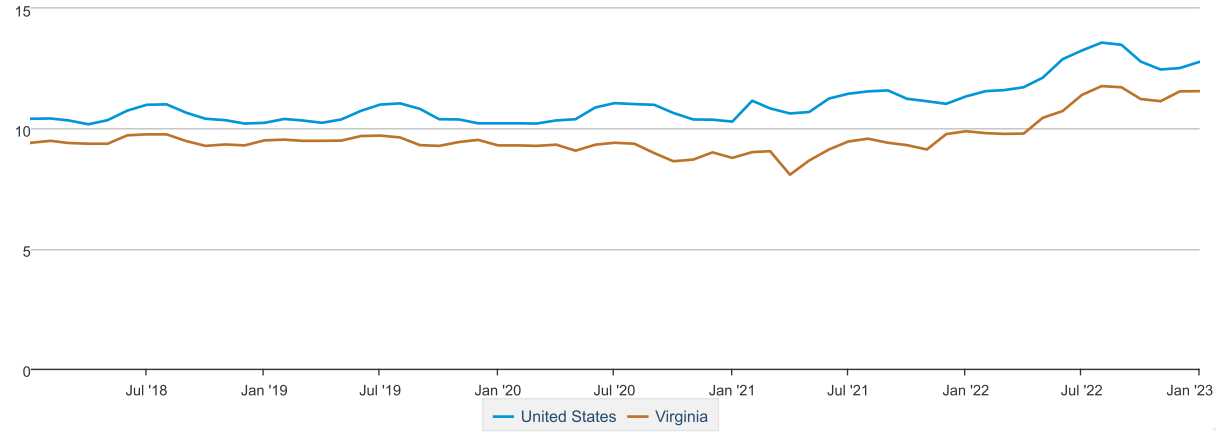
OR

View a pre-generated report

Choose a report

Average retail price of electricity, all sectors, monthly

cents per kilowatthour



Data source: U.S. Energy Information Administration

Change data set

Average retail price of electricity

OR

View a pre-generated report

Choose a report

DOWNLOAD

HELP

FILTER/ORDER | ANALYSIS | Time-series | Column | Map | Pin | API

Jan 2018 — Jan 2023

Annual | Quarterly | Monthly

	Oct 2022	Nov 2022	Dec 2022	Jan 2023
Average retail price of electricity (cents per kilowatthour)				
All sectors				
United States	12.79	12.46	12.52	12.78
South Atlantic				
Virginia	11.23	11.14	11.55	11.56

NM = Not meaningful due to large relative standard error. Show relative standard errors expressed as percent in parenthesis: ☐

Terms and definitions

Attachment 84

2022-0259

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

PETITION OF

APPALACHIAN POWER COMPANY **CASE NO. PUR-2022-00001**

For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia

2022 OCT 18 P 1:47

REPORT OF D. MATHIAS ROUSSY, JR., HEARING EXAMINER

October 18, 2022

This State Corporation Commission ("Commission") case involves a proposal by Appalachian Power Company ("APCo" or "Company") to recover certain costs through a rate adjustment clause available for the costs of complying with environmental laws and regulations.

Three issues are contested. First, APCo seeks Commission approval of Effluent Limitations Guidelines ("ELG") compliance costs at Amos and Mountaineer, which the *2021 E-RAC Order*[1] denied without prejudice after APCo failed to carry its burden of proof. The West Virginia Public Service Commission ("WVPSC") has decided that West Virginia will pay up to 100% of the ELG costs, meaning these two coal-fired power plants will continue to operate beyond the December 31, 2028 compliance deadline, regardless of the Commission's decision in the instant case. Amos and Mountaineer are, by far, APCo's largest capacity resources. Additionally, when these plants are dispatched economically, they provide APCo's customers access to their generated electricity or, when it is less expensive, market electricity. Based on the economic analyses in this case, I find APCo established that it would likely be beneficial for Virginia to help pay for compliance at Mountaineer and, to a lesser extent, Amos, subject to ratemaking conditions to protect Virginia from a risk of uneconomic regulatory dispatch identified in the record. However, if the Commission assigns more weight to this risk or less weight to market risk, the record could support a decision for Virginia not to pay for ELG compliance at Amos or, to a lesser extent, Mountaineer.

Second, I recommend that the Commission deny rate adjustment recovery of one project that the record indicates is not necessary for environmental compliance. Any such denial should be without prejudice as it appears this project would be eligible for recovery through base rates.

Third, I recommend that the Commission deny without prejudice a small portion of emission allowance costs proposed by APCo.

Based on these recommendations, I recommend a $32.9 million revenue requirement for service to be rendered beginning December 1, 2022, which is $0.7 million lower than proposed.

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[1] *Petition of Appalachian Power Company, For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2020-00258, 2021 S.C.C. Ann. Rep. 330, Order Granting Rate Adjustment Clause (Aug. 23, 2021) ("*2021 E-RAC Order*" or "2021 E-RAC Case," as applicable).

2022-00082

PROCEDURAL HISTORY

On March 18, 2022, APCo filed a Petition with the Commission seeking approval to recover costs through an existing rate adjustment clause, the "E-RAC", pursuant to § 56-585.1 A 5 e of the Code of Virginia ("Code").[2] According to APCo, the costs the Petition seeks to recover relate to capital investments and operations and maintenance ("O&M") compliance expenses that are necessary to comply with state and federal environmental regulations. APCo filed public and confidential versions of its Petition, accompanied by a Motion for Protective Ruling.

On April 21, 2022, the Commission issued an Order for Notice and Hearing that, among other things, docketed the Petition; granted certain waivers requested by APCo, as set forth therein; directed the Commission's Staff ("Staff") to investigate the Petition and to file testimony containing the results of Staff's investigation; established a procedural schedule, including a telephonic hearing on September 20, 2022, to receive the testimony of public witnesses and a hearing on September 21, 2022, to receive the evidence of the parties and Staff; provided interested persons opportunities to participate in this proceeding; and appointed a Hearing Examiner to conduct all further proceedings on behalf of the Commission.

On May 10, 2022, a Hearing Examiner's Protective Ruling was issued.

On May 24, 2022, APCo filed its Motion for Additional Protective Treatment for Extraordinarily Sensitive Information ("Second Protective Motion"). In its Second Protective Motion, APCo sought heightened protective treatment of two attachments to the Company's responses to discovery requests. On June 1, 2022, the Hearing Examiner's Protective Ruling Providing Additional Protective Treatment for Extraordinarily Sensitive Information was issued.

On June 7, 2022, APCo filed proof of notice and service.[3]

Notices of participation in this proceeding were filed by: the Sierra Club;[4] West Virginia Coal Association, Inc. ("Coal Association");[5] Appalachian Voices;[6] and the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel").

On June 9, 2022, Sierra Club filed a Motion to Compel Discovery. On June 30, 2022, APCo filed its Response in Opposition to Sierra Club's Motion to Compel Discovery. On July 6, 2022, Sierra Club filed its Reply. A Hearing Examiner's Ruling issued on July 13, 2022, granted in part and denied in part Sierra Club's Motion to Compel Discovery.

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[2] On March 31, 2022, APCo filed Schedule 3 to the Petition. On May 17, 2022, APCo filed a page of Company witness Martin's testimony that was inadvertently omitted from the initial filing.
[3] Exhibit ("Ex.") 3.
[4] On April 22, 2022, Sierra Club filed a Motion for Admission *Pro Hac Vice* of Dorothy E. Jaffe, which was granted by a Hearing Examiner's Ruling issued on May 26, 2022.
[5] On June 7, 2022, the Coal Association filed Motions for Admission *Pro Hac Vice* of Jacob C. Altmeyer and H. Brann Altmeyer, which were granted by a Hearing Examiner's Ruling issued on June 14, 2022.
[6] On August 2, 2022, Appalachian Voices filed a Motion for Admission *Pro Hac Vice* of Rachel James, which was granted by a Hearing Examiner's Ruling issued on August 3, 2022.

One public comment was filed on May 31, 2022, by the Tazewell County Board of Supervisors ("Tazewell Board"). The Tazewell Board requested that the rate increase proposed in this case and in Case No. PUR-2022-00014 both be denied in light of the impact on Tazewell County residents. The comments stressed, among other things, the relatively low median household income in the County and the high poverty rate. The financial and social hardships in the County have been compounded by rampant inflation.

The public witness portion of the evidentiary hearing was cancelled because no one signed up to testify.

On September 21, 2022, the hearing was conducted, as scheduled, in the Commission's courtroom. Noelle J. Coates, Esquire, Daniel Summerlin, Esquire, and April M. Jones, Esquire, appeared on behalf of APCo. Evan Dimond Johns, Esquire, and Dorothy E. Jaffe, Esquire, appeared on behalf of Sierra Club. Neil S. Talegaonkar, Esquire, appeared on behalf of the Coal Association. William C. Cleveland, Esquire, and Rachel James, Esquire, appeared on behalf of Appalachian Voices. C. Meade Browder, Jr., Esquire, and R. Scott Herbert, Esquire, appeared on behalf of Consumer Counsel. Frederick D. Ochsenhirt, Esquire, appeared on behalf of Staff.

SUMMARY OF THE RECORD

APCo – Direct

In support of its Petition, APCo presented the direct testimonies of **Christian T. Beam**, President and Chief Operating Officer of APCo; **James F. Martin**, Director of Resource Planning Strategy for American Electric Power Service Corporation ("AEPSC"); **Brian D. Sherrick**, Vice President of Generation Shared Services for AEPSC;[7] **Robert A. Gallimore**, Hydroelectric Asset Manager for AEPSC; **Gary O. Spitznogle**, Vice President of Environmental Services at AEPSC; **Tyler H. Ross**, Director of Regulatory Accounting Services for AEPSC; and **William K. Castle**, Director, Regulatory Services - VA/TN for APCo.

As discussed further by the Company's witnesses, the Petition summarized the applicable state or federal environmental regulations as follows below.[8]

> *i. The CCR Rule*[9]
> In 2015, the United States Environmental Protection Agency ("EPA") published a final rule to regulate the disposal of coal combustion residuals [("CCR")], the CCR Rule, which includes fly ash, bottom ash, and gypsum that may be generated at coal-fired electric generating units. The CCR Rule applies to new and existing CCR landfills and CCR surface impoundments (ponds) at operating coal-based electric generating facilities. Recent revisions to the CCR Rule require that unlined CCR storage ponds must cease operations and initiate closure by

[7] Mr. Sherrick assumed this position in July 2022. Tr. at 62 (Sherrick).
[8] Ex. 4 (Petition) at 6-7.
[9] Ex. 9 (Spitznogle direct) at attached Sched. 1 (citing the CCR Rule as 40 C.F.R. 257.50(b)).

April 11, 2021. The EPA can extend the compliance date for [Amos and Mountaineer] to as late as October 15, 2023.

ii. The ELG Rule[10]
The Steam Electric Effluent Limitations Guidelines, the ELG Rule, establishes discharge limits on flue gas desulfurization wastewater, fly ash and bottom ash transport water, and flue gas mercury control wastewater. Recent revisions to the ELG Rule establish discharge limits that must be achieved as soon as possible between October 13, 2021 and December 31, 2025 based on the renewal of the existing wastewater discharge permit for the facility.

iii. Dissolved Oxygen Requirements[11]
The dissolved oxygen requirements at Claytor were issued by the Federal Energy Regulatory Commission ("FERC") and are designed to improve low dissolved oxygen conditions in accordance with Virginia Department of [Environmental] Quality ("DEQ") requirements.

iv. Cross-State Air Pollution Rule[12]
[APCo] installed the [dry sorbent injection system] at Amos to mitigate emissions of [sulfur trioxide ("SO_3")] that result from the operation of the Selective Catalytic Reduction ("SCR") and Flue Gas Desulfurization ("FGD") systems in tandem. [APCo] installed the SCR and FGD systems to comply with what is now the Cross-State Air Pollution Rule, as well as a consent decree with the EPA and others.

v. [Regional Greenhouse Gas Initiative ("RGGI")][13]
In 2020, the Virginia General Assembly amended the Clean Energy and Community Flood and Preparedness Act to direct the Virginia DEQ to adopt regulations to establish a cap-and-trade program for carbon dioxide [("CO_2")] emissions to comply with the RGGI Model Rule. Those regulations became effective in July 2020, and are applicable to Clinch River, which is the Company's only fossil-fuel fired generation facility in the Commonwealth.

vi. Other Applicable Environmental Regulations
The other applicable environmental regulations for which the O&M Compliance Expenses were incurred are provided in ... Schedule 1 [attached to the direct testimony of] Company witness Spitznogle.

[10] *Id.* (citing the ELG Rule as 40 C.F.R. 423).
[11] *Id.* (citing 18 C.F.R. 4 and VA DEQ § 401).
[12] *Id.* (citing 85 Fed. Reg. 23,054).
[13] *Id.* (citing Code § 10.1-1330 and 9 VAC 5-140).

Mr. Beam identified two central purposes of the Petition:

1. To seek recovery of costs related to compliance with state and federal environmental laws and regulations that are applicable to the generation facilities APCo uses to serve its native load obligation; and

2. To ask again the Commission's permission to recover costs from Virginia customers that are necessary to comply with the ELG Rule at Amos and Mountaineer.[14]

According to Mr. Beam, APCo's second request for ELG Rule cost recovery is pursuant to the *2021 E-RAC Order*, which denied recovery of ELG costs from Virginia customers without prejudice and stated that the Company could re-file for approval "should circumstances so warrant."[15] In Mr. Beam's view, the *2021 E-RAC Order* effectively closed Amos and Mountaineer to Virginia customers at the end of 2028, which is the latest these power plants could combust coal, if the necessary modifications for ELG compliance were not made.[16]

Mr. Beam updated the Commission on the outcome of a WVPSC proceeding concerning APCo's CCR and ELG projects. On August 4, 2021, the WVPSC approved APCo's requests for certificates of public convenience and necessity authorizing the CCR and ELG projects at Amos and Mountaineer, as well as a cost recovery mechanism. On October 12, 2021, the WVPSC issued another order that affirmed its earlier holdings and concluded that, given the *2021 E-RAC Order*, West Virginia jurisdictional customers would pay for these ELG projects, and should also receive the benefit of capacity and energy made possible by the ELG projects starting January 1, 2029.[17] Due to the WVPSC rulings and because PJM looks at APCo as a whole for its fixed resource requirement ("FRR") capacity plan, Amos and Mountaineer will continue to be an integral part of APCo's FRR plan and will continue to operate and dispatch past 2028, regardless of the Commission's decision in the instant case.[18] Mr. Beam confirmed that physical construction of the ELG projects did not begin until after the WVPSC's decision.[19]

Mr. Beam described what he believes would be the impact of two alternative outcomes from the instant Commission proceeding – one in which the Commission approves ELG cost recovery and another in which the Commission denies such recovery.

According to Mr. Beam, if the Commission *approves* ELG cost recovery, nothing will change for Virginia customers. Virginia customers would continue to pay for the Virginia jurisdictional share of all investments, including ELG project investments, as well as O&M costs, for Amos and Mountaineer and would continue to receive the benefit of their energy and capacity as long as the plants continue to run. APCo initially estimated the cost Virginia customers would pay for their share of ELG investment is approximately $15 million the first

[14] Ex. 11 (Beam direct) at 3.
[15] *Id.*
[16] *Id.* at 4.
[17] *Id.* at 3-4 (citing Exs. 17, 18).
[18] Ex. 11 (Beam direct) at 4, 9. For purposes of APCo's capacity position, PJM Interconnection, LLC ("PJM") views APCo as a whole. *Id.* at 9; Tr. at 94 (Beam).
[19] Tr. at 89 (Beam)

year and $150 million in total through 2040 for depreciation and return.[20] Absent a complicated interstate and intracompany arrangement, the Company estimated that Virginia customers would avoid:

- Paying $3 billion or $4 billion for 2,700 megawatts ("MW") or more of nameplate replacement capacity to be in place by 2028, which could increase APCo's cost of service by an incremental 17-21% in 2029 over 2021 payments;

- Being responsible for a revenue requirement for that replacement capacity in the amount of $1.8 billion to $2.35 billion from 2029-2040, compared to a $1.0 billion incremental cost of keeping Amos and Mountaineer operating through 2040. This assumes that APCo could construct and/or procure that much capacity in the pre-2028 timeframe; and

- Possibly being subject to the uncertainty and volatility of capacity provided solely by the market (paper capacity).[21]

Mr. Beam concluded that approval of ELG project cost recovery from Virginia customers would have no effect on APCo's compliance with the Virginia Clean Economy Act ("VCEA").[22] APCo will continue to comply with statutory mandates to seek Commission approval to own renewable facilities, enter into renewable power purchase agreements ("PPAs"), and otherwise procure and retire renewable energy certificates ("RECs"). He stressed that the VCEA places no restrictions on Amos and Mountaineer's energy production and that the VCEA's renewable energy mandates are based on a percentage of energy load (not generation). He also pointed out that until 2035 the total unforced capacity ("UCAP") provided by the renewable resources planned for VCEA compliance is less than the amount of capacity needed to offset even the smallest Amos unit.[23]

According to Mr. Beam, if the Commission instead *denies* ELG cost recovery, Virginia customers would avoid the O&M expenses and capital investment necessary for operations beyond 2028.[24] However, he believes Virginia customers would be more exposed to volatility in the PJM energy market, which is overwhelmingly fossil-based, and would likely still rely on Amos and Mountaineer for capacity, but in a more convoluted way.[25] He believes an equitable arrangement could be made whereby Virginia customers pay for the capacity provided by one or both of these plants. This arrangement could take many forms, would be complicated, and would require approval in West Virginia and Virginia.[26] In addition to the costs for such a

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[20] Ex. 11 (Beam direct) at 5. Mr. Beam's estimate was based on projected total company ELG costs of approximately $197 million combined for Amos and Mountaineer. This estimate was subsequently updated to $169 million. Ex. 8 (Sherrick direct) at 9; Tr. at 63-64 (Sherrick).

[21] Ex. 11 (Beam direct) at 5-6.

[22] 2020 Va. Acts chs. 1193, 1194.

[23] Ex. 11 (Beam direct) at 6.

[24] *Id.* at 7. He believes this would shift a disproportionate share of costs to West Virginia. *Id.*

[25] *Id.* Mr. Beam noted that at noon on March 14, 2022, which he indicated was a relatively clear and sunny day across PJM, renewables accounted for only 12,324 MW of the 98,829 MW of load. *Id.*

[26] *Id.*

2025-00035

potential transaction, Mr. Beam believes it would be fair, and in line with traditional utility practice, for Virginia customers to continue to be responsible for the undepreciated balance of Amos and Mountaineer.[27] He indicated that the Commission has approved the investments that comprise this net book value in the past and if the Commission decides to cease to invest in these assets, APCo would view the remaining Virginia jurisdictional net book value of Amos and Mountaineer as a "stranded cost" for which Virginia customers would be responsible.[28]

Mr. Beam acknowledged that APCo could "theoretically" buy an equivalent amount of capacity from the PJM market, which he indicated would likely be fossil-fueled. He found the acquisition or construction of an equivalent amount of renewable resources to replace the Virginia jurisdictional share of capacity an option that is unlikely to be accomplished by 2028, given the time needed to site, permit, and procure that amount of capacity. This option is complicated by PJM's recent proposal for a two-year pause in reviewing generator interconnection projects due to a backlog of 1,200 proposed projects (mostly solar). In his opinion, these replacement capacity options would involve significant cost to Virginia customers, as West Virginia is unlikely to pay for investment not needed to serve them.[29]

Mr. Martin provided an analysis comparing investment in the ELG projects to an option that assumes Amos and Mountaineer are not available to Virginia customers beyond 2028. He believes his analysis demonstrates that continued operation of Amos and Mountaineer, even if they do not run at all, is less expensive and much less risky for customers than retiring them early and replacing them. He summarized the results of his analysis as follows:

1. The relatively small $98 million[30] jurisdictional share of the ELG investments and continued use of Amos and Mountaineer will be much less expensive than replacing them with billions of dollars of new resources;

2. Replacement capacity would increase customers' rates by an incremental 17-21% in 2029;

3. In total, between 2029 and 2040, the net cost of service for the replacement resources would be between $2.8 billion and $3.4 billion, compared to a $1.0 billion incremental cost of keeping Amos and Mountaineer operating; and

4. The above is true even if Amos and Mountaineer do not generate a single megawatt-hour ("MWh") of electricity after 2028.[31]

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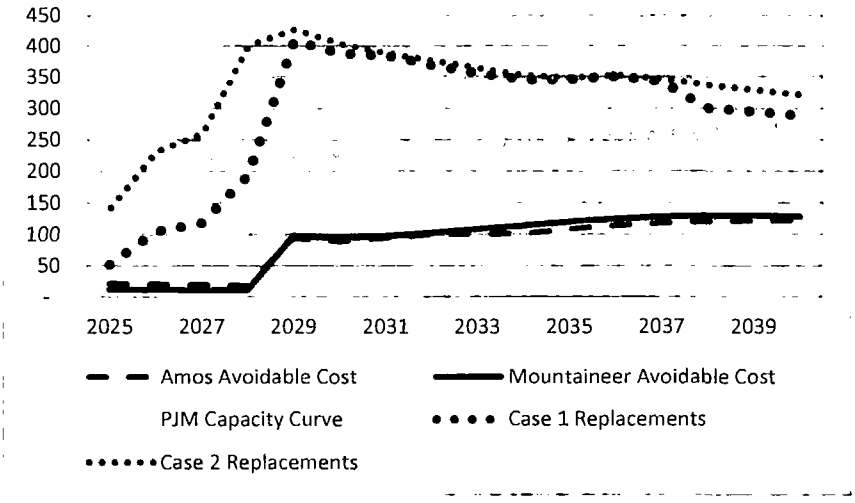
[27] *Id.* at 8. As discussed below, Company witness Ross provided projected book values for such balances.
[28] Tr. at 98-99 (Beam). *See also* Ex. 12 (APCo's responses to Consumer Counsel discovery request nos. 1-04, 1-06).
[29] Ex. 11 (Beam direct) at 8-9.
[30] The $98 million share amount was based on projected total company ELG costs of approximately $197 million combined for Amos and Mountaineer. The $197 million estimate was subsequently updated to $169 million. Tr. at 63-64 (Sherrick).
[31] Ex. 13 (Martin direct) at 3-4. While this page of Mr. Martin's testimony references electricity after 2029, his analysis assumed no energy margin after 2028. *Id.* at 14.

Mr. Martin's analysis in this case took the outputs of analysis APCo conducted in the VCEA renewable portfolio standard ("RPS") Proceeding[32] in the fall of 2021, then adapted those outputs to this case shortly before the Petition was filed.[33] He compared the continued operation of Amos and Mountaineer (future fixed O&M and capital expenses) against two different "cases" of replacement resources – Case 1, which assumes a mix of renewables and gas-fired resources; and Case 2, which assumes 100% renewable and energy storage resources – and also against a projected PJM capacity market price.[34] More specifically, the Case 1 and Case 2 resources used in Mr. Martin's analysis are resources selected by PLEXOS modeling in two of the resource plan scenarios included in the Company's 2021 RPS Plan.[35] He added up the resources through 2028 in the two resource portfolios included in APCo's 2021 RPS Plan that assumed a 2028 retirement of Amos and Mountaineer.[36] His Case 1 in the instant proceeding corresponds to RPS Portfolio 3, while his Case 2 corresponds to RPS Portfolio 4.[37]

Mr. Martin presented the "gross capacity costs" and "net capacity costs" for these alternatives using dollars per megawatt-day ("$/MW-day") as the Y-axis for the figures below.[38]

Figure 1 - Gross Capacity Costs - $/MW-Day



[32] *Petition of Appalachian Power Company, For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia and related requests*, Case No. PUR-2021-00206, Final Order on Petition and Associated Requests, and Order Bifurcating Proceeding (July 15, 2022) ("2021 RPS Proceeding").

[33] Tr. at 104-05 (Martin).

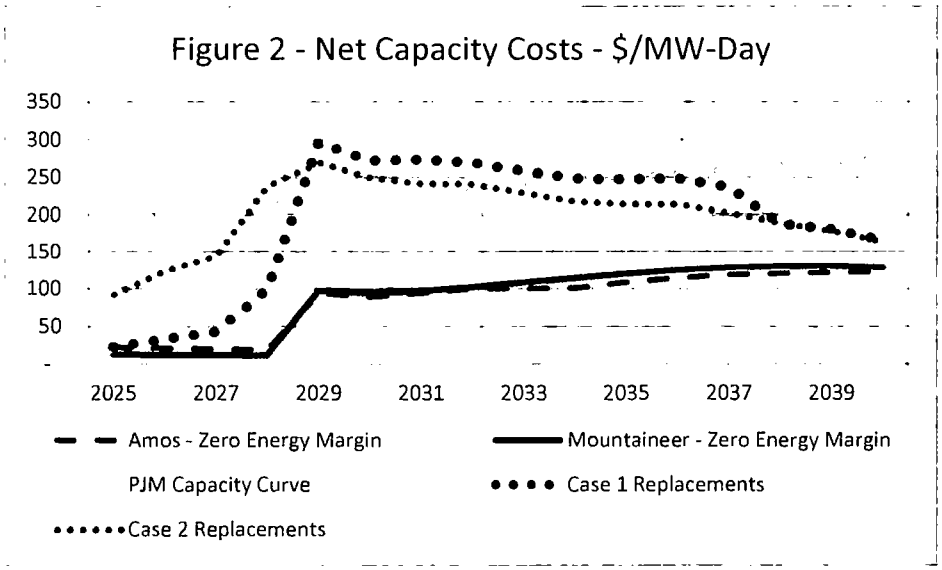
[34] Ex. 13 (Martin direct) at 4-5.

[35] *Id.* at 10. He attached the Company's 2021 RPS Plan to his direct testimony. *Id.* at attached Sched. 1. While the record identifies this plan and its portfolios as "RPS," "VCEA," or "VCEA RPS" plans/portfolios, this Report refers to such as "RPS Plan(s)" or "RPS Portfolio(s)" for consistency.

[36] *Id.* at 11. APCo's 2021 RPS Plan presented six VCEA-compliant portfolios. *Id.* at 10.

[37] *Id.* at 11. These plans show resource additions through 2040. *Id.* at attached Sched. 1, Tables 26 and 27.

[38] *Id.* at 5-6. Mr. Martin testified that the $/MW-Day metric is a common measure of the cost of capacity that puts differently sized capacity resources "on an apples-to-apples" basis as a cost per unit of capacity. *Id.* at 7.



The first year shown on the above figures is 2025, which is the year most of the new resources used for near-term VCEA compliance are projected to come online. The last year shown is 2040, the year through which the WVPSC indicated the ELG projects would provide Amos and Mountaineer an opportunity to run.[39] The difference between Figures 1 and 2 shown above is that Figure 2 deducts an energy margin from the costs of the Case 1 and Case 2 resources. While Mr. Martin indicated that Amos and Mountaineer will generate energy margin, meaning their lines in Figure 2 would be lower if such margins were included, he did not deduct any energy margin for these two plants in Figure 2.[40] He likened the "gross capacity cost" in Figure 1 to base rate cost of service, containing the incremental fixed costs of each option net of tax credits for wind and solar resources.[41]

According to Mr. Martin, the Virginia jurisdiction continues to be responsible for its share of APCo's overall capacity obligation. As that overall obligation will continue to be met, in large part, with Amos and Mountaineer (which would continue to operate beyond 2028 regardless of the outcome of this proceeding), Virginia customers could satisfy their responsibility with an interjurisdictional financial agreement, or conceivably, self-supply of the Virginia capacity obligation.[42]

Mr. Martin provided additional details on his comparative economic analysis. His analysis eliminated all impacts of separate and unrelated resource additions or retirements occurring after 2028. For the replacement resources, he believes the costs and revenues associated with resources added after 2028 are irrelevant to the ELG approval, because they will "come too late to avoid paying for the required pre-2028 investments."[43] Additionally, he assumed 1,907 MW UCAP as the replacement capacity for Virginia. He calculated this amount

[39] *Id.* at 7.
[40] *Id.* at 5. He indicated the assumed PJM market capacity option would not come with any energy margin offset. *Id.* at 6.
[41] *Id.* at 7.
[42] *Id.* at 8.
[43] *Id.* at 9.

by: (1) adjusting the combined 4,200 MW nameplate capacity of Amos and Mountaineer to a 3,814 MW UCAP figure, to account for a forced outage rate; and (2) then taking 50% of the 3,814 MW UCAP figure (approximately 3% Commonwealth and Public Authorities customers added to the approximately 47% Virginia retail jurisdiction).[44] He estimated the Virginia jurisdictional share of ongoing avoidable costs of Amos and Mountaineer, including the ELG projects, combined would average $84 million annually, from 2029-2040.[45] His analysis excluded recovery of sunk costs of the existing investment in these plants from Virginia customers, because he believes such costs would be recovered in any scenario.[46]

To meet the 1,907 MW UCAP his analysis in the instant case assumes APCo would need to replace the Virginia jurisdictional share of Amos and Mountaineer, he made the following assumptions:

1. If approved, the mixture of owned and PPA wind and solar projects that were selected from the 2021 RFP totaling 498 MW proposed in the 2021 RPS Proceeding will come online at various dates between 2023 and 2025. He assumed both Virginia and West Virginia would approve the projects, and Virginia would thus be allocated half;

2. The next group of resources added between 2025 and 2028 were assumed to be fully allocated to APCo's Virginia jurisdiction to meet the VCEA requirements. Between steps 1 and 2, all of the resources required by the VCEA prior to 2028 have been brought into the analysis, reducing the replacement capacity that would otherwise be required to replace Amos and Mountaineer; and

3. The "plug" to fully replace the remaining portion of Virginia's half of Amos and Mountaineer's UCAP capacity was then taken from the large resource added to replace these plants in 2028. This is a gas combined cycle plant in Case 1 and energy storage in Case 2.[47]

He presented tables showing the resource composition and costs of Cases 1 and 2 in his analysis.[48] Both tables are included below in Section I of this Report's Analysis.

Mr. Martin also analyzed a "paper capacity" alternative of purchasing capacity at a forecasted PJM market price, which is identified in the record as his "Case 3." He testified that this approach would leave APCo heavily exposed to both market energy and capacity price risks that would be mitigated with ownership of actual resources.[49]

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[44] *Id.* at 9-10.
[45] *Id.* at 10. He estimated $73 million of avoidable costs in 2029 increasing to $95 million in 2040. *Id.*; Ex. 4 (Petition) at Filing Sched. 46, Section 2, Statement 1.
[46] Ex. 13 (Martin direct) at 10. He believes such costs would either be: (a) recovered as depreciation should Amos and Mountaineer continue to run; or (b) amortized over a given period if these plants are replaced. *Id.*
[47] *Id.* at 12.
[48] *Id.* at 13.
[49] *Id.* at 9, 11.

Mr. Martin sponsored Filing Schedule 46, Section 2, Statement 1, which displays the results of his economic analysis for each year, from 2029 to 2040. Mr. Martin summarized the results of his economic analysis over the entire period using the following table.[50]

Table 3 - 2029-2040 Cost of Service Impacts

Line	Dollars In Millions	NPV of 2029-2040	Nominal Total 2029-2040
1	**Amos and Mountainer incremental capacity cost**	$647	$1,003
	Replacement Capacity Costs, net of Energy Margin		
2	Case 1 - Gas CC and Renewable Replacements	$1,935	$2,825
3	Case 2 - Storage and Renewable Replacements	$2,290	$3,356
4	Paper Capacity - PJM Market	$1,486	$2,280
	Replacement Cost Percentage of Amos/Mountaineer	2029-2040 Average % Increase	2029-2040 Average $(Millions) Increase
5	Case 1 - Gas CC and Renewable Replacements	290%	$152
6	Case 2 - Storage and Renewable Replacements	344%	$196
7	Paper Capacity - PJM Market	229%	$106

Mr. Martin detailed some of the assumptions in his economic analysis. For Amos and Mountaineer, he used an approximately $98 million Virginia share of ELG investments[51] to calculate a $15 million annual revenue requirement paid by Virginia customers when the ELG investments go in service, dropping to $2 million per year in 2034.[52] Over the entire period between 2022 and 2040, he estimated the Virginia share of the nominal revenue requirement will total approximately $150 million, with an approximately $93 million present value of this cost-of-service estimate.[53]

For both cases, Mr. Martin included all future non-ELG capital investment at Amos and Mountaineer forecasted through 2035. From 2036 to 2040, he used a "glide path" capital expense forecast with reduced maintenance capital. Starting in 2029, he applied a levelized

[50] *Id.* at 16.
[51] Mr. Martin's $98 million Virginia share assumption was based on projected total company ELG costs of approximately $197 million combined for Amos and Mountaineer. This estimate was subsequently updated to $169 million. Tr. at 63-64 (Sherrick).
[52] Ex. 13 (Martin direct) at 18. He assumed the Amos ELG is fully depreciated in 2033, with the remaining depreciation related to Mountaineer ELG. *Id.*
[53] *Id.* at 18-19.

carrying charge to this capital expense to determine the cost-of-service savings from avoiding that capital.[54]

His analysis assumed the currently forecasted level of O&M through 2030. After 2030, O&M was assumed to decline to 75% of the 2030 forecast, due to lower capacity factors, if a national carbon tax is enacted. All of the fixed O&M was assumed to be avoidable starting in 2029.[55]

He also prepared a forecast of taxes that could be avoided if Virginia customers no longer benefit from Amos and Mountaineer. APCo is expected to pay approximately $10 million in property taxes and $36 million in West Virginia business and occupation taxes annually towards the end of this decade. Virginia's half of these two taxes would be approximately $23 million annually in 2028 and beyond.[56]

For the replacement resources, he used a spreadsheet to calculate a forecast of the annual revenue requirement on the new resource additions using customary ratemaking principles. For owned resources, he used a forecasted rate base that declines over time, return on rate base at a weighted average cost of capital, depreciation, O&M, production tax credits over the first ten years of the wind assets, and normalization of investment tax credits on solar assets over a 35-year life. He used PPA costs for PPAs. He used actual resource costs for the portion of replacement capacity provided by the Virginia half of the 498 MW of the VCEA-compliant projects proposed in the 2021 RPS Proceeding. According to Mr. Martin, the gross cost of service for this 498 MW is projected to average approximately $42 million per year for Virginia customers through 2040.[57] He summarized these resources with the following table.[58]

TABLE 5 – Near Term Planned Resources

Facility	Nameplate Capacity MW	Owned / PPA	State	Resource Type	Operation
Firefly	150.0	Owned	Virginia	Solar	July 2024-June 2059
Amherst*	4.9	Owned	Virginia	Solar	Jan 2023 - Dec 2057
Horsepen	20.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Dogwood*	18.9	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Sun Ridge	50.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Virginia Domiciled	**243.8**				
Top Hat	204.0	Owned	Illinois	Wind	Jan 2025 - Dec 2054
Bedington	50.0	Owned	West Virginia	Solar	Oct 2023 - Sep 2058
TOTAL	**498**				

*Distribution Resource

For the remaining replacement resources, Mr. Martin used generic resource costs, including wind and solar costs aligned with the average of the bids received by APCo in RFPs it

[54] *Id.* at 19.
[55] *Id.* at 19.
[56] *Id.* at 19-20.
[57] *Id.* at 20.
[58] *Id.* at 21.

issued for both owned and PPA resources in 2021. As such, all new wind and solar resource costs are based on actual market information available when the analysis was performed.[59]

Mr. Martin testified that PJM utilities like APCo are required to provide enough capacity to cover their summer peak loads plus a reserve margin forecasted to be 14.9% on an installed capacity or nameplate basis, or approximately 8.6% on a UCAP basis.[60]

Mr. Martin explained that PJM assigns capacity values lower than nameplate ratings. In addition to adjusting each resources' nameplate capacity downward for an assumed forced outage rate, the capacity credit of intermittent, renewable resources is based on the effective load carrying capability ("ELCC") methodology.[61] He provided the following table to illustrate how much more nameplate capacity is required for intermittent resources to match the UCAP value of Amos and Mountaineer.[62]

Table 4 - PJM Capacity Credit By Resource Type

	Nameplate Capacity	2028 PJM Capacity credit %	PJM Accredited UCAP Capacity	Capacity to Match Amos / Mountaineer UCAP
50% of Amos and Mountaineer	2,100	91%	1,907	
Wind	2,100	11%	231	17,336
Solar (Tracking)	2,100	39%	819	4,890
Storage - 4 hour	2,100	70%	1,470	2,724
Solar Plus 4 hour Storage	2,100	72%	1,512	2,649
Gas CT or CC	2,100	96%	2,016	1,986

As shown, for example, approximately 4,890 MW of nameplate solar (tracking) or 17,336 MW of nameplate wind is equivalent to the 2,100 MW nameplate capacity of 50% of Amos and Mountaineer.

Based on current ELCC expectations, and a mix of 40% wind and 60% solar, 8,800 MW of such resources would be needed by 2028 to replace the 1,907 MW of UCAP for the Virginia share of Amos and Mountaineer, at a cost close to $15 billion.[63] For these replacement resources, Mr. Martin calculated an approximately $338 million annual average net cost of service through 2040 by assuming the cost of the generic resources would be the same as the expected cost of the 498 MW proposed in the 2021 RPS Proceeding, after deducting expected energy revenue that will reduce customer fuel costs. The 8,800 MW of replacement resources needed by 2028, according to his calculations, is 17.7 times the 498 MW proposed in the 2021 RPS Proceeding. Mr. Martin multiplied the $19 million per year average cost estimated for

[59] *Id.*
[60] *Id.* at 16-17.
[61] *Id.*
[62] *Id.* at 18.
[63] *Id.* at 22.

the 498 MW times 17.7 to calculate his $338 million annual average net cost of service for 8,800 MW of replacement resources.[64]

Mr. Martin also calculated projected annual and average costs per MWh energy of ten new resources, including the seven resources proposed in the 2021 RPS Proceeding plus three other PPA resources that went online in 2021 or that will go online in 2022.[65] He calculated the cost of these ten resources to average $53/MWh over the 17 years between 2024 and 2040.[66]

Mr. Martin described the growing influence of REC values on new resource costs. He reported that PJM REC prices traded as high as $24.50 in January 2022. In the two RPS Portfolios on which his Case 1 and Case 2 analysis is based, REC prices were assumed to be between $27 and $32 between 2023 and 2031.[67] He explained that state renewable energy mandates and corporate renewable pledges have created a high demand for renewables and RECs, leading to difficulty getting resources sited, interconnected, approved, and constructed in time to meet growing compliance targets. He recognized that PJM is seeking to implement a two-year moratorium on new interconnection requests due to its interconnection queue backlog. All of this has driven up REC prices and PPA prices, according to Mr. Martin.[68]

To comply with the VCEA, APCo must self-generate or purchase and retire RECs. For PPAs, Mr. Martin indicated the REC value can push up the PPA price to an amount "well above" the cost of the underlying asset. In his opinion, the REC value that rational profit-seeking developers attempt to capture in pricing their product will increase a new resource price above the cost of the asset itself.[69]

While APCo must meet REC/RPS requirements and petition the Commission for approval of certain resources, Mr. Martin recognized that the VCEA does not require the retirement of Amos or Mountaineer, which are located outside of Virginia. He indicated the petition requirements applicable in time to impact the ELG decision are 400 MW of wind or solar by 2027 and 25 MW of storage by 2025. He does not believe any resources added for VCEA compliance after the 2027 requirement are relevant to the decision regarding how to replace Amos and Mountaineer's capacity, as that decision would have already been made.[70]

Mr. Martin explained that APCo is not projected to need capacity to maintain compliance with PJM capacity requirements until 2040 and APCo plans to add only the minimum resources needed for VCEA compliance (assuming they are cheaper than RECs). The total UCAP

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[64] *Id.* *See also* Tr. at 277-78 (Martin) (providing additional detail on how the 108 MW UCAP figure was calculated for the 498 MW of resources).
[65] Ex. 13 (Martin direct) at 22. The other PPA resources are Wytheville (20 MW), Leatherwood (20 MW), and Depot (15 MW). *Id.* at 22-23.
[66] *Id.* at 22. The lowest cost during this period is $47/MWh. *Id.*
[67] *Id.* at 23 and attached Sched. 1, Section 4.3.5.
[68] *Id.* at 23.
[69] *Id.* at 24.
[70] *Id.* at 24-25. APCo must petition for 200 additional MW of wind or solar by 2030 and 125 additional MW of storage by 2030. *Id.* at 25.

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provided by all the new resources APCo plans to add for VCEA compliance by 2028 is 298 MW, which is less than half of the 742 MW UCAP capacity of the smallest unit at Amos.[71]

Mr. Martin indicated that the VCEA requirements do impact the economics of Amos and Mountaineer. However, as the VCEA's REC/RPS requirement is a percentage of Virginia jurisdictional load, the VCEA does not restrict how much Amos and Mountaineer can operate.[72]

As for potential transmission costs, APCo's decision to make CCR and ELG investments factored in a high-level estimate of approximately $100-$200 million in needed transmission upgrades if Amos and Mountaineer were retired. However, Mr. Martin's economic analysis in the instant case includes no transmission costs because Amos and Mountaineer will not retire in 2028. He also did not add interconnection costs beyond routine interconnection costs assumed in the generic resources. However, he maintained that based on the interconnection costs of adding the 498 MW of resources currently under development, the transmission costs for the thousands of nameplate MW needed to replace Virginia's half of Amos and Mountaineer could be $50-$100 million, depending on the location of replacement capacity. Such costs, if included, would raise the replacement cost calculated in his analysis.[73]

Turning to the gas-fired Clinch River power plant, Mr. Martin explained that RGGI compliance costs are required because Clinch River is located in Virginia. Such costs have been deferred to date, and Company witness Castle included an estimate of such costs in the proposed revenue requirement in the instant case. Mr. Martin testified that RGGI cost recovery is appropriate since customers have already received a fuel cost-of-service reduction from the energy revenues received when Clinch River's energy was economically dispatched. He testified that when APCo offers Clinch River for sale into the PJM energy market, the offered price includes the cost of any RGGI allowances that APCo would need to purchase to allow Clinch River to run.[74]

While Mr. Martin testified that he knows a cost of RGGI allowances is included in APCo's offers into the PJM energy market, he did not know how APCo develops the number that is incorporated into the offer. He testified that his view of "economic dispatch" involves "blocks" of time (not necessarily individual hours) when the energy market price is higher than a unit's dispatch cost bid by APCo.[75] Discovery responses he provided to Appalachian Voices indicated that APCo uses RGGI CO_2 allowance prices published in Argus Air Daily to estimate the costs of RGGI allowances when preparing Clinch River's hourly offer curves.[76]

Mr. Martin also provided discovery responses about the self-scheduling of Clinch River that were admitted into the record, which are discussed further in Section III of this Report's Analysis.

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[71] *Id.* at 25.
[72] *Id.* at 26.
[73] *Id.* at 27.
[74] *Id.* at 28. RGGI membership requires one allowance for every ton of CO_2 produced by applicable electric generation in Virginia. Ex. 9 (Spitznogle direct) at 16.
[75] Tr. at 107-09 (Martin).
[76] Ex. 14 (APCo's response to Appalachian Voices' discovery request no. 2-01).

Mr. Sherrick sponsored most of Sections 1 and 2 of Filing Schedule 46.[77]

Mr. Sherrick described the CCR/ELG projects at Amos and Mountaineer. He explained that all four units at these plants (three units at Amos and one at Mountaineer) are equipped with an electrostatic precipitator for control of particulate matter, an FGD system for sulfur dioxide control, both SCR technology and low-nitrogen oxygen ("NOx") burners for control of NOx emissions, and a dry fly ash handling system. All four units currently transport bottom ash and miscellaneous wastewater streams to a pond system where the bottom ash is later dredged and trucked to a permitted landfill. The bottom ash transport water and miscellaneous wastewater streams are then discharged to the Kanawha (Amos) and Ohio (Mountaineer) Rivers through a national pollution discharge elimination ("NPDES") permitted outfall.[78]

Mr. Sherrick explained that the *2021 E-RAC Order* approved cost recovery for CCR projects for Amos and Mountaineer. He described the CCR/ELG project scopes and how APCo determined them through collaboration with several departments of AEPSC.[79] For Amos to operate in compliance with the CCR/ELG requirements requires:

(i) removing ash from the Bottom Ash 1A and 1B, Reclaim, and Clearwater ponds;
(ii) closing pond 1A and grading and seeding to establish natural drainage;
(iii) lining the existing Reclaim and Clearwater ponds;
(iv) constructing a new Lined Wastewater pond in place of Bottom Ash Pond 1B;
(v) installing a chemical treatment system for non-CCR wastewater streams;
(vi) modifications to the bottom ash handling systems to no longer allow the discharge of bottom ash transport water, including the installation of submerged grind conveyor systems;
(vii) installation of two new ash bunkers;
(viii) retrofitting economizer ash handling systems on Units 1 and 2; and
(ix) installation of a new FGD Biological Treatment System with Ultrafiltration.[80]

For Mountaineer to operate in compliance with CCR/ELG requirements requires:

(i) removing ash from the east and west Bottom Ash ponds;
(ii) lining the cleaned east and west ponds to create east and west Wastewater Settling ponds;
(iii) installing a chemical treatment system for non-CCR wastewater streams;

[77] Mr. Gallimore sponsored one page. Ex. 4 (Petition) at Filing Sched. 46, Section 1, Statement 1 – Claytor DO Project Cost Estimate. Mr. Martin sponsored a one-page summary for his economic analysis. *Id.* at Filing Sched. 46, Section 2, Statement 1.
[78] Ex. 8 (Sherrick direct) at 3.
[79] *Id.* at 3-4.
[80] *Id.* at 4.

(iv) potentially installing ground water remediation equipment;
(v) modifications to the bottom ash handling system to no longer allow discharge of bottom ash transport water, including installation of a submerged grind conveyor system;
(vi) installation of a new ash bunker; and
(vii) retrofit of a new Ultrafiltration system onto the existing FGD Biological Treatment System.[81]

According to Mr. Sherrick, AEPSC evaluated different vendor options to convert the wet bottom ash handling systems to dry systems and to treat the FGD wastewater streams. AEPSC also evaluated closed loop recycle systems for Amos. The project teams selected the technically feasible, least life-cycle-cost option for APCo's customers.[82]

Mr. Sherrick described AEP's process for planning and constructing environmental projects, including AEPSC's project schedule management process.[83] He sponsored the schedules for the Amos and Mountaineer compliance plans.[84]

Mr. Sherrick described the cost estimates for the CCR/ELG projects he supplied to Company witness Martin for his economic analysis. Cost estimates were developed by an independent engineering firm with inputs and oversight from AEPSC,[85] and updated at the hearing to reflect project completion as of August 2022 based on the close of the July business month.[86] At Amos, the current total estimated cost is $179 million, of which approximately $127 million is associated with only ELG compliance. At Mountaineer, the current total estimated cost is $79 million, of which approximately $42 million is associated with only ELG compliance.[87]

Mr. Sherrick explained that APCo's current cost estimates for the Amos and Mountaineer CCR component are $7 million and $19 million higher, respectively, than the estimates provided in the 2021 E-RAC Case. He attributed increased estimates to quantity increases from preliminary to detailed engineering and design, material price changes due to the coronavirus pandemic, and contractor unit prices that were higher than estimated. Before decreased estimates were identified at the hearing, APCo's cost estimates for the Amos and Mountaineer

[81] *Id.* at 5.
[82] *Id.*
[83] *Id.* at 5-9.
[84] *Id.* at 2; Ex. 4 (Petition) at Filing Sched. 46, Section 2, Statement 2 – Amos Project Schedule; *Id.* at Filing Sched. 46, Section 2, Statement 2 – Mountaineer Project Schedule.
[85] Ex. 8 (Sherrick direct) at 9-10. *See also* Ex. 4 (Petition) at Filing Sched. 46, Section 2, Statement 2 – Amos, and Statement 2 – Mountaineer.
[86] Tr. at 63 (Sherrick).
[87] Ex. 8 (Sherrick direct) at 9-10; Tr. at 63-64 (Sherrick). The $179 million total cost estimate for Amos includes $160 million in capital, $6.3 million in other charges, and $13 million in asset retirement obligation ("ARO") costs. *Id.* at 9; Tr. at 63 (Sherrick). The $79 million total cost estimate for Mountaineer includes $71 million in capital, $4.8 million in other charges, and $3.4 million in ARO costs. *Id.* at 9-10; Tr. at 64 (Sherrick). *See also* Ex. 4 (Petition) at Filing Sched. 46, Section 1, Statement 1, Amos Project Cost Estimate, p. 1, and Mountaineer Project Cost Estimate, p. 1.

ELG component were $16.4 million and $4.4 million higher, respectively, than the estimates provided in the 2021 E-RAC Case.[88]

Mr. Sherrick provided an update on the status of the CCR and ELG projects. At the time the Petition was filed, construction of the Amos CCR system was ongoing, with removal of bottom ash and closure by removal of existing pond 1B. Construction of the Mountaineer CCR system began in March 2022.[89] Through August 2021, the Amos and Mountaineer ELG projects incurred approximately $19.5 million and $12.6 million, respectively, in ELG costs for Stages 1 through 3 activities. Mr. Sherrick asserted that incurrence of these costs prior to regulatory approval was unavoidable as they were necessary to establish the projects' scope, schedule, and cost estimates to inform the regulatory process.[90] Costs incurred after August 2021 included costs to finish the permitting process, install dry bottom ash and wastewater treatment equipment, and startup and commission installed systems. Mr. Sherrick indicated these activities are required to meet environmental compliance deadlines.[91]

Mr. Sherrick also described the Amos Units 1 & 2 dry sorbent injection project, which would reconfigure the existing system to handle hydrated lime more efficiently, at an estimated cost of $9.4 million. This project would reduce issues related to corrosion, improve heat rate, improve equivalent unplanned outage rate, lower minimum load, and help with the long-term protection of the SCR catalyst, air heaters, and precipitators.[92] The system is scheduled to be retrofitted during fall 2022 unit outages.[93]

At the time of the hearing, Mr. Sherrick reported that all of the relevant projects were either in the construction phase or the startup and commissioning phase.[94]

Mr. Gallimore described the dissolved oxygen project at Claytor, APCo's four-unit hydroelectric facility on the New River in Radford, Virginia.[95] As approved by FERC and the Virginia DEQ, APCo would replace current turbines with auto-venting turbines in two of the four generating units. Each of these two units would independently meet the dissolved oxygen requirements, which provides redundancy – a factor Mr. Gallimore indicated was key to the Company's selection of this compliance option.[96] Auto-venting technology is a proven, reliable technology that provides the greatest percentage of increased dissolved oxygen concentration,

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[88] Ex. 8 (Sherrick direct) at 10; Tr. at 64 (Sherrick).
[89] Ex. 8 (Sherrick direct) at 11.
[90] *Id.* The Stage 1 through 3 activities include project initiation, technology feasibility studies, evaluation of risk balanced technical options, conceptual engineering, permitting, and site investigations. *Id.* According to Mr. Sherrick the significance of August 2021 is that it is when WVPSC issued the order approving ELG investment. Tr. at 67 (Sherrick).
[91] Ex. 8 (Sherrick direct) at 11-12.
[92] *Id.* at 12. *See also* Ex. 4 (Petition) at Filing Sched. 46, Section 1, Statement 1 – Amos Units 1 & 2 DSI Estimate (providing a cost breakdown).
[93] Ex. 8 (Sherrick direct) at 13.
[94] Tr. at 67 (Sherrick).
[95] Ex. 6 (Gallimore direct) at 2.
[96] *Id.* at 3. In addition to redundancy, units 3 and 4 were proposed because they have the same manufacturer and are situated closest to the centerline of the tailrace (the water channel below the dam). *Id.*

and is expected to increase the MW output of each unit by at least 10% because of the turbine design.[97]

Mr. Gallimore explained that the auto-venting turbine project was selected after receiving bids from vendors in response to a request for information. Construction on the first unit is scheduled to begin in 2022, with a planned in-service date of November 2023. Construction on the second unit is scheduled to begin in 2023, with a planned in-service date of November 2024. The total estimated cost of the project is $12.4 million.[98]

According to Mr. Gallimore, APCo worked with an independent engineering firm to evaluate dissolved oxygen enhancement options for Claytor. One alternative option was to install a line diffuser in the forebay (upstream) pond of Claytor. This option would require oxygen storage and additional oxygen generation equipment to be installed on site, with on-site storage needed as a backup. This option would require annual maintenance, which would increase the annual cost to operate and maintain the line diffuser. Additionally, the diffuser would be subject to damage and blockage from lake debris, which would prevent the enhancement to dissolved oxygen levels while the system is out of service.[99] Mr. Gallimore asserted that the auto-venting turbine project is the best, most reliable solution available.[100]

Mr. Spitznogle described the environmental regulations that drive the need and timing for the environmental improvement projects at APCo's generation facilities. He also supported the identification of activities: (i) related to the handling and disposal of the byproducts of coal combustion necessary for state or federal legal compliance; (ii) undertaken at Claytor to comply with dissolved oxygen requirements issued by FERC; (iii) undertaken at Amos to optimize the dry sorbent injection system used to mitigate acid gas emissions; and (iv) to comply with RGGI.[101]

Mr. Spitznogle provided a list of compliance activities to Company witness Ross to identify the environmental compliance costs associated with those activities.[102] Mr. Spitznogle cited the federal or state law(s) or regulation(s) applicable to each environmental project.[103] He used detailed accounting reports that included actual 2021 activities associated with environmental compliance for January through November during that year to identify activities associated with specific pieces of equipment and systems.[104] Mr. Spitznogle believes the level of environmental activity for these eleven months is representative of ongoing levels during the projected period.[105]

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[97] *Id.* at 3-4. *See also* Ex. 4 (Petition) at Filing Sched. 46, Section 2, Statement 2 – Claytor DO Project.
[98] Ex. 6 (Gallimore direct) at 4-5. *See also* Ex. 4 (Petition) at Filing Sched. 46, Section 1, Statement 1 – Claytor Project Cost Estimate.
[99] Ex. 6 (Gallimore direct) at 4-5.
[100] *Id.* at 3-4.
[101] Ex. 9 (Spitznogle direct) at 2-3.
[102] *Id.* at 3. Mr. Ross used accounting reports to identify the compliance expenses and investments incurred for each identified activity. *Id.* at 10.
[103] *Id.* at attached Sched. 1.
[104] *Id.* at 9.
[105] *Id.* at 10.

He described the CCR Rule, which regulates the handling and storage of CCR material – including fly ash, bottom ash, and gypsum – generated at coal-fired generation facilities. The CCR Rule applies to new and existing CCR landfills and surface impoundments (ponds) at operating coal-fired generation facilities. Some requirements of the CCR Rule, including applicable compliance dates, have been revised by the EPA since the initial 2015 regulation. The most recent revisions were finalized in August 2020.[106] In November 2020, APCo filed with the EPA a request to extend the CCR compliance date. At the time of the Petition, the EPA had not ruled on APCo's request.[107]

According to Mr. Spitznogle, activities associated with CCR handling and disposal include, but are not limited to, items such as bottom ash pumps and transportation equipment, economizer ash handling equipment, fly ash handling equipment and disposal activities, gypsum handling and disposal equipment and systems, ponds, and landfills.[108]

Mr. Spitznogle described the ELG Rule, which established discharge limits on FGD wastewater, transport water used for fly ash and bottom ash handling, and other wastewaters at steam-electric generation facilities. The ELG Rule's requirements were revised after the initial 2015 regulation, with the most recent revisions finalized in October 2020. The revised rule eliminated the discharge of most ash transport waters and requires enhanced treatment of FGD wastewaters. These requirements are implemented through modifications to the existing state wastewater discharge (NPDES) permit at each facility.[109] The ELG Rule requires that discharge limits be achieved as soon as possible before December 31, 2025, pursuant to a schedule that will be included in each facility's NPDES permit. New bioreactors would bring Amos to full ELG compliance by the end of 2023 and an upgraded bioreactor would bring Mountaineer into ELG compliance by the end of 2023.[110] Options for compliance with the ELG Rule that APCo did not choose – installation of advanced membrane technology, dispatching at very low capacity factors, or plant retirement – had a 2028 compliance deadline.[111]

Mr. Spitznogle testified that, to expedite compliance, APCo developed coordinated activities needed to comply with the requirements of the ELG Rule and CCR Rule.[112]

Mr. Spitznogle confirmed that the EPA has issued a notice of proposed rulemaking that would require more stringent ELG standards for FGD wastewater. The EPA's proposal references the potential to require advanced membrane technology for FGD wastewater.[113]

Mr. Spitznogle identified the dry sorbent reconfiguration at Amos as an additional environmental compliance project that APCo proposed to include in the E-RAC. He recognized that SCR and FGD systems were installed to comply with NOx and sulfur dioxide ("SO_2") limits under various environmental regulations. The FGD systems at Amos included the addition of a

[106] *Id.* at 4-5.
[107] *Id.* at 6-7.
[108] *Id.* at 9.
[109] *Id.* at 5.
[110] *Id.* at 6-7.
[111] Tr. at 72-73 (Spitznogle).
[112] Ex. 9 (Spitznogle direct) at 6-7.
[113] Tr. at 73-74 (Spitznogle).

dry sorbent injection system to mitigate emissions of SO_3, an acid gas that can cause visible stack emissions as a result of operating the SCR and FGD systems together.[114] Whereas Amos's original dry sorbent injection system was designed to use trona, the system would be modified to use hydrated lime. This modification will result in reduced O&M costs, while continuing to mitigate the emission of acid gas.[115] Mr. Spitznogle clarified that while reconfiguring the dry sorbent system is not required by a specific environmental regulation, reconfiguration will allow for more economic compliance with the regulation that required construction of the dry sorbent injection system.[116]

Mr. Spitznogle discussed the regulations necessitating the dissolved oxygen project at Claytor. Virginia water quality standards include minimum concentration and daily average concentration standards for dissolved oxygen. In 2019, FERC requested that APCo prepare and file a redefined plan to improve low dissolved oxygen conditions at Claytor, given the lack of progress in enhancing water quality conditions over the past seven years. Virginia DEQ recommended APCo explore alternative measures for improving dissolved oxygen concentrations during the June through September periods. In 2020, FERC and Virginia DEQ separately approved APCo's redefined plan providing for such measures at Claytor, including the installation of two auto-venting turbines to aerate water flow by injection of air into the unit discharge.[117]

Mr. Spitznogle discussed the RGGI regional cap, allowances, and auctions used by participating states to regulate CO_2 emissions.[118] He identified the statute that directed the Virginia DEQ to adopt regulations resulting in Virginia's membership in RGGI. He explained that Clinch River – a two-unit, 484 MW gas-fired plant – is APCo's only carbon-emitting generation facility located in Virginia. APCo is required to purchase one CO_2 allowance for each ton of CO_2 emitted from Clinch River.[119]

Mr. Ross testified in support of APCo's accounting treatment for the ash pond updates at Amos and Mountaineer, the dry sorbent injection project at Amos, and the dissolved oxygen project at Claytor. He explained APCo's proposed regulatory accounting and cost recovery for accumulated funds used during construction ("AFUDC"), return on construction work in progress ("CWIP"), plant-in-service, and depreciation expense.[120]

Mr. Ross summarized APCo's total net E-RAC under-recovery as of December 31, 2021, with the following table.[121]

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[114] Ex. 9 (Spitznogle direct) at 10-11. With the addition of the FGD system, Amos began to consume a fuel with higher sulfur content, and a small portion of the resulting SO_2 is converted to SO_3 in the SCR. *Id.* at 11.
[115] *Id.* at 11-12.
[116] Tr. at 75-76 (Spitznogle).
[117] Ex. 9 (Spitznogle direct) at 13-14.
[118] *Id.* at 14-15.
[119] *Id.* at 16.
[120] Ex. 10 (Ross direct) at 13-17.
[121] *Id.* at 4.

APCo E-RAC Under-Recovery – December 31, 2021	
Account 1823618 – VA Unamortized CCR O&M Compliance Expense Deferral	$12,647,325
Account 1823645 – VA Unamortized AFUDC on CCR Construction Expenditures	194,772
Account 1823647 – VA E-RAC Under-Recovery	233,682
Net APCo Virginia E-RAC Under-Recovery – December 31, 2021	**$13,075,779**

Mr. Ross explained that APCo excluded the unamortized balances of Accounts 1823618 and 1823645 (the first two figures in the above table) because those costs will be fully recovered when APCo updates E-RAC rates in December 2022.[122]

According to Mr. Ross, the CCR investments for wastewater pond upgrades at Amos and Mountaineer are expected to be placed in service in October 2023 and December 2023. Once in service, APCo will incur depreciation and return on net assets placed in-service, ARO asset depreciation expense, and ARO liability accretion expense, all of which Mr. Ross indicated would be included in APCo's future monthly E-RAC over-/under-recovery. Mr. Ross also requested Commission approval to prospectively recover property tax expense incurred related to APCo's Virginia retail jurisdictional CCR CWIP and electric plant-in-service balances.[123] As approved in the *2021 E-RAC Order*, APCo will use initial depreciation rates of 9.52% for Amos and 5.71% for Mountaineer for CCR assets that are placed in service, based on average in-service dates of the CCR/ELG projects at these plants.[124]

Mr. Ross reported that APCo began incurring RGGI costs associated with Clinch River in 2021 and had deferred $340,981 of Virginia jurisdictional RGGI costs through December 31, 2021.[125] APCo's proposed E-RAC includes this amount, in addition to forecasted RGGI expense amounts of $158,159 for January 2022 through November 2022 and $300,390 for December 2022 through November 2023.[126] He testified that if actual RGGI costs are less than forecasted RGGI costs, APCo will record the difference and include it in a future E-RAC petition.[127] Mr. Ross indicated that energy revenues referenced in the Company's Petition are credited to the fuel factor, but APCo has not netted any revenues against the deferred RGGI costs.[128]

For ELG investments, APCo proposes recovering AFUDC on CWIP incurred up to December 2022, return on CWIP from December 2022 through the in-service date, depreciation and return on net assets placed in service, and property taxes on CWIP and electric plant-in-

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[122] *Id.* at 5.
[123] *Id.* at 5-7. Mr. Ross indicated that APCo mistakenly omitted requesting recovery of such property tax expense in the 2021 E-RAC Case. *Id.* at 7.
[124] *Id.* at 16. While these proposed depreciation rates do not include a component for net salvage, APCo will request a net salvage factor in future depreciation studies filed by the Company. *Id.*
[125] *Id.* at 7.
[126] *Id.* at 8.
[127] Tr. at 83-84 (Ross)
[128] Tr. at 82 (Ross).

service.[129] APCo currently expects the Amos dry ash handling system and water biological treatment system with ultrafiltration will go in service in December 2022 and September 2023, respectively. APCo expects the Mountaineer dry ash handling system and upgraded water biological treatment system with ultrafiltration will go in service in May 2022 and June 2023, respectively.[130] Once in service, APCo proposes using the same depreciation rates for ELG assets as proposed for CCR assets (*i.e.*, 9.52% for Amos and 5.71% for Mountaineer).[131]

If the Commission rejects recovery of Amos and Mountaineer ELG investments in the instant case, APCo would propose changes to existing depreciation and recovery of the remaining base generating units. Current depreciation and recovery are based on APCo's 2019 Virginia depreciation study, as modified and approved by the Commission in the 2020 Triennial Review.[132] This study established depreciation rates using estimated retirement dates of 2032 for Amos Units 1 and 2, 2033 for Amos Unit 3, and 2040 for Mountaineer.[133] As of December 31, 2021, APCo projected December 31, 2028 total company Amos and Mountaineer book values of approximately $582 million and $474 million, respectively. Mr. Ross clarified that these forecasted balances: (a) were determined using APCo Virginia retail ratemaking adjustments consistent with prior APCo Virginia base case filings; (b) include CCR investments; (c) exclude ELG investments; and (d) exclude other Amos and Mountaineer base generating unit capital expenditures for the period 2022 through 2028.[134]

If the Commission rejects recovery of ELG investments, APCo requests recovery of approximately $15.3 million of CWIP and $0.5 million of AFUDC on ELG CWIP balances through August 2021, when the *2021 E-RAC Order* was entered.[135]

Mr. Ross indicated that APCo is currently incurring construction costs for the dry sorbent injection project at Units 1 and 2 of Amos and the dissolved oxygen project at Claytor, which he described as new environmental costs. The forecasted in-service date for the dry sorbent injection project is December 2022. The forecasted in-service dates for the dissolved oxygen projects are November 2023 and November 2024.[136]

For the dry sorbent injection project, APCo proposes the recovery of AFUDC on CWIP from January 2022 through November 2022. For the dry sorbent injection and dissolved oxygen projects, APCo proposes recovery of a return on CWIP from December 2022 through the in-service date; depreciation and return on net assets placed in service; and property taxes.[137] To depreciate dry sorbent injection and dissolved oxygen investment, APCo proposes using the

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[129] Ex. 10 (Ross direct) at 9. December 2022 is the beginning of the proposed rate year in this case.
[130] *Id.* at 10.
[131] *Id.* at 16.
[132] *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015 ("2020 Triennial Review").
[133] Ex. 10 (Ross direct) at 10.
[134] *Id.* at 11.
[135] *Id.* Both amounts are Virginia retail jurisdictional. *Id.*
[136] *Id.* at 12.
[137] *Id.* at 12-13.

existing generation depreciation rates (4.63% and 3.64%, respectively), as approved for the applicable generation facilities in the 2020 Triennial Review.[138]

Mr. Ross does not currently expect any incremental O&M expenses associated with the CCR, ELG, dissolved oxygen, or dry sorbent injection investments he described.[139] He asserted that E-RAC capital investment, revenues, and expenses will be excluded from any other rider recovery and future APCo triennial earnings reviews through the use of unique projects and work orders to identify and track such costs.[140]

Mr. Castle sponsored the E-RAC tariff sheets that APCo proposed to become effective for service rendered on and after December 1, 2022.[141] He also sponsored bill impact calculations illustrating the customer impact of the proposed E-RAC.[142] As shown, the bill for a residential customer using 1,000 kWh per month would increase by $0.80, from $123.33 to $124.13.[143] Mr. Castle testified that the Company's pending fuel factor and triennial review proposals would increase such a customer's monthly bill by an additional $28 to $29.[144]

According to Mr. Castle, Commission denial of APCo's ELG investment in the instant proceeding would result in "sizable jurisdictional balances that must be recovered from Virginia customers who will not be receiving the capacity and energy benefits from the plants after 2028, absent an inter-jurisdictional agreement."[145] The impact of any such agreement on Virginia rates would depend on the agreement, as well as the timeframe for recovery of the Virginia jurisdictional share of plant balances.[146] If the Commission denied ELG recovery, Mr. Castle viewed the remaining net book value as a "stranded cost" even if Amos and Mountaineer continued to operate beyond 2028. He questioned whether APCo could compel West Virginia "to pick up that tab" based on a decision by the Commission.[147]

Mr. Castle confirmed that the proposed rate year in this proceeding is December 1, 2022, through November 30, 2023.[148] He summarized the costs included to develop APCo's proposed revenue requirement as of December 31, 2021, January 2022 through November 2022, and the rate year.[149] As shown, the Petition's proposed revenue requirement of approximately $33.6 million consists of: (1) an actual revenue component of $0.2 million; (2) a true-up revenue component of ($0.5) million; (3) a forecast AFUDC revenue component of $4.3 million; and (4) a forecast revenue component of $29.6 million. The proposed $33.6 million revenue

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[138] *Id.* at 16-17.
[139] *Id.* at 6, 9, 13. However, any such O&M expenses would be described in future E-RAC filings and would be included in APCo's monthly over-/under-recovery. *Id.*
[140] *Id.* at 18.
[141] Ex. 7 (Castle direct) at attached Sched. 1.
[142] *Id.* at attached Sched. 2.
[143] *Id.*
[144] Tr. at 55 (Castle).
[145] Ex. 7 (Castle direct) at 4.
[146] *Id.* While APCo does not currently have a methodology for segregating routine investments needed to operate the plants only until 2028 vs. those necessary for operations beyond 2028, Mr. Castle testified that the Company can develop such a methodology. Tr. at 51-52 (Castle).
[147] Tr. at 58-59 (Castle).
[148] Ex. 7 (Castle direct) at 4.
[149] *Id.* at 5.

requirement is $6.2 million higher than the $27.4 million going-level revenue requirement approved in the *2021 E-RAC Order*.[150]

According to Mr. Castle, the rate base for the forecasted revenue component includes Virginia jurisdictional rate base components projected through November 30, 2023, the end of the proposed rate year.[151] The proposed O&M expenses are an annual level of Virginia jurisdictional O&M compliance expenses, as discussed by APCo witness Ross. For RGGI expenses, APCo proposes to recover both an annual rate year level of such expenses and a one-year amortization of a deferred amount of such expenses projected through November 30, 2022.[152] APCo calculated the proposed revenue requirement using a 6.817% after-tax rate of return on rate base and a December 31, 2020 capital structure. The rate of return components, include the 9.20% return on equity authorized by the Commission in APCo's 2020 Triennial Review.[153]

The forecast AFUDC revenue component consists of the recovery of AFUDC associated with ELG and dry sorbent injection projects APCo calculated for the period July 2020 through November 2022, the month immediately preceding the proposed rate year. APCo proposed a one-year amortization of the AFUDC balance calculated by the Company.[154]

Mr. Castle testified that the Petition's proposed jurisdictional allocation of E-RAC costs is consistent with the allocation approved in the *2021 E-RAC Order*. Demand-related costs were allocated to the Virginia jurisdiction using a twelve coincident peak methodology for the year ended December 31, 2021, while energy-related costs were allocated based on actual energy usage for the year ended December 31, 2021. Mr. Castle proposed an energy allocation for RGGI expenses, based on projected CO_2 emissions at Clinch River.[155]

As for the allocation of Virginia jurisdictional costs to the Company's customer classes, Mr. Castle testified that this proposed allocation is also consistent with the *2021 E-RAC Order*, with the proposed energy and demand allocation factors updated using 2019 data. The demand allocation factors were developed using a six coincident peak methodology based on a growth-adjusted 2019 calendar year. The energy allocation factors were developed using growth-adjusted 2019 calendar year energy usage.[156]

For rate design, APCo proposed to use the billing determinants provided in the 2020 Triennial Review. The billing units exclude APCo's open access distribution ("OAD") tariff customers who solely pay distribution rates. The E-RAC would continue to apply to the Company's FRR-OAD tariff customers.[157] For billing purposes, APCo requested a rate effective

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[150] *Id.*
[151] *Id.* at 6-7.
[152] *Id.* at 7.
[153] *Id.* at 7-8. *See also* Ex. 4 (Petition) at Filing Sched. 46, Section 4, Capital Structure and Cost of Capital.
[154] Ex. 7 (Castle direct) at 8.
[155] *Id.* at 9. All of the rate base components, and certain compliance O&M expenses and depreciation expense that do not vary with the level of energy projection, were allocated based on demand. *Id.*
[156] *Id.* at 10.
[157] *Id. See also* Ex. 4 (Petition) at Filing Sched. 46, Section 5-Billing Determ.

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date for usage on December 1, 2022, or the first day of the month that is at least 15 calendar days following the date of any Order of the Commission.[158]

Mr. Castle asserted that the E-RAC rates should be incorporated into the balancing charge associated with the non-renewable generation rate adjustment clauses of APCo's Rider WWS. He believes Commission guidance confirming his opinion would benefit APCo[159] by providing clarity on the appropriate language in the tariff.[160] He testified that Commission guidance would not affect the amounts charged to Rider WWS participants or non-participants.[161]

Sierra Club

Sierra Club offered the testimony of **Shelley Kwok**, an Associate with Synapse Energy Economics, Inc. ("Synapse"). Ms. Kwok presented the results of an alternative modeling analysis, using her own EnCompass model. She described EnCompass as an industry standard capacity expansion and production cost model to develop an optimal replacement resource portfolio.[162] She compared the following four scenarios and one fuel price sensitivity:

> (1a) a scenario that includes ELG investments at Amos and Mountaineer and assumes APCo operates these facilities at an annual 69% capacity factor through 2040. The model was set up to add the same new resource portfolio as APCo's RPS Portfolio 1 ("WVPSC Preferred");
>
> (1b) a sensitivity to scenario (1a) that incorporates a coal price that is 2% to 12% higher than scenario (1a) ("WVPSC Preferred, high coal price sensitivity");
>
> (2) a scenario that includes ELG investments at Amos and Mountaineer and is set up the same way as scenario (1a), but assumes APCo operates Amos and Mountaineer economically through 2040 ("APCo Preferred");
>
> (3) a scenario that operates Amos and Mountaineer economically until December 31, 2028, then removes them from APCo's Virginia rate base. APCo then meets Virginia's system needs with a combination of solar PV, wind, battery storage, and market purchases based on what the model selected as optimal. After this first stage of modeling, this scenario was re-run with the full capacity of Amos and Mountaineer while locking in the same builds from the first stage to represent a future where West Virginia customers take 100% ownership of [Amos and Mountaineer] in 2029 and run them at a 69% capacity factor, while Virginia customers' energy and capacity needs are met with alternatives. ("Synapse Full Coal Removal"); and

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[158] Ex. 7 (Castle direct) at 11.
[159] *Id.*
[160] Tr. at 57 (Castle).
[161] Tr. at 56-57 (Castle).
[162] Ex. 23 (Kwok) at 2, 5, 11-12.

(4) a scenario that uses the same two-step process as scenario (3), except that it removes only Amos from APCo's Virginia rate base on December 31, 2028. This scenario also assumes Mountaineer operates at an annual 69% capacity factor through 2040 ("Synapse Partial Coal Removal").[163]

For each of the above scenarios, Ms. Kwok identified, by year, the amounts of each resource type that are added and the net amount of capacity purchased or sold.[164]

Ms. Kwok indicated that she set up her modeling using APCo's own input values, with one key exception for capacity market prices.[165] She pointed out that APCo's forecast includes prices of $100/MW-day to $151/MW-day for 2023 and 2024, which are three to four times higher than the actual auction clearing price of $34.14/MW-day she believes was relevant for PJM's 2023/2024 delivery year.[166] She further indicated that APCo's capacity forecast was prepared in July 2021, before significant changes to the PJM capacity market.[167] While she acknowledged there is a lot of uncertainty around future PJM capacity prices, she believes her alternative capacity price input values are a plausible future for prices and are more up-to-date and representative of current market conditions than APCo's forecast.[168] She testified that her capacity value inputs are a blend of a May 2022 S&P forecast and APCo's July 2021 forecast.[169] She illustrated her capacity input values, as well as the S&P forecast and APCo's forecast, using a figure included in Section I of the Analysis in this Report.[170]

For some of her modeling, as identified above, she modified generation assumptions to incorporate a 69% capacity factor for Amos and Mountaineer that she indicated is based on a WVPSC order.[171]

For the sensitivity Scenario (1b) above, Ms. Kwok asserted that APCo acknowledged it may not be able to secure the approximately 10 million tons of coal needed to operate at a 69% capacity factor at the current price.[172] Her high coal price sensitivity increase was calculated by increasing APCo's forecasted coal costs by the percentage difference between the reference case for EIA's 2020 Annual Energy Outlook (which APCo used for its forecast) and its low oil and gas supply case.[173] She assumed that if APCo needed to purchase more coal, the Company may have to go to more expensive sources to obtain it.[174]

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[163] *Id.* at 3-4, 12-15, 20.
[164] *Id.* at 29-31.
[165] *Id.* at 11-12. *See also id.* at 16 (identifying sources for key assumptions). As discussed below, Ms. Kwok also ran her model using APCo's higher forecasted capacity prices. *Id.* at 23.
[166] *Id.* at 17 and attached Ex. SK-4.
[167] *Id.* at 17-18 (referencing changes to PJM's minimum offer price rule, market seller offer cap, and effective load carrying capability). While Ms. Kwok was not aware of whether aspects of PJM's minimum offer price rule are currently on appeal, she believes APCo should study ratepayer impacts of the expanded minimum offer price rule is reinstated in some form by FERC. Tr. at 183-84 (Kwok).
[168] Ex. 23 (Kwok) at 18-19.
[169] Tr. at 173 (Kwok).
[170] Ex. 23 (Kwok) at 20.
[171] *Id.* at 3-4, 13 (citing Ex. 19.)
[172] Ex. 23 (Kwok) at 14, 21 and attached Ex. SK-2 (APCo response to Sierra Club No. 3-04).
[173] *Id.* at 20-21.
[174] Tr. at 185-86 (Kwok).

She asserted that her modeling demonstrates it is uneconomic, and not in the best interests of Virginia ratepayers, for APCo to invest in ELG compliance costs at Amos. Compared to the WVPSC Preferred Scenario, her results show a $202 million net present value ("NPV") savings from removing Amos from Virginia rate base beginning in 2029, while operating Mountaineer at a 69% capacity factor, and a $12 million NPV cost from removing both Amos and Mountaineer.[175] She summarized the results of her modeling with the following table, showing the NPV results and the resource mix for each of the four scenarios she modeled.[176]

Table 1. Summary of Synapse Modeling Results in 2040, Virginia Jurisdiction

	WV PSC Preferred	APCo Preferred	Full Coal Removal from Rate Base	Partial Coal Removal from Rate Base
NPVRR* (2022-2040, $ Millions)	$5,915	$5,743	$5,927	$5,713
Solar (MW)	2,929	2,929	3,507	3,507
Wind (MW)	855	855	524	524
Battery Storage (MW)	625	625	476	476
Gas (MW)	512	512	512	512
Coal (MW)	2,295	2,295	167	823
Net capacity exchange (MW)	-1,369	-1,639	310	-285

* *Note: NPVRR numbers do not account for the additional costs caused by REC deficits observed in Scenarios 1 and 2.*

As shown above, the Synapse Partial Coal Removal Scenario has the lowest NPV revenue requirement, followed by the APCo Preferred Scenario. Ms. Kwok believes the Commission should use the WVPSC Preferred Scenario, rather than the APCo Preferred Scenario, as the baseline for comparison to the other two scenarios since she views the 69% capacity factor as a mandate of the WVPSC by which APCo must abide.[177] Ms. Kwok acknowledged that these results – without consideration of other factors, discussed below – indicate that leaving Mountaineer in service is $214 million more economic than removing both Amos and Mountaineer.[178]

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[175] Ex. 23 (Kwok) at 6, 22.

[176] *Id.* at 7. The negative figures in the net capacity exchange row represent exports, while the positive figure represents import. *Id.*

[177] Tr. at 158-59 (Kwok).

[178] Tr. at 189 (Kwok) (discussing, in the context of another table, the difference between the $5.927 billion and $5.713 billion amounts that are also shown in Table 1 above).

Ms. Kwok conducted further analysis that incorporated APCo's higher forecasted capacity price. She summarized the results of this analysis using the following table.[179]

Table 5. NPVRR Results for Scenarios Using APCo's Capacity Price

Scenario	Revenue Requirement for APCo's Virginia Ratepayers, using a higher capacity price forecast		
	NPVRR* ($Millions)	Delta from West Virginia PSC Preferred ($Millions)	Delta from APCo Preferred ($Millions)
1a. West Virginia PSC Preferred	$5,757	N/A	$173
1b. West Virginia PSC Preferred, high coal price	$5,931	$174	$346
2. APCo Preferred	$5,585	-$173	N / A
3. Full Coal Removal	$6,030	$273	$455
4. Partial Coal Removal	$5,720	-$38	$135

** Note: NPVRR numbers do not account for the additional costs caused by REC deficits observed in Scenarios 1 and 2.*

As shown above, her APCo Preferred Scenario has the lowest NPV revenue requirement, followed by her Partial Coal Removal Scenario. Although these results show removing both Amos and Mountaineer did not result in net savings, she stressed that this modeling assumed an unrealistically high capacity price forecast and conservative assumptions, including no future carbon pricing on coal generation during the next eighteen years.[180] She also indicated there are risks associated with higher fuel prices, some of which she quantified in her Scenario (1b).[181]

Ms. Kwok indicated that cost savings of her Full and Partial Coal Removal Scenarios are likely conservative because her modeling results do not include the costs associated with a REC shortfall that APCo projects under Scenarios (1) and (2). She calculated the costs associated with such REC shortfalls using a $45/MWh compliance penalty, which she recognized is the upper bound of the potential risk of RPS non-compliance.[182] Adding the non-compliance penalty, as described above, increased her results for Scenarios (1) and (2) (but not 3 or 4) by $153 million.[183] Ms. Kwok testified that the $153 million amount includes $35 million she attributed to an error in APCo's modeling of APCo's Buck and Byllesby hydroelectric plants.[184]

[179] Ex. 23 (Kwok) at 23.
[180] *Id.* at 23-24.
[181] Tr. at 159, 201-02 (Kwok).
[182] Ex. 23 (Kwok) at 26-27.
[183] *Id.* at 26.
[184] *Id.*; Tr. at 203 (Kwok).

Ms. Kwok testified that if the Commission does not approve ELG costs, Virginia ratepayers will avoid paying for the ELG investment as well as future capital expenditures, fixed operation and maintenance costs, and taxes required to maintain Amos and Mountaineer beyond 2028. She provided a table of annual avoidable fixed costs based on a document APCo provided in discovery, with such combined amounts (*i.e.*, for both plants) ranging from annual costs of approximately $12 million to $95 million.[185]

In addition, Ms. Kwok provided figures illustrating the amount of energy each resource type of APCo's would produce through 2040 under each of her scenarios. These figures also illustrate the periods when her results show APCo would be a net importer or exporter of energy.[186] Ms. Kwok does not view relying on the PJM energy market as a negative strategy, because this market is well-established, liquid, and competitive. She also believes passage of the Inflation Reduction Act[187] might decrease market prices in the future as more zero-variable cost resources are built in PJM.[188] She also believes that information APCo filed in its 2022 integrated resource plan ("IRP") indicating that a hybrid plan would rely on net energy imports for up to 56% of load requirements in certain years suggests that APCo has found it acceptable to rely on the market to a certain extent.[189]

Ms. Kwok asserted that it is reasonable for APCo to rely on the PJM market for energy and capacity needs. She indicated that the "Rest of RTO" zone in which APCo is located generally is the lowest-priced.[190] She further indicated, among other things, that reliance on the capacity market in her coal removal scenarios steadily declines over time as renewable and storage resources are built.[191] Her Full Coal Removal Scenario shows a capacity market purchase of 1,416 MW in 2029 (when removal occurs) that gradually decreases to a purchase amount of 310 MW by 2040.[192] Her Partial Coal Removal Scenario shows a capacity market purchase of 821 MW in 2029 that gradually decreases until 2038, when APCo would have capacity to sell.[193] She testified that, assuming APCo remains an FRR entity, depending on bilateral capacity markets for changing amounts of capacity to replace Amos and/or Mountaineer would subject APCo to variances in the short-term market.[194]

Ms. Kwok recognized that APCo cannot currently purchase capacity from PJM's market because APCo is an FRR entity. However, she testified that FRR status is a choice made by APCo, which has a responsibility to closely analyze whether its ratepayers would benefit from such participation, especially given how low auction prices have fallen in recent years.[195] Ms. Kwok confirmed that PJM's rules allow APCo to terminate its FRR election.[196] Ms. Kwok

[185] Ex. 23 (Kwok) at 28 (citation to workpaper as source omitted).
[186] *Id.* at 32-34.
[187] Inflation Reduction Act of 2022, Public Law 117-169 (2022).
[188] Tr. at 165 (Kwok).
[189] Tr. at 165-68; Ex. 24.
[190] Ex. 23 (Kwok) at 34-35.
[191] *Id.* at 35.
[192] *Id.* at 30.
[193] *Id.* at 31.
[194] Tr. at 190-92 (Kwok).
[195] Tr. at 168-69 (Kwok) (indicating clearing prices in the past few years have been in the $30 to $50 per MW-day range).
[196] Tr. at 168, 179-81 (Kwok); Exs. 25, 26.

indicated that in discovery APCo identified high-level benefits of the FRR vs. PJM's capacity auctions, but did not quantify any of the costs or benefits of either option. She believes such an analysis is particularly important right now, given recent changes to PJM's rules that have driven auction prices down.[197] Ms. Kwok acknowledged that there are some benefits from FRR status, including a lower reserve requirement that produces cost savings of some significance and a broader ability to avoid or mitigate non-performance charges.[198]

According to Ms. Kwok, a recent report by PJM's market monitor indicated approximately 12,000 MW of capacity that was offered in the capacity auction for 2023/2024 did not clear. This indicates to her that there is surplus capacity available to be purchased. Additionally, she indicated that a $34 per MW-day clearing price suggests that surplus capacity could be purchased competitively.[199]

Ms. Kwok testified that the passage of the Inflation Reduction Act could result in less reliance on the market than shown in her analysis, especially if the law results in APCo procuring more of its own renewables and storage.[200]

Ms. Kwok believes her analysis shows that (1) removing Amos from the Virginia rate base in 2028 is the least-cost scenario and is in the best interests of Virginia ratepayers because it saves more than $202 million (compared to the WVPSC Preferred Scenario) between 2022 and 2040, and (2) the benefits of removing Amos and Mountaineer from the Virginia rate base increase substantially after accounting for the impact of recent PJM policies lowering capacity market prices, the risk of REC deficiencies and VCEA non-compliance, as well as future carbon policies that could make coal generation even less economic.[201]

In Ms. Kwok's opinion, APCo's analysis is oversimplified and does not sufficiently support the Petition. She expressed concern that APCo's spreadsheet analysis overstates the amount of capacity the Company would need to acquire to replace Amos and Mountaineer because the Company did not account for the firm capacity contributions from the rest of the generating units in its resource portfolio, both existing and planned. In her view, APCo would only need to replace the amount of firm capacity required to satisfy its reserve margin.[202] While her analysis assumes a 14.9% reserve margin, she identified years when APCo's analysis shows a higher margin. She emphasized APCo's 39.8% projected reserve margin in 2039, which suggests to her that ratepayers "are paying twice as much as what they need."[203] She also believes APCo overstated the amount of replacement capacity by 386 MW because it used the nameplate capacity, rather than firm capacity.[204] She indicated that APCo's analysis also did not

[197] Tr. at 169-70 (Kwok).
[198] Tr. at 196-97 (Kwok), 202-03 (Kwok).
[199] Tr. at 170 (Kwok).
[200] Tr. at 171 (Kwok).
[201] Ex. 23 (Kwok) at 35.
[202] She reproduced a table from APCo's RPS Plan showing APCo's projected reserve margin in 2029 exceeds its 14.9% reserve requirement, indicating to her that APCo will have a capacity surplus in a future where both Amos and Mountaineer remain in service. *Id.* at 11 (showing projected reserve margins exceeding 14.9% from 2025 through 2039).
[203] Tr. at 175-76, 199 (Kwok); Ex. 23 (Kwok) at 11.
[204] Ex. 23 (Kwok) at 9-10.

optimize the timing of replacement capacity in Case 1 or 2 to account for the falling price of renewables over time, nor did it include a scenario that allowed a combination of renewable resources and firm capacity purchases to replace the coal capacity.[205] While she described setting up a model for a Virginia-specific optimized analysis as a tricky exercise, Ms. Kwok indicated that she was able to do it. She believes APCo's reliance on the results from a prior analysis creates a bias in its analysis in the instant case towards the continued operation of Amos and Mountaineer.[206]

Ms. Kwok pointed out that APCo's analysis did not consider the impact that uneconomic coal generation could have on energy costs or revenues. She called this "a large oversight," given the WVPSC order that she believes required APCo to run Amos and Mountaineer at a 69% capacity factor.[207] Ms. Kwok provided data and illustrations showing that from 2017 to 2021 the Amos units have operated at annual capacity factors between 31% to 57% and Mountaineer has operated at annual capacity factors between 49% to 71%.[208] Ms. Kwok testified that if both of these plants are mandated to run at a 69% capacity factor, APCo will lose money whenever costs per MWh are higher than revenues earned in the energy market, and ratepayers will be forced to bear the unnecessary associated costs. She recommended the Commission fully consider this risk to Virginia ratepayers when evaluating whether Virginia should approve the proposed ELG costs.[209] Ms. Kwok also provided data and visualizations showing APCo's projected annual capacity factors through 2040 for Amos and Mountaineer.[210]

Ms. Kwok added that it would be very complicated for the Commission to calculate the cost of uneconomic dispatch, if the WVPSC mandates a 69% capacity factor for Amos and Mountaineer. She explained that this sort of calculation would require a counterfactual case for comparison and would involve O&M, fuel costs, and potentially capital costs.[211] Ms. Kwok recognized that operating Amos and Mountaineer at a capacity factor of at least 69% would require them to run at times when they are economic and times when they are not.[212]

Ms. Kwok also cited industry reports identifying amounts of recent and scheduled coal retirements and indicating that coal-fired generation will become less economic in the future because of both economic and regulatory forces.[213] She explained that decreasing renewable costs have contributed to coal-plant retirements and RPS policies in neighboring PJM states will continue to increase the volume of renewables. She believes this will cause the locational marginal prices for energy to decline, further lowering energy revenues earned by coal units.[214]

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[205] *Id.* at 10.
[206] Tr. at 175 (Kwok).
[207] Ex. 23 (Kwok) at 10.
[208] *Id.* at 36-37.
[209] *Id.* at 38.
[210] Ex. 27C.
[211] Tr. at 154-57 (Kwok).
[212] Tr. at 161 (Kwok).
[213] Ex. 23 (Kwok) at 38-40.
[214] *Id.* at 39-40.

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Based on her analysis, Ms. Kwok recommended that the Commission deny Virginia's share of the costs associated with ELG compliance at Amos and Mountaineer.[215] She is not asking the Commission to adopt a particular resource portfolio; rather, she believes her modeling suggests that there are many options for the replacement of Amos and possibly also Mountaineer.[216] While Ms. Kwok did not re-run her model to incorporate the Inflation Reduction Act, she expects that such a re-run would show that the relative benefit of the coal removal scenarios would increase because this legislation has significantly reduced the costs of wind, solar, and storage.[217] Ms. Kwok believes the extended Inflation Reduction Act tax credits will have more of an impact than the present day inflation, which she views as more of a temporary issue that she hopes will be resolved in the future.[218] She testified that the legislation extended production tax credits and/or 30% investment tax credits for wind, solar, and storage through 2032, followed by a four-year phaseout or, if certain emission reduction goals are not met by 2032, a full extension.[219]

Ms. Kwok recognized that her analysis did not incorporate the updated ELG cost estimates that APCo witness Sherrick provided during the hearing. She acknowledged that lower ELG costs would have a favorable impact on these investments.[220]

Coal Association

The Coal Association offered the testimony of **Emily S. Medine**, a Principal of Energy Venture Analysis, Inc. Ms. Medine supported APCo's position on ELG costs and provided additional reasons which she believes support ELG investment.

She discussed the generation resource portfolios developed by APCo for its RPS Plan, which was attached to APCo witness Martin's testimony. She discussed the following table in APCo's RPS Plan showing new resources APCo considered and limitations thereto.[221]

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[215] *Id.* at 8, 42.
[216] Tr. at 177 (Kwok).
[217] Tr. at 153, 159 (Kwok).
[218] Tr. at 194 (Kwok).
[219] Tr. at 200-201 (Kwok). Ms. Kwok believes storage is only eligible for the investment tax credit. Tr. at 200 (Kwok). She also testified that developers or utilities can obtain additional tax credit benefits depending on, for example, where a resource is constructed and the source of materials. Tr. at 201 (Kwok).
[220] Tr. at 186-87 (Kwok).
[221] Ex. 1 (Medine) at 6.

TABLE 12: NEW RESOURCE LIMITATIONS

New Resource Assumptions							
Resource Type	First Year Available	Life	Portfolio 1,2,6	Portfolio 3 &4	Portfolio 5	Individual Technology Total	Cumulative Technology Total
Solar PPA	1/1/2025	35 years	150 MW/yr	300 MW/yr	150 MW/yr	900 MW	3,150 MW
Solar Utility T1		35 years	300 MW/yr	600 MW/yr	300 MW/yr	2,100 MW	
Solar Utility T2		35 years	150 MW/yr	300 MW/yr	150 MW/yr		
Solar Hybrid		35 years	150 MW Block 450 MW/yr			1,050 MW	
Wind PPA Limits	1/1/2026	30 years	100 MW/yr	300 MW/yr	100 MW/yr	350 MW Total	950 MW
Wind Owned Limits	1/1/2026	30 years	200 MW/yr	600 MW/yr	-	600 MW Total	
Wind Owned Limits	1/1/2026	30 years	-	-	2026 1,200 MW 2028 2,600 MW 2030 3,600 MW 2032 4,600 MW 2035 5,000 MW	5,000 MW Total	5,350 MW
Renewable Energy Certificates	1/1/2025	5 years	20 Blocks/yr			~7,000 GWh	~7,000 GWh
Stand Alone Storage	1/1/2025	10 years	2,500 MW/yr			12,500 MW	12,500 MW
NG 240 MW Combustion Turbine	1/1/2026	30 years	P1 unlimited P2 N/A	P3 unlimited P4 N/A	N/A	Unlimited	Unlimited
NG 1,100 MW Combined Cycle	1/1/2026	30 years	P1 unlimited P2 N/A	P3 unlimited P4 N/A	N/A	Unlimited	Unlimited

Ms. Medine indicated that APCo also recognized there are new technologies not included in its modeling, such as carbon capture and storage, hydrogen-capable combustion turbines, long-duration storage, and small modular nuclear reactors. She believes continuing to operate Amos and Mountaineer beyond 2028 will provide for greater clarity as to which technologies should be pursued.[222] She pointed out that small modular reactors are expected to be placed in service by the end of this decade and, if all goes according to plan, commercial penetration will increase in the 2030s.[223]

Ms. Medine took issue with APCo's inclusion of combined cycle gas turbines in RPS Plan Cases 1 and 3. First, she found it problematic because this resource, absent a carbon capture retrofit or conversion to green hydrogen, is inconsistent with AEP's decarbonization strategy to achieve net-zero emissions by 2050. Second, she believes a shorter analytical period is warranted to account for AEP's 2050 target date.[224]

For purposes of the instant proceeding, Ms. Medine found it best to focus on APCo's RPS Plan NPV results only through 2039.[225]

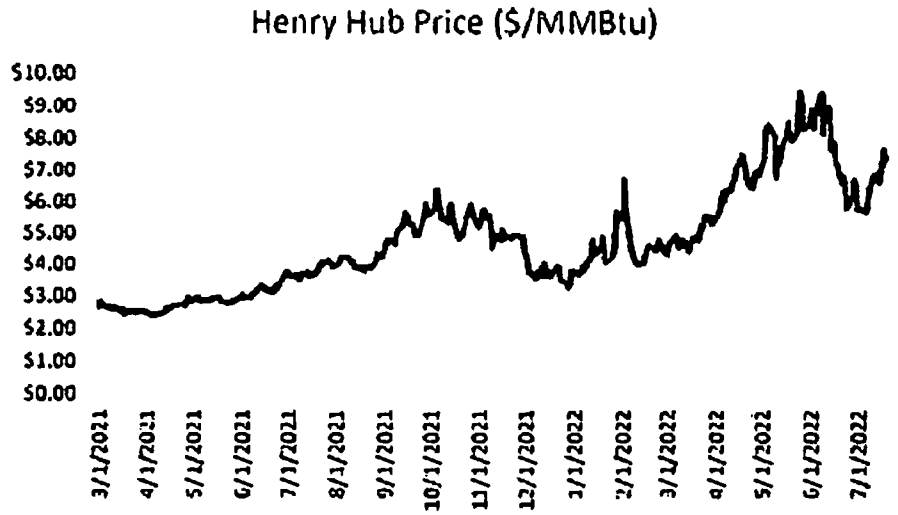
Ms. Medine discussed three WVPSC orders that culminated in the WVPSC confirming that "West Virginia would pay for the entire ELG expenses at the plants and that after 2028 the

[222] *Id.* at 6-7. She noted that Mountaineer has been deemed an attractive site for carbon capture and that an increase to the tax credit for carbon capture sequestration was included in the Inflation Reduction Act of 2022. *Id.* at 6.
[223] *Id.* at 20. She noted that small modular reactors could also be a key to producing green hydrogen through electrolysis, which will determine the viability of hydrogen conversions of gas plants. *Id.*
[224] *Id.* at 7-8. *See also* Ex. 2 (discovery responses of the Association addressing, among other things, possible zero emission strategies).
[225] Ex. 1 (Medine) at 9. She indicated that APCo did not include potential transmission costs in this analysis. *Id.*

capacity and energy produced by these plants would be for the benefit of West Virginia ratepayers only."[226] According to Ms. Medine, the WVPSC found that if the total cost of ELG compliance was added to APCo's West Virginia rate base, it would be materially less than the cost of replacement capacity for APCo's West Virginia jurisdictional customers.[227] She believes this finding is consistent with APCo's position in the instant proceeding.[228]

Ms. Medine considers it unlikely that there would be a dispute or "complications between West Virginia and Virginia related to the continued operations of Amos and Mountaineer," given APCo's acknowledgement that post-2028 Virginia jurisdictional customers have no rights to the capacity and energy (absent Virginia ELG funding) and net book value at that time remains with Virginia customers.[229]

As for the additional reasons Ms. Medine believes support ELG funding, she identified the combination of faster-than-expected demand recovery from COVID, natural gas pricing and availability, supply chain disruptions, and the war in Ukraine. She illustrated recent increases in natural gas price levels and volatility with the following chart.[230]



She cited various factors contributing to this increase, including low capital investment in 2019 and 2020 due to low prices followed by an increase in demand that has caused the natural gas industry to "play catchup." She also cited, among other things, the difficulty in finalizing greenfield pipelines needed to deliver natural gas from supply areas to demand centers.[231]

Ms. Medine indicated that coal had similar problems because the industry was slow to reactivate production levels to meet increasing demand. However, she does not have the same concerns about long-term coal pricing as she does with natural gas pricing because she believes

[226] *Id.* at 10-11.
[227] *Id.* at 11.
[228] *Id.* at 12.
[229] *Id.*
[230] *Id.* at 13 (citation to EIA website as source omitted).
[231] *Id.* at 14.

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coal's current problems are short-term supply issues that can and will be resolved in short order. Additionally, the ability to export coal is limited due to constraints on East Coast terminals, unlike liquified natural gas ("LNG") capacity.[232] She provided a list of recent LNG projects currently under construction, approved by FERC, under review by FERC, and in a FERC pre-filing process.[233] She discussed the current economic and political incentives for exporting natural gas.[234]

Ms. Medine testified that as coal plant retirements increase, the ability of coal-fired plants to operate as a competitive cap to natural gas prices is eliminated. She indicated that natural gas prices have increased rapidly in many regions where coal supply was inadequate at coal-fired power plants and overall coal-fired capacity was reduced due to retirements. She believes that increased reliance on natural gas for generation will increase ratepayer risks by exposing utilities to price swings and decreasing the influence of other sources of generation on natural gas prices. That is, unless another type of dispatchable generation, such as small modular nuclear reactors or significant battery penetration, is used to replace significant coal plant retirements.[235]

Ms. Medine provided several recent examples of resource decisions (retirements, conversions, and new construction) being deferred due to supply chain disruptions.[236]

Ms. Medine believes the Commission should consider ELG approval as a hedge against market volatility, insurance against supply chain issues, and an opportunity to gain clarity on which resources should be pursued.[237]

Staff

Staff presented the results of its investigation through the testimonies of **Oliver C. Collier**, Assistant Utilities Analyst in the Commission's Division of Public Utility Regulation ("PUR"); **Timothy A. Morris**, Utilities Analyst in PUR; **Justin Morgan**, Manager in the Commission's Division of Utility Accounting and Finance ("UAF"); and **Cameron T. Hunt**, Utility Specialist in UAF.

Mr. Collier provided an overview of the components of the proposed E-RAC revenue requirement, cost allocation, and rate design, as discussed by APCo witness Castle.[238] Staff did not oppose the proposed cost allocation or rate design, and recommended that any Commission-approved rates be consistent with the proposed allocation and rate design methodologies.[239]

Mr. Morris explained the Company's economic analysis provided with its Petition. He described the three replacement scenarios, assumptions associated with the types and amount

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[232] *Id.* at 14-15.
[233] *Id.* at 18.
[234] *Id.* at 17-18.
[235] *Id.* at 14-15.
[236] *Id.* at 16-17.
[237] *Id.* at 19.
[238] Ex. 28 (Collier) at 5-8.
[239] *Id.* at 8.

(1,907 MW) of replacement capacity.[240] He noted that while APCo's RPS Portfolios present the Company's potential generation fleet for the entire system, APCo adjusted such results in this proceeding to reflect only the portion of each total RPS Portfolio needed to replace the Virginia jurisdictional share of Amos and Mountaineer's UCAP rating (1,907 MW).[241]

Mr. Morris recognized that APCo's initial analysis did not include expected energy margins of Amos and Mountaineer.[242] He testified that, all else being equal, a positive energy margin would reduce the cost of service associated with the continued operation of Amos and Mountaineer, resulting in lower costs for Virginia jurisdictional customers, while a negative energy margin would increase the cost of service.[243]

Staff witness Morris also recognized that APCo's analysis assumes the continuation of its existing depreciation rates, although APCo intends to propose changes to its Virginia jurisdictional depreciation rates for Amos and Mountaineer in a future proceeding.[244] He testified that changes in Amos and Mountaineer's depreciation rates can affect the amount or timing of cost recovery under scenarios where the ELG project costs are not approved and therefore changes in depreciation rates may affect the NPV cost of potential replacement scenarios in the instant proceeding.[245]

Mr. Morris explained that APCo's analysis assumed the full nameplate capacity of Amos and Mountaineer (2,100 MW) would need to be replaced in Case 3. However, Staff believes using Amos and Mountaineer's UCAP rating, rather than its nameplate rating, more accurately represents APCo's replacement capacity need.[246]

Mr. Morris also viewed some of the inputs in the PLEXOS modeling from the 2021 RPS Plan as stale. He explained that after such inputs were developed in July 2021, ELCC values have been updated and many variable conditions such as fuel costs and commodity and market prices have changed.[247]

As shown in Section I of this Report's Analysis, Mr. Morris presented APCo's NPV results, as filed and with two modifications.[248] The first modification incorporates an updated analysis provided by APCo in response to Staff discovery that includes its projected energy margins for Amos and Mountaineer.[249] The second modification was that for Case 3, Staff

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[240] Ex. 30 (Morris) at 6-9.
[241] *Id.* at 8.
[242] Tr. at 215 (Morris).
[243] Ex. 30 (Morris) at 10.
[244] *Id.* at 10-11.
[245] *Id.* at 11; Tr. at 217 (Morris).
[246] Ex. 30 (Morris) at 11-12.
[247] *Id.* at 11.
[248] *Id.* at 10, 12.
[249] Tr. at 215-16 (Morris); Ex. 30 (Morris) at 12-13. APCo projects that Mountaineer will operate at a profit for all years between 2028 and 2040. Amos units are projected to operate at a loss during some of these years, but is expected to produce a positive net energy margin overall. Ex. 30 (Morris) at 13.

adjusted APCo's results to reflect Amos and Mountaineer's UCAP, not nameplate, ratings.[250]

In discovery, APCo indicated that Virginia customers could avoid needing to pay for some alternative sources of capacity and may continue to benefit from the energy produced by Amos and/or Mountaineer. This could be the case under an approved potential intracompany financial arrangement by which Virginia customers compensate West Virginia customers to receive the capacity benefits of Amos and/or Mountaineer. Mr. Morris testified that such a result could lower the NPV cost of the replacement scenarios presented in APCo's analysis.[251]

According to Mr. Morris, a potential utility resource investment is typically evaluated on a total system basis – meaning the utility would attempt to determine the projected NPV change in its total system generation portfolio that results from the inclusion, or exclusion of the resource under consideration.[252] Mr. Morris testified that APCo provided such an analysis in its 2021 RPS Plan filing, the results of which Mr. Morris summarized in a the table provided below in Section I of this Report's Analysis.[253] As shown by Mr. Morris, the analysis from APCo's RPS Plan filing indicated that the continued operation of Amos and Mountaineer produced a NPV benefit of $1.242 billion and $2.535 billion, respectively, over alternative replacement scenarios.[254]

Mr. Morris also discussed the results that Sierra Club witness Kwok presented from her modeling. While Staff has not independently verified the results of her analysis or underlying assumptions, Staff believes there could be value in analysis that reflects alternative future scenarios under different assumptions as sensitivities.[255] The results of Ms. Kwok's analysis suggest to Staff that the continued operation of Amos and Mountaineer, inclusive of the ELG project costs, reflects a lower cost resource alternative compared to her "Full Coal Removal" option. Her "Partial Coal Removal" option would be the lowest-cost option among all of the scenarios she considered, regardless of whether the units operate economically or at a 69% capacity factor.[256]

Based on the economic analyses presented in this proceeding, Staff concluded that it appears the continued operation of Mountaineer, inclusive of ELG project costs, is a lower cost resource option than the range of replacement alternatives presented in this case. However, the economic viability of Amos is unclear to Staff. Mr. Morris indicated that the extent to which Amos produces a net benefit appears to be largely dependent on whether this facility will be dispatched economically, or at a designated 69% capacity factor, and on the accuracy of the assumptions and inputs contained within APCo's supporting analysis.[257] Mr. Morris also

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[250] Ex. 30 (Morris) at 11-12. While Staff also requested that APCo update its analysis to incorporate the Company's anticipated change in Amos and Mountaineer's depreciation rates, APCo indicated it could not incorporate such changes because the Company has not yet determined the depreciation rates it will propose in a future proceeding. *Id.* at 12.
[251] *Id.* at 14.
[252] *Id.* at 14-15.
[253] *Id.* at 15.
[254] *Id.*
[255] *Id.* at 16-17.
[256] *Id.* at 17-18.
[257] *Id.* at 18.

indicated that APCo was directed to provide a comprehensive retirement analysis of Amos and Mountaineer in its 2022 IRP filing, which is currently pending before the Commission.[258] Staff believes the Commission may receive more clarity on the economic viability of Amos ELG project costs once the WVPSC has rendered its final determination in its expanded net energy cost ("ENEC") proceeding and upon the conclusion of the 2022 IRP.[259] Staff did not take a position on the reasonableness of the continued operation of Amos, inclusive of associated ELG project costs.[260]

Mr. Morgan summarized APCo's proposed Rider E-RAC revenue requirement with the following table.[261]

Summary of Company's Proposed Revenue Requirement (In Thousands)

Line No.	Description		Amount
	New Proposals		
1	ELG	$	18,444
2	DSI	$	621
3	DO	$	220
4	RGGI	$	820
5	Subtotal: Revenue Requirement for New Proposals	$	20,105
	Previously Approved		
6	CCR Related Carrying Charges, AFUDC, & Depreciation	$	4,548
7	CCR Related Compliance O&M	$	40,519
8	Total Costs	$	65,172
9	Less: Recoveries	$	(31,566)
10	**Total Revenue Requirement**	**$**	**33,606**

Staff audited support for APCo's actual construction costs and determined that such costs appear to be appropriately recoverable through Code § 56-585.1 A 5 e. Staff also reviewed APCo's projections and does not take issue with such projections at this time. Staff will continue to review actual costs of the E-RAC as they are incurred and any difference between projections and actual costs will be handled through a future E-RAC true-up.[262] Mr. Morgan

[258] *Id.* at 18-19.
[259] *Id.* at 19.
[260] *Id.*
[261] Ex. 31 (Morgan) at 3.
[262] *Id.* at 4.

also testified that Staff will conduct a more detailed review of the projected RGGI costs as part of the true-up process.[263] He testified that in his review of the RGGI revenue requirement calculation in this case, he was not aware that some of the hours of operations were the result of uneconomic dispatch because APCo had chosen must-run status.[264]

Mr. Morgan explained that to depreciate the capital investments proposed for Rider E-RAC, APCo used the estimated useful lives that formed the basis for the depreciation rates approved by the Commission in the 2020 Triennial Review, which he summarized as follows.[265]

Summary of Proposed Retirement Dates and Depreciation Rates		
	End of Useful Life	APCo VA Depreciation Rate
Amos		
CCR	2033	9.52%
ELG	2033	9.52%
DSI	2032	4.63%
Mountaineer		
CCR	2040	5.71%
ELG	2040	5.71%
Claytor Lake		
Dissolved Oxygen	2040	3.64%

Mr. Morgan did not take issue with APCo's proposed depreciation rates at this time. However, Staff recommended the Commission direct APCo to incorporate a depreciation rate analysis of its E-RAC investment in its next depreciation study, including net salvage considerations and any excess/deficient depreciation accruals on such assets through the date of the study.[266]

Mr. Morgan presented Staff's Rider E-RAC revenue requirement calculations.[267] Staff calculated the same revenue requirement amount as proposed by APCo.[268] Mr. Morgan also presented APCo and Staff's estimated $439.19 million lifetime revenue requirement of the E-RAC.[269]

Mr. Morgan provided APCo's responses to Staff interrogatories about environmental justice considerations. These responses indicate, among other things, that the projects at issue in the Petition are located in West Virginia and that they will allow the subject power plants to comply with more stringent environmental regulations.[270]

Mr. Morgan testified that retail ratepayers essentially pay for the utility costs plus whatever is left on the PJM bill. While APCo makes money on off-system sales, for APCo's

[263] Tr. at 225 (Morgan).
[264] Tr. at 226 (Morgan).
[265] Ex. 31 (Morgan) at 4-5.
[266] Mr. Morgan indicated APCo's next study should be based on depreciable plant balances as of a date no later than December 31, 2024. *Id.* at 5, n.3.
[267] *Id.* at attached Scheds. 1a-9.
[268] *Id.* at 6.
[269] *Id.* at 6-7.
[270] *Id.* at 8.

generation that clears the PJM energy market and matches APCo's load, there is no margin because, as a vertically integrated utility, PJM bills APCo at the same price at which the generation clears.[271]

Mr. Hunt addressed APCo's proposed capital structure and cost of capital for Rider E-RAC. APCo proposes using the December 31, 2020 capital structure and a 6.817% weighted average cost of capital, both of which Staff verified.[272]

APCo - Rebuttal

APCo offered the rebuttal testimony of **Messrs. Beam, Martin, and Ross.**

Mr. Beam commented on APCo's efforts to obtain clarification of some of the WVPSC orders discussed by Sierra Club and Staff witnesses. He testified that in the Company's current ENEC proceeding before the WVPSC, APCo has asked for clarification of the 69% capacity factor identified by the WVPSC, as well as confirmation that the costs of uneconomic dispatch of Amos and Mountaineer would be borne only by West Virginia customers.[273] He attached to his testimony in the instant E-RAC case testimony filed by the Company in the pending ENEC proceeding.[274] He does not believe APCo is under a mandate[275] and testified that the Company is not currently running Amos and Mountaineer to achieve a 69% capacity factor.[276] Mr. Beam also cited provisions of Code § 56-249.6 that he understands, by advice of counsel, empower the Commission to disallow fuel costs if the Commission makes certain findings.[277] He testified further that APCo would not seek recovery in Virginia of uneconomic costs incurred as a result of any requirement by the WVPSC to run generation facilities in an uneconomic manner.[278]

Citing market volatilities and the challenges of building a reasonably priced portfolio of renewable resources by 2028, Mr. Beam described Amos and Mountaineer as "a very necessary insurance policy in these tumultuous times, a policy with a very low premium."[279] He testified that these plants allow APCo to meet the majority of its capacity obligations in PJM, and have provided reliable, low-cost energy to APCo's Virginia customers for decades.[280] According to Mr. Beam, the challenges and complications related to securing replacement capacity and energy would not be more manageable if only the ELG investment for Amos were denied by the Commission because APCo's exposure to the volatile energy market and the need to find replacement capacity would only be reduced, not eliminated.[281]

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[271] Tr. at 301-05 (Morgan).
[272] Ex. 29 (Hunt) at 2 and attached Sched. 1.
[273] Ex. 33 (Beam rebuttal) at 2.
[274] *Id.* at attached Rebuttal Sched. 1.
[275] Tr. at 244 (Beam).
[276] Tr. at 253-54 (Beam).
[277] Ex. 33 (Beam rebuttal) at 3; Tr. at 255 (Beam).
[278] Tr. at 268 (Beam).
[279] Ex. 33 (Beam rebuttal) at 1.
[280] *Id.* at 1-2.
[281] *Id.* at 2.

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Based on a communication with an AEP employee involved in scheduling, it is Mr. Beam's understanding that Clinch River "uneconomically schedule[s] itself" usually to comply with air permits. He explained that there are set times when units must be tested that are tied to their air permits. Because a third party does this type of testing, it is hard to line up this testing with the market. If Clinch River doesn't do environmental testing, it loses its air permit.[282] He indicated that the only other reason Clinch River has voluntarily self-scheduled is for non-environmental testing.[283] Mr. Beam indicated that he thinks, going forward, APCo could commit to documenting and providing in its initial case-in-chief all of the hours it self-schedules and the associated reasons.[284]

Mr. Beam acknowledged that the current coal market is different from the past due to some coal production issues. However, based on his experience, he testified that usually when you go out for larger quantities of coal, a better price per unit can be obtained.[285]

In response to Sierra Club witness Kwok's testimony that renewable prices have decreased and will continue to decrease due in part to the Inflation Reduction Act, Mr. Beam testified that bid prices received by APCo in its annual RFPs for renewable prices have increased.[286]

Mr. Martin asserted that Sierra Club witness Kwok's economic analysis does not support her conclusion that ELG investments should be denied at Amos or Mountaineer.[287] He testified that:

> [Ms. Kwok's] scenario in which the Virginia jurisdictional share of both [Amos and Mountaineer] are removed and replaced in 2028 is projected to result in higher costs than a case in which they dispatch economically and serve customers through 2040. She also prepared a scenario in which only Amos is removed in 2028, and that scenario is projected to cost 0.9% less than keeping both [Amos and Mountaineer] through 2040. The fact that replacing both plants in 2028 is more expensive than replacing them in 2040, but replacing only Amos in 2028 is less expensive, shows that her analysis demonstrates that Mountaineer will be cheaper than other options, and thus that cost recovery for its ELG investment from Virginia customers should be approved.[288]

Mr. Martin also challenged several of the assumptions in Ms. Kwok's analysis. He asserted that every aspect of Ms. Kwok's analysis is undermined by the inaccurate premise that APCo, which is an FRR entity, can purchase capacity in PJM's auctions.[289] He described obtaining capacity through year-to-year bilateral contracts as an unrealistic option.[290]

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[282] Tr. at 241-42, 261-63 (Beam).
[283] Tr. at 258, 261 (Beam).
[284] Tr. at 266-67 (Beam).
[285] Tr. at 243 (Beam).
[286] Tr. at 245 (Beam).
[287] Ex. 34 (Martin rebuttal) at 1.
[288] *Id.* at 2.
[289] *Id.* at 2-3; Tr. at 273, 289 (Martin).
[290] Ex. 34 (Martin rebuttal) at 3.

Mr. Martin responded to Staff witness Morris's statement that Amos's economic viability appears to be largely dependent upon whether it will be dispatched economically, or at a 69% capacity factor. Mr. Martin testified that Amos would need to lose an enormous amount of money producing energy between 2029 and 2040 to completely offset its large capacity cost advantage *and* the Commission would need to allow recovery of associated fuel costs. He described this possibility as remote.[291] He testified that even Sierra Club's high coal cost sensitivity does not produce anywhere close to enough energy losses when forced to operate at a 69% capacity factor to offset Amos's capacity cost advantage.[292]

In response to Staff witness Morris's observation that APCo's analysis includes operating losses in some individual years for Amos, Mr. Martin testified that these negative margins, which he indicated were single digit million dollar amounts in a handful of years, should not have been the modeled outcome. He emphasized that APCo's modeling projected Amos would generate positive energy margins over the entire 2028-2040 period.[293] He added that Sierra Club's analysis for Scenario (1a) projects that Amos would be profitable in total over the 2029-2040 period even if it were forced to run at a 69% capacity factor.[294]

Mr. Martin clarified that while APCo's economic analysis excluded energy margins for Amos and Mountaineer, it did include the PLEXOS-determined energy margins of every replacement resource. He described this asymmetry as handicapping Amos and Mountaineer to illustrate the point that they do not need to produce positive energy margins to be the most affordable capacity option for Virginians.[295]

Mr. Martin disagreed with the apparent suggestion that the relative differences in NPV between the cases presented in Staff witness Morris's Table 2 will change if the Commission approves a different recovery period than APCo would propose. Mr. Martin explained that none of the NPVs from any of the Company's scenarios contained any costs associated with recovery of existing plant-in-service and therefore such recovery would need to first be added to all of the scenarios and then analyzed under differing recovery periods in order to determine the impact of those periods.[296] Mr. Martin testified that the Company did not perform such an analysis because it would require speculation on multiple assumptions, which he described.[297] However, were such an analysis to be performed, he does not believe there would be much of an impact on the NPVs because the change in both timing and amount of the return on investment (return on rate base) and the change in the timing of the return of investment (depreciation expense) would come close to offsetting each other in an NPV calculation.[298]

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[291] *Id.* at 4.
[292] *Id.* at 5.
[293] *Id.* at 4.
[294] *Id.* at 5.
[295] *Id.* at 5-6. As discussed above, Staff witness Morris incorporated the PLEXOS-determined Amos and Mountaineer's projected energy margins in Staff's analysis. *Id.* at 6.
[296] *Id.* at 7.
[297] *Id.*
[298] *Id.* at 7-8.

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Regarding the use of nameplate capacity to calculate replacement capacity in his Case 3, Mr. Martin acknowledged this as an error. However, he downplayed the significance of this error since it only amounts to a 9% reduction in the cost of Case 3, which he described as an unrealistic, hypothetical scenario (capacity-only contracts).[299] He testified that the capacity price forecast could be cut in half and the cost would still exceed the incremental cost of Amos and Mountaineer continuing to serve Virginia.[300]

Turning to Ms. Kwok's Scenario (1a), Mr. Martin testified the assumption that Amos and Mountaineer would run at a 69% capacity factor even if uneconomic is unrealistic and overstates fuel costs.[301] He does not consider this scenario worthy of much consideration given APCo witness Beam's reference to the provisions of Code § 56-249.6.[302] He added that the reduction in energy margins due to uneconomic dispatch for Amos and Mountaineer would need to be eight times larger than projected by Sierra Club before it would be large enough to offset the capacity cost savings he calculated for the Company's Cases 1 and 2.[303]

Mr. Martin indicated Ms. Kwok's Scenario (2) is her only scenario that is not unduly influenced by understated replacement resource costs or uneconomic dispatch, because Amos and Mountaineer run through 2040.[304]

Ms. Kwok's Scenarios (3) and (4) include what Mr. Martin asserts are understated replacement resource costs (3 and 4) and/or overstated fuel costs from operating Mountaineer at a loss in some hours (4). Even with these assumptions, Mr. Martin indicated that Scenario (3) shows removing both Amos and Mountaineer will be $163 million more expensive than continuing to serve Virginia with them.[305] He pointed out that because Scenario (4) (removing only Amos) is less expensive than Scenario (3), this indicates that keeping Mountaineer will save customers money. He believes Ms. Kwok's Scenario (4) shows tiny savings that are "hardly enough to justify walking away from [Amos] and putting the enormous risks associated with replacing it on the Company and its Virginia customers."[306]

Mr. Martin explained that the primary resource Ms. Kwok added to replace Amos and Mountaineer is PJM market capacity, at an assumed short-term capacity price. He reiterated that APCo cannot currently purchase capacity in PJM's auction and thus is effectively assumed to participate in "an uncertain and risky perpetual cycle of seeking year-to-year bilateral capacity contracts."[307] Section I of this Report's Analysis provides his list of reasons why it would be

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[299] *Id.* at 8-9.
[300] *Id.* at 9.
[301] *Id.* at 10.
[302] *Id.* at 10-11. However, he noted that Sierra Club's workpapers for Scenario (1a) show Amos and Mountaineer remain profitable over the forecast period, just less profitable compared to Scenario (2). *Id.* at 11. Mr. Martin acknowledged uneconomic dispatch would also incur costs other than fuel costs. Tr. at 284-85 (Martin).
[303] Ex. 34 (Martin rebuttal) at 11.
[304] *Id.*
[305] At the hearing, Ms. Kwok revised the $163 million difference referenced by Mr. Martin to $184 million. Tr. at 148 (Kwok). *See, e.g.,* Ex. 23 (Kwok) at 7, 22 (difference in NPVs between Ms. Kwok's "APCo Preferred" and "Full Coal Removal from Rate Base" Scenarios).
[306] Ex. 34 (Martin rebuttal) at 12.
[307] *Id.* at 13.

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risky and inadvisable to replace the capacity of Amos and Mountaineer with short-term bilateral purchases of capacity.[308]

Mr. Martin testified further that "paper capacity" would necessarily be sourced from multiple existing fossil-fueled resources due to the sheer number of MW needed and the low capacity credit that the PJM ELCC methodology assigns to renewables.[309] He noted that Amos and Mountaineer will continue to operate past 2028, regardless of the Commission's decision in this case, and that the Commission denying cost recovery for ELG investments could result in APCo purchasing capacity from, and providing a financial lifeline to, other fossil-fuel plants.[310]

Mr. Martin confirmed that APCo has the right to choose FRR status or auction participation each year.[311]

Mr. Martin does not find Ms. Kwok's capacity price forecast to be credible because it was not based on any fundamental PJM regional economic modeling and was simply calculated in a spreadsheet.[312]

Mr. Martin believes APCo's customers would be exposed to far too much additional energy market exposure under Sierra Club's resource plan. He discussed a table he prepared to illustrate the reliance on bilateral capacity contracts, which is included in Section I of this Report's Analysis.[313]

Mr. Martin found Ms. Kwok's representations of load and generation to be misleading and confusing.[314] He also asserted that while modelers can produce resource plans based on the minimum level of capacity in planning exercises in the perfect world, the Company does not operate in a perfect world and has never maintained only the minimum amount of capacity to meet its PJM requirements. He believes a minimum 18-20% reserve margin, with a diverse set of fossil-fueled and renewable resources, is a more appropriate level of capacity, especially as dispatchable fossil-fueled capacity around PJM is retiring and being replaced with non-dispatchable renewables, which do not contribute as much at the critical times of peak loads.[315] He identified several reasons why APCo could fall short of meeting its capacity requirements, including, among other things, events that could cause load to be higher than forecasted, catastrophic equipment failure, or PJM rule changes.[316]

Mr. Martin pushed back on Sierra Club witness Kwok's claims that coal plants will become more uneconomic in the future. He believes that Amos and Mountaineer are uniquely situated, with rising fuel costs or lower energy prices not impacting these plants' capacity value and a competitive advantage over fossil-fuel plants that are in PJM's RGGI states. Citing the

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[308] *Id.* at 13-14; Tr. at 273 (Martin correction).
[309] Ex. 34 (Martin rebuttal) at 14. Mr. Martin recognized that the vast majority of PJM capacity is fossil-fueled. *Id.*
[310] *Id.*
[311] Tr. at 289-90 (Martin).
[312] Ex. 34 (Martin rebuttal) at 15.
[313] *Id.* at 15-16.
[314] *Id.* at 16-17.
[315] *Id.* at 17.
[316] *Id.* at 18.

high prices of natural gas this year, he also testified that Amos and Mountaineer can be a valuable energy hedge against natural gas plants that often set the marginal energy price in PJM.[317]

Mr. Martin testified that the third-party estimates of renewable resource costs described by Ms. Kwok grossly understate multiple components of the costs of wind and solar resources. He based this assertion on his experience during the past three years in which he has evaluated and modeled the cost of dozens of bids from resource solicitations in PJM and SPP for five AEP operating companies, including the evaluation of bids received by APCo in 2020, 2021, and 2022.[318] He testified that third-party projected costs are always much lower than real resources, as the capital cost, transmission interconnection costs, transmission network upgrades, land leases, O&M expenses, and property taxes, among other things, all tend to be understated. He stressed that developers do not price their product at what it costs to build; rather, they price their projects at what they think someone will pay for it. Given the requirements of the VCEA, he maintained that developers price their resources above the actual cost of building the resource because they know renewable resources that produce RECs would allow APCo to avoid being a price taker in the REC markets.[319] He characterized the current environment as a seller's market, and he expects high demand and higher prices to persist for some time. He also noted that Sierra Club's analysis did not account for recent inflation.[320]

He called Ms. Kwok's assertion that his analysis did not use an optimized capacity expansion and dispatch model, or that it was a simple spreadsheet model, incorrect. He explained that the analysis was based on resource selections made by the same PLEXOS model APCo has used for resource planning for 10 years, including the 2021 RPS Plan from which his inputs were taken. He elaborated that a spreadsheet was then necessary to isolate the Virginia share of the ELG investment or other ongoing costs at Amos and Mountaineer by scaling down the resources added for total company needs. He also used the PLEXOS cost inputs to convert revenue requirements from levelized lifetime values to non-levelized Virginia retail cost of service. The capacity expansion and production cost modeling were done in PLEXOS, and then spreadsheets were used to take the outputs, add what needs to be added from outside the model, and then summarize it and prepare tables and figures to illustrate the results.[321]

Mr. Martin clarified that Ms. Kwok's concern about the PJM capacity price forecast in APCo's analysis only applies to the Company's Case 3. He reiterated APCo's position that Case 3, while illustrative, is not a realistic option. He also testified that the capacity price curve could be cut in half and that option still would not be cheaper than continuing to serve Virginia customers with Amos and Mountaineer.[322]

Mr. Martin testified that Ms. Kwok's analysis overstates the impact of the REC deficiencies in APCo's modeling. He testified that APCo believes RECs will be available in

[317] *Id.* at 18-19.
[318] *Id.* at 19.
[319] *Id.* at 20.
[320] *Id.* at 21.
[321] *Id.* at 21-23.
[322] *Id.* at 22.

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publicly traded markets and does not anticipate being subject to the $45/MWh deficiency payment. He asserted that some of the understatements in REC requirements in the Company's 2021 VCEA modeling (which were since corrected in the 2022 Virginia IRP) occurred during 2022 through 2025, when APCo will not be able to bring any physical resources online in addition to those which are already in the forecast. He also indicated that there was no modeling error associated with the Buck and Byllesby plants.[323]

Mr. Martin identified two other statements from Ms. Kwok's testimony that he found misleading. First, he testified that the vast majority of the amounts listed on her Table 8 are fixed O&M, and not capital expense, and thus do not add to undepreciated plant balances. Second, while Ms. Kwok states that customers would also avoid paying for the variable costs of generation at Amos and Mountaineer if they no longer serve Virginia, she fails to mention that these variable costs will not be incurred unless it was economical to run Amos and Mountaineer and that if the plants do not run, APCo would have to purchase more expensive market energy.[324]

Mr. Martin reported that PJM's non-performance penalties are $3,000 per MWh for non-FRR entities compared to $1,200 per MWh for FRR entities. He added that, as an option available only to FRR entities, APCo can substitute overperformance at one unit to avoid a penalty for another unit's underperformance.[325] His understanding is that the FRR election must be on a total company basis.[326]

In Mr. Martin's view, Congress's recent passage of the Inflation Reduction Act as a way to combat climate change makes it less likely that Congress will also pass a carbon tax in the near-term. For this reason, he characterized an analysis of both the Inflation Reduction Act and a potential carbon tax as "probably double counting."[327]

Mr. Martin agreed that the new tax credits in the Inflation Reduction Act will help bring down the cost of renewables. However, APCo has "experienced massive increases in costs of renewables over the past year and a half" that are not incorporated in the economic analysis of either APCo or Sierra Club in this case. Although he acknowledged the Inflation Reduction Act would offset some of the higher resource costs, he maintained that APCo would also have to analyze the extent to which the Company has enough tax liability to use the extended tax credits on a timely basis. Additionally, the tax credits will increase the demand on the supply chain for renewable components, which Mr. Martin indicated has already made it problematic for other companies to obtain panels and turbines.[328]

He concluded that Amos and Mountaineer "are the most affordable capacity options for Virginia customers, and the next best option is not even close."[329] In response to news reports indicating that various industry participants are moving away from coal, Mr. Martin indicated that what might be good for some utilities or other coal plants is not necessarily the right thing

[323] *Id.* at 23-24.
[324] *Id.* at 24.
[325] Tr. at 279 (Martin).
[326] Tr. at 282 (Martin).
[327] Tr. at 280 (Martin).
[328] Tr. at 280-81 (Martin).
[329] Ex. 34 (Martin rebuttal) at 25.

for APCo's customers, which his analysis indicates is making the ELG investment at Amos and Mountaineer to maintain their affordable capacity.[330]

Mr. Ross addressed depreciation issues. He has no concern with Staff witness Morgan's recommendation that the Company incorporate Amos and Mountaineer CCR/ELG salvage values into APCo's next Virginia depreciation study. He anticipates this study will be performed in conjunction with APCo's next triennial review filing due in the first quarter of 2023. He expects the study will be based on plant-in-service balances as of December 31, 2022, and identified which E-RAC assets at issue in the instant case will (and will not) be in service by December 31, 2022.[331] For this upcoming study, APCo would consider proposing changes to Virginia jurisdictional depreciation rates for Amos and/or Mountaineer if the Commission were to reject recovery of the ELG asset(s).[332]

CODE

APCo filed its Petition pursuant to Code § 56-585.1 A 5 e, which provides in part as follows:

> 5. A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of the following costs:
>
> ...
>
> e. Projected and actual costs of projects that the Commission finds to be necessary ... to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the costs of allowances purchased through a market-based trading program for carbon dioxide emissions. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations;

Code § 56-585.1 D further states in part as follows:

> The Commission may determine, during any proceeding authorized or required by this section, the reasonableness or prudence of any cost incurred or projected to be incurred, by a utility in connection with the subject of the proceeding. A determination of the Commission regarding the reasonableness

[330] Tr. at 293-94 (Martin).
[331] Ex. 32 (Ross rebuttal) at 1-2. APCo would include in subsequent depreciation studies any E-RAC assets placed in service after December 31, 2022. *Id.* at 2.
[332] *Id.* at 4.

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> or prudence of any such cost shall be consistent with the Commission's authority to determine the reasonableness or prudence of costs in proceedings pursuant to the provisions of Chapter 10 (§ 56-232 et seq.).

The Commission has previously recognized that the unambiguous plain language of both of the above statutes applies to the instant proceeding, with the applicant utility bearing the burden of proof.[333]

In the instant case, APCo questioned this established Commission precedent, arguing as follows:

> Subsequent to the issuance of the 2021 E-RAC Order, the Virginia Supreme Court issued an opinion that directly addresses [Code § 56-585.1 D], holding
>
> > Where a statute includes a general provision with broad terms and a specific provision with narrow terms, the latter qualifies the former.
>
> Applying this precedent, [Code § 56-585.1 D], with its broad terms, cannot prevail over [Code § 56-585.1 A 5 e], with its narrow and specific terms. That is, [Code § 56-585.1 D] cannot be employed in order to avoid complying with the General Assembly's mandate that the Commission "shall" approve the Petition if the Company meets the two requirements in [Code § 56-585.1 A 5 e].[334]

The above argument appears to be one the Commission has already rejected,[335] repackaged with a selective quote from the recent *APCo 2022* opinion. The instant case is readily distinguishable from the case the Court addressed in *APCo 2022*. *APCo 2022* did not involve Code § 56-585.1 A 5 e, as the Court decided that certain asset impairment accounting provisions of Code § 56-585.1 A 8 applicable to triennial reviews override ratepayer protections of Code § 56-585.1 D. Additionally, in *APCo 2022*, the Court appears to have given significant interpretive weight to the fact that the relevant provisions of Code § 56-585.1 A 8 were enacted subsequent to the 2007 enactment of Code § 56-585.1 D, a sequence that indicated to the Court a substantive change in the law.[336] There is no such legislative sequence of events relevant to the

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[333] *See, e.g., 2021 Rider E-RAC Order*, 2021 S.C.C. Ann. Rep. at 333-334; *Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2018-00195, 2019 S.C.C. Ann. Rep. 333, 336-39, Order on Reconsideration (Nov. 14, 2019).

[334] APCo's Brief at 3-4 (quoting *Appalachian Power Co.* v. *State Corp. Comm'n, et al.*, No. 210391, at 23 (Aug. 18, 2022) ("*APCo 2022*") (footnotes omitted).

[335] *2021 Rider E-RAC Order*, 2021 S.C.C. Ann. Rep. at 333-34.

[336] *See, e.g., APCo 2022* at 24 ("If the amendments to [Code § 56-585.1 A 8] did not change the law regarding the Commission's regulatory discretion for these costs, those amendments were meaningless because subsection D has been in Code § 56-585.1 since its inception.").

instant Commission proceeding. The substantive provisions of Code §§ 56-585.1 A 5 e and 56-585.1 D were enacted as part of the same 2007 re-regulation legislation.[337] In my view, *APCo 2022* does not require the Commission to: (1) stop harmonizing contemporaneously enacted statutory provisions and (2) prospectively ignore what APCo spends on environmental compliance, which is the essence of APCo's argument. For this reason, the analysis in this Report is based on a consideration of all record evidence relevant to the reasonableness and prudence of ELG investment, including quantitative evidence and also more qualitative evidence (of certain risks, for example).

However, should the Commission decide that *APCo 2022* amended the 2007 re-regulation statute to preclude any consideration of cost, as suggested by the Company, the Commission need not consider Section I below, as there is no question ELG investment is necessary for compliance. Erasing Code § 56-585.1 D would seemingly collapse this case so that it starts and ends with the application of only one criterium – whether the costs are for projects necessary to comply with an environmental law or regulation.[338] Under this new standard (which I do not recommend), the Commission should consider Sections II and III, as they involve questions about whether costs are "necessary."[339]

Because I recommend that the Commission continue to apply Code § 56-585.1 D to the environmental compliance proceedings conducted under Code § 56-585.1 A 5 e, Section I of this Report analyzes the reasonableness and prudence of APCo's ELG investment, for which the *2021 E-RAC Order* denied cost recovery without prejudice. Section II analyzes the proposed RGGI costs challenged by Appalachian Voices. Section III analyzes the proposed dry sorbent injection project costs challenged or questioned by Sierra Club and Consumer Counsel. Section IV addresses uncontested issues.

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[337] 2007 Va. Acts chs. 888, 933. In 2014, the opening sentence of Code § 56-585.1 D was amended as follows:

> ~~Nothing in this section shall preclude the~~ *The* Commission ~~from determining~~ *may determine*, during any proceeding authorized or required by this section, the reasonableness or prudence of any cost incurred or projected to be incurred, by a utility in connection with the subject of the proceeding.

2014 Va. Acts. ch. 548.

[338] Code § 56-585.1 A 5 e. APCo's Brief indicates that the Commission must "approve the Petition if the Company meets the *two* requirements" in Code § 56-585.1 A 5 e. APCo's Brief at 4 (emphasis added). It is unclear what the second statutory requirement would be under APCo's interpretation. APCo's statement seems to refer to a prior assertion by the Company that "The evidence presented in this Petition demonstrates that the Company has met its statutory burden, set out in the plain text of [Code § 56-585.1 A 5 e], for all of the above compliance costs: they were incurred to comply with environmental laws and regulations ... and were necessary to comply with environmental laws and regulations." APCo's Brief at 2-3. As shown in the above excerpt of Code § 56-585.1 A 5 e, APCo has omitted the word "necessary" from its reference to the opening language of the statute.

[339] However, as discussed below, I view the issues raised concerning RGGI compliance costs to be relevant under Code § 56-585.1 D, which could not be considered under APCo's legal position.

I. ANALYSIS OF ELG INVESTMENT

Amos and Mountaineer

The total nameplate capacity of the coal-fired units at Amos and Mountaineer is 4,235 MW.[340] Amos has a nameplate capacity of 2,930 MW (815 MW for Unit 1, 815 MW for Unit 2, and 1,300 MW for Unit 3).[341] Mountaineer is a one-unit facility with a nameplate capacity of 1,305 MW.[342]

While jurisdictional allocation factors change over time, APCo's Petition, and the evidence of case participants, assume that Virginia's approximate share of Amos and Mountaineer is 50%,[343] which APCo assumed is approximately 2,100 MW of nameplate capacity.[344] However, the record indicates that Amos and Mountaineer's UCAP[345] value (not nameplate) is the capacity measurement used for purposes of satisfying APCo's capacity obligation in PJM.[346] The 2,100 MW "Virginia share" of Amos and Mountaineer's combined nameplate capacity equates to 1,907 MW UCAP.[347]

Annual capacity factors for Mountaineer during the last five calendar years have ranged from 46% to 71%.[348] For Virginia ratemaking purposes, Mountaineer is currently being depreciated with an assumed retirement date of 2040.[349] APCo projects that Mountaineer's net book value on December 31, 2028, excluding ELG investment, would be approximately $474 million on a total company basis.[350]

Annual capacity factors for the three units at Amos during the last five calendar years have ranged from 31% to 57%.[351] For Virginia ratemaking purposes, the Amos units are currently being depreciated with assumed retirement dates of 2032 (Units 1 and 2) and 2033 (Unit 3).[352] APCo projects that Amos's net book value on December 31, 2028, excluding ELG investment, would be approximately $582 million on a total company basis.[353]

The ELG Rule and APCo's Estimated Compliance Costs

The ELG Rule established discharge limits on FGD wastewater, transport water used for fly ash and bottom ash handling, and other wastewaters at Amos and Mountaineer. The ELG Rule, initially promulgated in 2015 and revised most recently in October 2020, eliminated the

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[340] Ex. 13 (Martin direct) at attached Sched. 1, Table 8.
[341] *See, e.g.*, Ex. 20 at 9.
[342] Ex. 13 (Martin direct) at attached Sched. 1, Table 8.
[343] *See, e.g.*, Ex. 13 (Martin direct) at 9-10.
[344] *Id.* at 18.
[345] As defined above, "UCAP" refers to unforced capacity.
[346] *See, e.g.*, Ex. 13 (Martin direct) at 9-10; Ex. 30 (Morris) at 11.
[347] Ex. 13 (Martin direct) at 10, 18; Ex. 30 (Morris) at 7.
[348] Ex. 23 (Kwok) at attached Ex. SK-11.
[349] Ex. 10 (Ross direct) at 10; Ex. 31 (Morgan) at 4-5.
[350] Ex. 10 (Ross direct) at 11.
[351] Ex. 23 (Kwok) at attached Ex. SK-11.
[352] Ex. 10 (Ross direct) at 10; Ex. 31 (Morgan) at 4-5.
[353] Ex. 10 (Ross direct) at 11.

discharge of most ash transport waters and requires enhanced treatment of FGD wastewaters. These requirements are implemented through modifications to the existing state wastewater discharge (NPDES) permit at each facility.[354] The ELG Rule requires that discharge limits be achieved as soon as possible before December 31, 2025, pursuant to a schedule in each facility's NPDES permit. New bioreactors would bring Amos to full ELG compliance by the end of 2023 and an upgraded bioreactor would bring Mountaineer into ELG compliance by the end of 2023.[355]

At Mountaineer, the current total estimated cost for ELG compliance is approximately $42 million on a total company basis, with Virginia's share approximately $21 million.[356] At Amos, the current total estimated cost for ELG compliance is approximately $127 million on a total company basis, with Virginia's share approximately $63.5 million.[357]

Reasonableness and Prudence Standard

In denying cost recovery of the ELG investment, the *2021 E-RAC Order* found "it is critically important to analyze the overall impact of this investment on both customer rates and reliability" but that the record of the prior case was "lacking in both regards."[358] The Commission found that APCo did not establish in the 2021 E-RAC Case "that the ELG investment is reasonable and prudent from an economic or a resource adequacy perspective."[359]

Sierra Club correctly recognized[360] that the Commission typically evaluates prudence based on the time a decision is made to incur costs.[361] While Sierra Club indicated the Commission could apply the prudence standard this way in the current case, Sierra Club indicated doing so was complicated by a WVPSC ruling that West Virginia would pay for up to 100% of the ELG investment if Virginia decides not to pay an allocated portion. Given this development, Sierra Club asserted that the Commission could consider a broader range of evidence to decide what is in the best interests of Virginia today.[362] As framed by Consumer Counsel, this case is about "with information available today, what resource option best promotes the lowest-reasonable cost for reliable electric service in a manner that complies with applicable laws, including the [VCEA]."[363]

I generally agree with Sierra Club's legal analysis concerning the prudence standard. Application of the prudence standard based on information at the time of a management decision typically involves a situation where there is the potential for a disallowance of the subject costs.

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[354] Ex. 9 (Spitznogle direct) at 5.
[355] *Id.* at 6-7.
[356] Ex. 8 (Sherrick direct) at 9-10; Tr. at 63-64 (Sherrick).
[357] *Id.*
[358] *2021 E-RAC Order*, 2021 S.C.C. Ann. Rep. at 334.
[359] *Id.*
[360] Tr. at 26, 35 (Johns); Sierra Club's Brief at 2-3.
[361] *See, e.g., Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2018-00095, 2019 S.C.C. Ann. Rep. 328, 330, Final Order (Aug. 5, 2019).
[362] Tr. at 26, 35 (Johns).
[363] Consumer Counsel's Brief at 2.

However, that is not the current situation because the WVPSC, as discussed further below, has ruled that West Virginia would pay for up to 100% of the ELG investment if Virginia decides not to pay an allocated portion. Since ELG investment and associated cost recovery are going forward one way or the other, the question in the instant case does not seem to be whether it was prudent for APCo to make this investment. Rather, in my view, the question for the Commission is whether it is reasonable and prudent for APCo to allocate a share of this cost to Virginia. I also note the *2021 E-RAC Order* stated that APCo "should be permitted to provide additional analyses and evidence to support this ELG investment."[364] Accordingly, I have considered all of the evidence in this case in my analysis of APCo's proposed allocation of ELG investment to Virginia, given the unique circumstances of this case.

WVPSC ELG Order

The WVPSC issued orders on two issues that inform case participants' positions on the economic analyses in the instant case. Consumer Counsel asserted that these orders and testimony in the instant Commission case "call into question whether Virginia customers would be treated equitably without support from this Commission."[365]

First, the WVPSC issued an order indicating that its approval of ELG investment would cover, with FERC jurisdictional customers, up to 100% of the associated post-2028 costs if the Commission were not to approve ELG investment.[366] APCo indicated that one implication of the WVPSC order approving up to 100% cost recovery, as described above, is that Amos and Mountaineer will continue to be an integral part of APCo's FRR capacity plan and these plants will continue to operate and dispatch past 2028, regardless of the Commission's decision in the instant case.[367] Counsel for APCo indicated that the question for the Commission is "not can this Commission shut down the operations of these plants. It cannot...."[368] Construction of the ELG infrastructure at Amos and Mountaineer began after the WVPSC granted its approval.[369]

Because Amos and Mountaineer will continue to operate beyond 2028 regardless of the Commission's decision, there is no need in the instant case for the Commission to assess reliability from a system impact standpoint, including the potential for any upgrades necessary to maintain reliability upon retirement(s).[370] Additionally, APCo's economic analysis offered in

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[364] *2021 E-RAC Order*, 2021 S.C.C. Ann. Rep. at 334.

[365] Consumer Counsel's Brief at 4.

[366] Ex. 18 (October 12, 2021 WVPSC Order) at 14 (including conclusions that (i) unless the Commission "authorize[s] ELG improvements, West Virginia and FERC jurisdictional customers benefitting from [Amos and Mountaineer] beyond 2028 shall pay the reasonable and prudent ... ELG compliance costs and ... ongoing operations costs incurred solely to keep the [p]lants open past 2028;" and (ii) unless the Commission allows "Virginia jurisdictional customers of APCo to pay for their share of costs for ELG improvements and continuing operations costs necessary to operate beyond 2028, the benefit of capacity and energy made possible by the improvements and operating beyond 2028 shall inure to the benefit of West Virginia customers and FERC jurisdictional customers."). References to the Kentucky Public Service Commission in these conclusions, omitted from the above parenthetical, pertain to investment in the Mitchell station, which is irrelevant to Virginia ratepayers.

[367] Ex. 11 (Beam direct) at 4.

[368] Tr. at 16 (Coates).

[369] *See, e.g.*, Tr. at 89 (Beam).

[370] However, Mr. Martin's economic analysis in the instant case includes no transmission costs because Amos and Mountaineer will not retire in 2028. Ex. 13 (Martin direct) at 27.

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support of its Petition does not include any such transmission costs.[371] From a resource adequacy perspective, APCo indicated that WVPSC's ratemaking support means that Amos and Mountaineer will continue to be an integral part of APCo's FRR capacity plan.[372]

The part of the order that got Consumer Counsel's attention is the WVPSC's declaration that if West Virginia were to cover all of the ELG investment and post-2028 costs, APCo's West Virginia jurisdiction would be entitled to 100% of the benefits from Amos and Mountaineer. Consumer Counsel pushed back on such a conclusion, when paired with APCo's stated expectation that Virginia would nonetheless bear some cost responsibility after 2028 for the remaining net book value of Amos and Mountaineer. Consumer Counsel stated as follows:

> First, if it is the public policy of West Virginia to continue the operation of [Amos and Mountaineer], without regard to economics, and to declare that all capacity and energy is to be assigned to West Virginia, then West Virginia will need to take ownership of that policy and all associated costs. If APCo and West Virginia were to seek to cordon off all capacity and energy associated with [Amos and Mountaineer], then the West Virginia jurisdiction will need to take cost responsibility for all O&M, capital investments, and depreciation for [Amos and Mountaineer]. Simply put, the West Virginia jurisdiction cannot fairly obtain *all* of the benefits associated with [Amos and Mountaineer] without bearing *all* of the costs.
>
> Second, the proposal to charge Virginia customers depreciation expense for a generation facility that would be used solely to serve and benefit the West Virginia jurisdiction is contrary to traditional concepts of utility ratemaking. If appealing to traditional ratemaking, then a utility may be permitted to recover from customers only costs associated with investments that are used and useful in providing them with electric service. If all capacity and energy were siphoned away from the Virginia jurisdiction post-2028, this would mean that [Amos and Mountaineer] would no longer be used and useful in providing electric service to the Virginia jurisdiction.
>
> Finally, the statement that the Virginia jurisdiction would have no "claim" to the capacity of [Amos and Mountaineer] is inconsistent with the realities of PJM's Reliability Assurance Agreement, which is a federally accepted agreement. Notwithstanding APCo's veiled threats that Virginia customers would not be entitled to capacity from [Amos and Mountaineer] if the ELG investments are denied, the Company does elsewhere seem to recognize this reality. That is, APCo admits that [Amos and Mountaineer] will

[371] *Id.*

[372] Ex. 11 (Beam direct) at 9.

> continue to be an "integral component of the Company's [Fixed Resource Capacity "("FRR")] capacity plan. Because PJM views APCo as [a] whole[,]" there is no such thing as a "West Virginia FRR plan" and a "Virginia FRR plan" - there is only one FRR plan for APCo. If the capacity associated with [Amos and Mountaineer] is included in APCo's FRR Plan, then that necessarily means that the capacity will be used to satisfy *(i.e.,* serve to benefit) the capacity obligations of both the West Virginia and Virginia jurisdictions.
>
> As discussed in more detail below, APCo can with limited notice, elect to terminate its FRR status. That is going forward, APCo could satisfy its capacity obligation using PJM's ... capacity auctions. In this event, [Amos and Mountaineer] could receive unit-specific revenues associated with their respective capacity. With unit-specific revenues, it becomes easier to imagine some intra-company arrangement between the state jurisdictions, as discussed by APCo. While it is perceivable that the WVPSC could attempt to order APCo to flow all such capacity revenue to the West Virginia jurisdiction, this would not be fair to the Virginia jurisdiction if the Virginia jurisdiction remains responsible for its share of depreciation.[373]

WVPSC 69% Capacity Factor Orders

The WVPSC issued orders that Sierra Club believes require APCo to operate Amos and Mountaineer at a 69% capacity factor.[374] Sierra Club witness Kwok described the fact that APCo's analysis did not consider the impact that uneconomic coal generation could have on energy costs or revenues "a large oversight", given the WVPSC order that she believes required APCo to run Amos and Mountaineer at a 69% capacity factor.[375] She recommended the Commission fully consider the risk of uneconomic dispatch to Virginia ratepayers when evaluating whether Virginia should approve the proposed ELG costs.[376] Based on her modeling assumptions, Ms. Kwok's modeling results show an approximately $173 million or $346 million Virginia jurisdictional NPV cost of a 69% capacity factor requirement.[377]

Mr. Beam testified that APCo has asked for more clarity regarding the 69% capacity factor, as well as confirmation that the costs of uneconomic dispatch of Amos and Mountaineer would be borne only by West Virginia customers.[378] Pending clarification,[379] APCo does not

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[373] Consumer Counsel's Brief at 6-7 (citations omitted).
[374] *See, e.g.,* Sierra Club's Brief at 4-8.
[375] Ex. 23 (Kwok) at 10.
[376] *Id.* at 37-38.
[377] *See, e.g.,* Ex. 23 (Kwok) at 22 (showing $173 million as the difference between her Scenario (1a) (West Virginia PSC Preferred) and Scenario (2) (APCo Preferred) and $346 million as the difference between her Scenario (1b) (West Virginia PSC Preferred, high coal price) and Scenario 2 (APCo Preferred)).
[378] Ex. 33 (Beam rebuttal) at 2.
[379] No such clarification had been provided when APCo filed its brief in this case. APCo's Brief at 8, n.25.

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intend to run the plants uneconomically and is not currently running these plants to try to achieve a 69% capacity factor.[380] Mr. Beam also testified in response to the questioning by Consumer Counsel as follows:

> Q ... -- if the West Virginia Commission does require APCo to run generation facilities in an uneconomic manner, would [APCo] seek cost recovery in Virginia of such uneconomic costs necessary to comply with the West Virginia directive?
>
> A No, we would not.[381]

Sierra Club asserted that while the Commission may possess the legal authority to disallow any fuel costs it deems imprudent as a result of any uneconomic dispatch (if mandated), doing so would either be practically impossible or very challenging and burdensome.[382]

Case Participants' Positions on ELG Investment

APCo framed the ELG investment as about capacity and indicated that APCo does not need Amos or Mountaineer for energy.[383] APCo argued that only its analysis is compelling and credible,[384] and that key assumptions used in Sierra Club's economic analysis are fundamentally flawed.[385] Among the key assumptions challenged by the Company, APCo argued that there is no mandate to run Amos or Mountaineer at a 69% capacity factor;[386] APCo cannot purchase capacity from the PJM auctions;[387] securing replacement capacity through short-term, bilateral capacity contracts is an imprudent utility practice;[388] and the price of renewable replacement capacity is not guaranteed to decrease.[389]

Staff found that the economic analysis in this case indicates the continued operation of Mountaineer with the necessary ELG investment is a lower cost resource option compared to alternatives. Staff was unable to reach a conclusion on the Amos ELG investment.[390]

The Coal Association argued that the relatively small cost of the ELG improvements would secure an invaluable hedge against increasingly unpredictable energy market volatility. The Coal Association further argued that the billions of dollars it would cost to replace Amos and Mountaineer "pales in comparison" to the cost of the ELG investment.[391] The Coal Association also believes that when the risk of uneconomically dispatching Amos is removed

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[380] Tr. at 253-54 (Beam).
[381] Tr. at 268 (Beam).
[382] *See, e.g.*, Sierra Club's Brief at 8-10.
[383] *See, e.g.*, Tr. at 16 (Coates).
[384] APCo's Brief at 7-9.
[385] *Id.* at 9-17.
[386] *Id.* at 10-11.
[387] *Id.* at 11-12.
[388] *Id.* at 12-15.
[389] *Id.* at 15-17.
[390] *Id.* at 4.
[391] Coal Association's Brief at 1, 3-5.

from the economic analyses in this case, approval of the ELG improvements and cost recovery is clearly economical for Virginia ratepayers.[392]

Consumer Counsel argued that it is wrong to assume that Virginia would have "no claim" to the value of Amos and Mountaineer if the ELG investment is denied.[393] Consumer Counsel also found it unclear whether APCo satisfied its burden that incurring all costs of the ELG investment represents the best resource option for customers based on at least three issues with APCo's economic analysis. First, Virginia customers do not need to replace capacity for which they would be paying. Second, APCo's economic analysis takes an all-or-nothing approach to replacing Amos and Mountaineer. Third, APCo misstates PJM's rules, resulting in a potential missed opportunity for a lower-cost resource option.[394] Consumer Counsel believes APCo's plans to retire Amos have been inconsistent, to the detriment of customers.[395]

Sierra Club argued that APCo's economic analysis is incomplete, untimely, and fundamentally flawed.[396] Sierra Club argued further that APCo failed to address significant risks associated with the Company's preferred resource plan.[397] If the WVPSC orders mean the "ship [has] sailed" on whether Amos and Mountaineer will retire, Sierra Club believes that "[t]he real question for this Commission, then, is whether it makes sense for Virginia customers to strap themselves to that ship and become subjects to, in the Company's telling, 'the whims' of the [WVPSC]."[398]

APCo's Economic Analysis

APCo's Petition analyzed the incremental Virginia cost of service for four scenarios – one where ELG is made, with Amos and Mountaineer continuing to operate through 2040; two scenarios in which APCo replaces the capacity of Amos and Mountaineer beginning in 2029 with different generic resources identified through PLEXOS modeling conducted for the 2021 RPS Plan (Cases 1 and 2); and a scenario in which the capacity of Amos and Mountaineer is replaced with "paper capacity" (Case 3). Staff modified APCo's results to incorporate an energy margin for Amos and Mountaineer,[399] which APCo indicated it had excluded for Amos and Mountaineer (but not other resources) to illustrate that Amos and Mountaineer need not produce positive energy margins to be the most affordable capacity option for Virginians.[400] Staff also modified APCo's results to correct the amount of "paper capacity" that corresponds to Amos and Mountaineer,[401] which APCo acknowledged was an error in the Petition's analysis.[402]

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[392] *Id.* at 1-2, 5-6.
[393] *Id.* at 4-8.
[394] *Id.* at 8-13.
[395] *Id.* at 14-16.
[396] Sierra Club's Brief at 4-16.
[397] *Id.* at 17-18.
[398] *Id.* at 1-2.
[399] Ex. 30 (Morris) at 11-12.
[400] Ex. 34 (Martin rebuttal) at 5-6. As discussed above, Staff witness Morris incorporated the PLEXOS-determined Amos and Mountaineer's projected energy margins in Staff's analysis. *Id.* at 6.
[401] *See, e.g.*, Ex. 30 (Morris) at 12.
[402] Ex. 34 (Martin rebuttal) at 8-9.

The Petition's NPV results, as filed and with these two Staff modifications, are shown below.[403]

Scenario	As Filed	As Modified by Staff
	NPV of 2029-2040 (in millions)	
ELG Investment – APCo's Proposal	$647	$569 (w/energy margin)
Case 1 – Renewables and Gas (RPS Port. 3)	$1,935	$1,935
Case 2 – Renewables and Storage (RPS Port. 4)	$2,290	$2,290
Case 3 – Capacity Contracts	$1,486	$1,350 (1,907 MW)

As shown above, Cases 1 and 2 reflect a significant cost of adding renewable, natural gas, and/or storage facilities to replace the capacity of both Amos and Mountaineer. As explained by APCo witness Martin, PJM assigns capacity values lower than nameplate ratings and much more nameplate capacity is required for intermittent resources to match the UCAP value of dispatchable facilities like Amos and Mountaineer.[404] Mr. Martin presented the following tables showing the resource composition and costs of Cases 1 and 2 in his analysis.[405]

Table 1 - Case 1 Replacement Resource Plan Cost

	Case 1 - Virginia Jurisdictional				
Resource Type	MW Nameplate	MW UCAP	Capital Cost ($MM)	2029 Gross Cost of Service ($MM)	2029 Net Cost of Service ($MM)
Under Development Wind/Solar	249	54	$420	$40	$18
Generic Owned Wind	200	22	$311	$25	$6
Generic PPA Wind *	150	17	$216	$20	$5
Generic Owned Solar	-	-	$0	$0	$0
Generic PPA Solar *	300	117	$355	$33	$12
Storage	300	210	$321	$61	$59
Hybrid Solar/Storage	0	0	$0	$0	$0
EE / VVO	67	67	$0	$19	$2
Gas CC	1,420	1,420	$1,546	$203	$188
Totals	2,686	1,907	$3,169	$400	$291

* PPA Capital Investment by PPA Counterparty. PPA cost is PPA price times energy

[403] Ex. 30 (Morris) at 10, 12.
[404] Ex. 13 (Martin direct) at 18.
[405] *Id.* at 13.

Table 2 - Case 2 Replacement Resource Plan Cost

	Case 2 - Virginia Jurisdictional				
Resource Type	MW Nameplate	MW UCAP	Capital Cost ($MM)	2029 Gross Cost of Service ($MM)	2029 Net Cost of Service ($MM)
Under Development Wind/Solar	249	54	$420	$40	$13
Generic Owned Wind	200	22	$309	$25	$2
Generic PPA Wind *	100	11	$142	$12	($0)
Generic Owned Solar	600	234	$843	$88	$37
Generic PPA Solar *	300	117	$388	$33	$7
Hybrid Solar/Storage	197	93	$280	$27	$14
EE / VVO	178	178	$0	$27	($10)
Storage	1,711	1,198	$1,862	$299	$284
Totals	3,535	1,907	$4,244	$551	$346

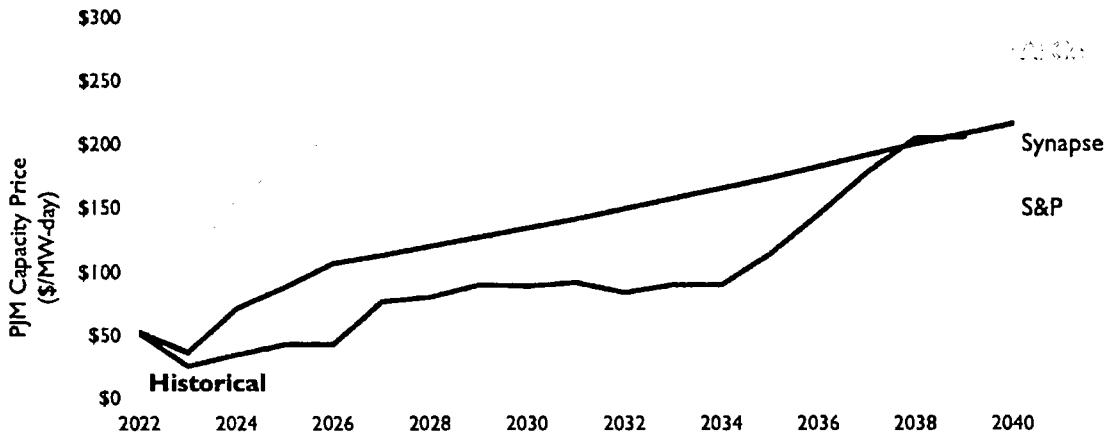
As shown, the estimated capital cost for the Case 1 resources, including 1,420 MW of combined-cycle gas, is approximately $3.2 billion. The estimated capital cost for Case 2 resources, including 1,711 MW of energy storage, is approximately $4.2 billion.[406] The $291 million and $346 million total amounts for the column on the far right are intended to show the immediate (*i.e.*, 2029) Virginia cost-of-service impact of the replacement generation, with such amounts net of fuel savings from all new resources.[407] From these amounts, Mr. Martin netted out his $73 million of avoided 2029 ongoing costs at Amos and Mountaineer to calculate 2029 cost-of-service increases of $218 million (Case 1) and $273 million (Case 2).[408] He indicated these incremental costs represent a customer rate increase between 17% and 21% in 2029 above what customers paid in 2021.[409] Shown as "[u]nder [d]evelopment" in both of these tables as an assumed (50%) Virginia share of 249 MW, Case 1 and Case 2 include the mixture of owned and PPA wind and solar projects that were selected from the 2021 RFP totaling 498 MW (nameplate) that the Commission approved in the 2021 RPS Proceeding, which will come online at various dates between 2023 and 2025.[410]

Beyond Staff's modifications, several aspects of APCo's analysis were challenged or questioned by case participants, including the assumed cost of replacement resources in Cases 1 and 2. For the "[u]nder [d]evelopment" resources, APCo used the actual resource costs. For the remaining renewable replacement resources, APCo used generic resource costs, including wind and solar costs aligned with the average of the bids received by APCo in RFPs it issued for both owned and PPA resources in 2021. As such, all new wind and solar resource costs are based on actual market information available when the analysis was performed.[411] Sierra Club used the same figures[412] but asserted that APCo's assumed cost of replacement resources based

[406] *Id.* at 14.
[407] *Id.*
[408] *Id.*
[409] *Id.* at 15.
[410] *Id.* at 12.
[411] *Id.* at 21-23.
[412] Tr. at 195 (Kwok)

on 2021 data became stale with the passage of the Inflation Reduction Act of 2022, which Sierra Club indicated significantly reduced the cost of wind, solar, and storage by extending tax credits through at least 2032.[413] While APCo agreed that the tax credits in the Inflation Reduction Act will help lower the cost of renewables, the Company responded that it has "experienced massive increases in costs of renewables over the past year and a half" that are not incorporated in the economic analysis of APCo (or Sierra Club) in this case.[414] Company witness Martin reported that the Producer Price Index Final Demand-Energy that measures commodity inflation specifically for the types of materials used in the energy industry grew from 100.8% to 170.97% from January 2021 to July 2022.[415] Sierra Club witness Kwok recognized that the numbers used by APCo (and her) preceded this "price spike" identified by APCo.[416] Additionally, the Company indicated, among other things, that the tax credits will increase the demand on the supply chain for renewable components, which APCo indicated has already made it problematic for other companies to obtain panels and turbines.[417] APCo witness Martin pointed out that while reduced renewable costs might have been a trend until two or three years ago, that trend changed dramatically, coinciding with the enactment of the VCEA.[418] The record establishes that relevant industry costs have significantly increased in 2021 and 2022, but that the Inflation Reduction Act should lower such costs. I find the net effect of these opposite forces remains to be seen and is difficult to predict at this time. Accordingly, I find it was reasonable for APCo not to update its assumed replacement costs for Cases 1 and 2 in the middle of this proceeding.

Another aspect of APCo's analysis that was challenged or questioned by case participants, is the assumed price of "paper capacity" replacement resources in Case 3. Sierra Club witness Kwok illustrated APCo's assumed capacity price in Case 3 with the top line in the chart below, and with other lines illustrating an S&P forecast (bottom line) and the assumed capacity price used in her modeling analysis (middle "Synapse" line).[419]



[413] *See, e.g.*, Sierra Club's Brief at 12-13.
[414] Tr. at 280-81 (Martin).
[415] Ex. 34 (Martin rebuttal) at 21.
[416] Tr. at 194-95 (Kwok).
[417] Tr. at 280-81 (Martin).
[418] Ex. 34 (Martin rebuttal) at 19-21.
[419] Ex. 23 (Kwok) at 20.

Ms. Kwok pointed out that APCo's forecast includes prices of $100/MW-day to $151/MW-day for 2023 and 2024, which are three to four times higher than the actual auction clearing price of $34/MW-day she believes was relevant for PJM's 2023/2024 delivery year.[420] She further indicated that APCo's capacity forecast was prepared in July 2021, before significant changes to the PJM capacity market.[421] While she acknowledged there is much uncertainty around future PJM capacity prices, she believes her alternative capacity price input values are a plausible future for prices and are more up-to-date and representative of current market conditions than APCo's forecast.[422] She testified that her capacity value inputs are a blend of a May 2022 S&P forecast and APCo's July 2021 forecast.[423] According to Ms. Kwok, a recent report by PJM's market monitor indicated approximately 12,000 MW of capacity that was offered in the capacity auction for 2023/2024 did not clear. This indicates to her that surplus capacity is available to be purchased. Additionally, a $34 per MW-day clearing price suggests to her that surplus capacity could be purchased competitively.[424]

APCo downplayed its Case 3, indicating it is an unrealistic and risky option. APCo witness Martin testified that even if the Company's capacity price curve were cut in half, this option still would not be cheaper than continuing to serve Virginia customers with Amos and Mountaineer.[425] APCo added that it cannot currently purchase capacity in PJM's auction and thus is effectively assumed to participate in "an uncertain and risky perpetual cycle of seeking year-to-year bilateral capacity contracts."[426] Mr. Martin identified the following as reasons why it would be risky to replace the capacity of Amos and Mountaineer with short-term bilateral purchases of capacity:

> 1. APCo and the AEP East companies meet their PJM capacity requirements under the FRR option. The Companies self-supply capacity, and therefore cannot buy capacity in the PJM capacity market.
>
> 2. Capacity would have to be sourced from bilateral contracts signed with individual resources. The year-to-year bilateral capacity market is not a liquid or predictable market in the experience of the Company and its affiliates.
>
> 3. PJM requires that capacity used to meet an FRR utility's capacity requirement be provided from actual physical resources. That is, although it may be referred to as paper capacity because it can be obtained under a contract, there must be real resources supporting the contracts. In addition, a resource can only be used towards one entity's PJM obligation, so the universe of resources is limited to resources not already committed to other parties.

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[420] *Id.* at 17 and attached Ex. SK-4.
[421] *Id.* at 17-18 (referencing changes to PJM's minimum offer price rule, market seller offer cap, and effective load carrying capability). While Ms. Kwok was not aware of whether aspects of PJM's minimum offer price rule are currently on appeal, she believes APCo should study ratepayer impacts of the expanded minimum offer price rule is reinstated in some form by FERC. Tr. at 183-84 (Kwok).
[422] Ex. 23 (Kwok) at 18-19.
[423] Tr. at 173 (Kwok).
[424] Tr. at 170 (Kwok).
[425] Ex. 34 (Martin rebuttal) at 22.
[426] *Id.* at 13.

4. Due to the small percentage capacity credit assigned to renewable resources by PJM, these contracts would most likely have to be with other fossil-fueled resources. If the Sierra Club's goal of opposing [Amos and Mountaineer] is to close fossil-fueled resources, this plan would not advance that goal.

5. There is competition for whatever capacity is available for bilateral contracts.

6. As short-term capacity contracts do not entitle the Company to any energy, exposure to the volatile energy market and natural gas prices would increase.

7. Each year would bring new uncertainty regarding the availability of, and price for, bilateral capacity.[427]

APCo acknowledged that PJM's rules allow the Company to decide whether or not it will continue as an FRR-entity in the future.[428]

I find that, in the context of the relevant scenarios, Sierra Club's assumed market capacity price curve for the relevant years (2029-2040) is no less plausible than the curve APCo used for its Case 3. There is no question that the auction results for PJM's 2023/2024 delivery year are far below the price levels forecasted by APCo.[429] However, this foretells little about the future price for (auction or bilateral) capacity in 2029 through 2040, which is the period relevant to the ELG investment. For 2029 through 2040, APCo's price curve is basically a straight line with a 2% upward slope.[430] As shown above, Sierra Club's lower price capacity curve over these same years also has a fairly constant slope that is comparable, but slightly steeper, than APCo's. Given the undynamic nature of APCo's and Sierra Club's data for these years, the forecasted cost in 2029 – *i.e.*, the starting point of the comparably sloped lines – appears to be a key differentiating factor between the forecasted figures for 2030 through 2040. APCo's forecasted capacity price of $222/MW-day for 2029[431] does appear high today, but as recognized by Sierra Club witness Kwok, there is much uncertainty about the future of capacity prices in PJM[432] (and perhaps what PJM's capacity market design will look like once intermittent resource have a higher penetration in PJM).

Sierra Club challenged APCo's assumption that if Virginia did not fund ELG investment the Company would need to build and/or purchase an amount of replacement capacity equal to the UCAP value of Amos and Mountaineer. Instead, Sierra Club asserted that the Company should only build or purchase the amount of firm capacity needed to meet its forecasted 14.9% reserve margin[433] (which equates to 8.6% on a UCAP basis).[434] APCo asserted that a minimum 18-20% reserve margin, with a diverse set of fossil-fueled and renewable resources, is

[427] *Id.* at 13-14; Tr. at 273 (Martin correction).
[428] Tr. at 289-90 (Martin). *See also* Ex. 25; Tr. at 168-70, 180-81 (Kwok).
[429] Ex. 23 (Kwok) at 17 and attached Ex. SK-4.
[430] The annual increases in APCo's forecasted capacity prices over this period range from $4.46 (2.0%) in 2030 to $4.82 (1.8%) in 2040. *Id.* at attached Ex. SK-4.
[431] *Id.* at attached Ex. SK-4.
[432] *Id.* at 19.
[433] *Id.* at 10-11.
[434] Ex. 13 (Martin direct) at 16.

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a more appropriate level of capacity.[435] APCo also indicated that one benefit of FRR status is that it has historically required a lower capacity obligation than auction participation.[436] However, if APCo's economic analysis proposes reserve margins increasing to nearly 39% by 2040 in a future where Amos and Mountaineer are not retired, Sierra Club described APCo's statements about the FRR benefit of a lower capacity obligation as "farcical."[437] Consumer Counsel believes APCo's own evidence in this regard "exposes the hypocrisy embedded in [APCo's] position."[438]

I find that the evidence introduced by APCo indicates that the analytical addition of 1,907 MW UCAP – by 2029 – as an alternative to Virginia funding ELG investment pushes the Company's expected reserve margin well above the 18-20% nameplate level[439] (or the corresponding UCAP level) that the Company itself indicates is appropriate. As an initial matter, I note that the relatively high projected reserve margins highlighted by Sierra Club and Consumer Counsel are for RPS Portfolio 1 and are on a UCAP (not nameplate) basis.[440] As shown below for the years 2022 through 2040, APCo provided the same projected UCAP reserve margin percentages for the other RPS portfolios, including RPS Portfolios 3 and 4 on which APCo based its Case 1 and Case 2 resource additions.[441]

[435] Ex. 34 (Martin rebuttal) at 17.
[436] Tr. at 196 (Kwok).
[437] Sierra Club's Brief at 15.
[438] Consumer Counsel's Brief at 12.
[439] Parts of the record reference "ICAP", which corresponds to nameplate capacity. Ex. 13 (Martin direct) at 16.
[440] *Compare, e.g.*, Ex. 13 (Martin direct) at attached Sched. 1, Table 30, to Tables 24-29. The "capacity reserves (MW) with new additions" figures in Tables 24-29 approaches zero for years when Table 30 shows a capacity reserve margin at or near the required 8.6% UCAP level projected by APCo.
[441] *Id.* at attached Sched. 1, Table 30.

Portfolio 3	Portfolio 4
2028 AM+MNTR Ret. RGGI CO2 Gas Option	2028 AM+MNTR Ret. RGGI-$15 CO2 No Gas Option
14.4	14.6
13.4	14.1
14.4	15.8
16.3	22.8
21.0	32.6
20.7	47.1
9.0	8.7
9.2	8.7
10.1	12.7
14.3	25.1
14.8	24.9
15.6	27.1
16.5	26.9
17.3	27.8
23.2	35.3
24.4	15.6
19.8	8.9
19.8	8.7
13.7	8.6

APCo's economic analysis in the instant case takes an assumed Virginia share of the resources added in these two portfolios through the year 2028, which show 9.0% and 8.7% (UCAP) reserve margins. APCo's supporting data indicates the projected 9.0% and 8.7% levels equate to 19 MW and 5 MW above the 8.6% projected reserve margin requirement.[442] Because both of these RPS portfolios assume the retirement of Amos and Mountaineer during 2028 (illustrated by the drops from 20.7% and 47.1% in 2027), the 3,814 MW UCAP capacity of these plants would need to be added back to the resources in these portfolios to better reflect APCo's resource portfolio in Case 1 and Case 2 presented in the instant proceeding. These RPS portfolios plan for scenarios in which Amos and Mountaineer are retired by adding large new natural gas or storage resources that would be used to serve both Virginia *and* West Virginia. Since Amos and Mountaineer are not retiring, removing the West Virginia share of such new resources is appropriate to calculate the projected total company reserve margin that would be

[442] *Id.* at attached Sched. 1, Tables 26-27.

produced from APCo's Cases 1 and 2.[443] The net effect of these adjustments is that Case 1 and Case 2 would include, as of January 1, 2029, approximately 2,400 UCAP MW and 2,600 UCAP MW above APCo's projected 8.6% UCAP reserve margin, respectively. I agree with APCo that many reasons may support targeting reserve levels above a minimum 8.6% UCAP (14.9% ICAP) reserve margin.[444] But 2,400 to 2,600 UCAP MWs is a lot of surplus capacity for a utility that had peak summer and winter demands below 6,000 MW in 2021[445] and that forecasts its peak demand will decrease from 2022-2036.[446] Consequently, APCo's assumption that the Company would or should add the equivalent of a Virginia share of Amos and Mountaineer's UCAP capacity in a scenario where both resources remain operational for APCo appears to be based on matters of interjurisdictional equity, as discussed below, rather than any projected resource adequacy need. APCo's capacity obligation – currently met through the voluntary FRR option – is assessed based on the entire Company, and not by jurisdiction.[447]

APCo's RPS Plan Economic Analysis

Staff recognized that utility resource investment is typically evaluated on a total system basis that attempts to determine the projected NPV change in a utility's total system generation portfolio resulting from the inclusion, or exclusion, of a resource being considered. Staff presented the results of such an analysis presented by APCo in its 2021 RPS Plan Proceeding, as shown below.[448]

Scenario	Portfolio 3 vs. Portfolio 1	Portfolio 4 vs. Portfolio 2
	NPV in millions	
With ELG Facilities	$21,620	$24,710
Without ELG Facilities	$22,863	$27,245
Benefit of ELG Facilities	$1,242	$2,535

Sierra Club's Economic Analysis

Sierra Club witness Kwok presented the results of economic modeling she conducted using the following four scenarios and one fuel price sensitivity:

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[443] More specifically, Case 1 adds approximately 1,400 MW (nameplate and UCAP) of natural gas as replacement resources, which corresponds to the approximately 2,800 MW of natural gas added in RPS Portfolio 3 to help replace Amos and Mountaineer. *Compare* Ex. 13 (Martin direct) at Attached Sched. 1, Table 26 with his Table 1, p. 13 of Ex. 13 (Martin direct). Case 2 adds approximately 1,711 MW of nameplate storage that corresponds to the 3,575 MW of storage added in RPS Portfolio 4 to help replace Amos and Mountaineer. *Compare* Ex. 13 (Martin direct) at Attached Sched. 1, Table 27 with his Table 2, p. 13 of Ex. 13 (Martin direct). There is no apparent reason to assume West Virginia would take on the 1,400 MW of additional natural gas or the approximately 1,200 UCAP of additional storage if Amos and Mountaineer remain operational. The net effect of adding Amos and Mountaineer but subtracting 1,400 MW of natural gas from RPS Portfolio 3 puts APCo's Case 1 approximately 2,400 UCAP above its projected 8.6% reserve margin. The net effect of adding Amos and Mountaineer but subtracting 1,200 UCAP of additional storage puts APCo's Case 2 approximately 2,600 UCAP above its projected 8.6% reserve margin.

[444] Ex. 34 (Martin rebuttal). at 17-18.

[445] Ex. 13 (Martin direct) at attached Sched. 1, Section 3.1.

[446] *Id.* at attached Sched. 1, Section 3.4.

[447] *See, e.g.*, Tr. at 282 (Martin).

[448] Ex. 30 (Morris) at 15.

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(1a) a scenario that includes ELG investments at Amos and Mountaineer and assumes APCo operates these facilities at an annual 69% capacity factor through 2040. The model was set up to add the same new resource portfolio as APCo's RPS Portfolio 1 ("WVPSC Preferred");

(1b) a sensitivity to scenario (1a) that incorporates a coal price that is 2% to 12% higher than scenario (1a) ("WVPSC Preferred, high coal price sensitivity");

(2) a scenario that includes ELG investments at Amos and Mountaineer and is set up the same way as scenario (1a), but assumes APCo operates Amos and Mountaineer economically through 2040 ("APCo Preferred");

(3) a scenario that operates Amos and Mountaineer economically until December 31, 2028, then removes them from APCo's Virginia rate base. APCo then meets Virginia's system needs with a combination of solar PV, wind, battery storage, and market purchases based on what the model selected as optimal. After this first stage of modeling, this scenario was re-run with the full capacity of Amos and Mountaineer while locking in the same builds from the first stage to represent a future where West Virginia customers take 100% ownership of Amos and Mountaineer in 2029 and run them at a 69% capacity factor, while Virginia customers' energy and capacity needs are met with alternatives. ("Full Coal Removal"); and

(4) a scenario that uses the same two-step process as scenario (3), except that it removes only Amos from APCo's Virginia rate base on December 31, 2028. This scenario also assumes Mountaineer operates at an annual 69% capacity factor through 2040 ("Partial Coal Removal").[449]

Ms. Kwok conducted the above modeling first using APCo's capacity price forecast, then using a lower price capacity curve (shown above in the discussion of APCo's economic analysis). Finally, Ms. Kwok added to her lower capacity price results a $45/MWh penalty to scenarios that do not comply with the VCEA's mandatory RPS.

[449] *Id.* at 3-4, 12-15, 20.

The results of Ms. Kwok's analysis are summarized in the table below.[450]

Scenario	Modeling with APCo's capacity price	Modeling with lower capacity price	Modeling with lower capacity price and $45/MWh REC shortage penalty
(2) APCo Preferred (no 69% capacity factor)	$5,585	$5,743	$5,896
(3) Full Coal Removal (Amos and Mountaineer)	$6,030	$5,927	$5,927
(4) Partial Coal Removal (Amos only)	$5,720	$5,713	$5,713
(1a) WVPSC Preferred (69% capacity factor)	$5,757	$5,915	$6,068
(1b) WVPSC Preferred, high coal price	$5,931	$6,089	$6,242

Using APCo's capacity price forecast (column of figures on the left), her APCo Preferred Scenario has the lowest NPV revenue requirement, followed by her scenario in which Amos is removed in 2029. Although these results show removing both Amos and Mountaineer did not result in net savings, she stressed that this modeling assumed an unrealistically high capacity price forecast and conservative assumptions, including no future carbon pricing on coal generation during the next eighteen years.[451] She also indicated there are risks associated with higher fuel prices, some of which she quantified in her high coal price sensitivity.[452]

Using her lower price capacity curve (middle column of figures), her scenario in which Amos is removed in 2029 has the lowest NPV revenue requirement, followed closely by the APCo Preferred Scenario. Ms. Kwok believes the Commission should use the WVPSC Preferred Scenario, rather than the APCo Preferred Scenario, as the baseline for comparison to other scenarios since she views the 69% capacity factor as a mandate of the WVPSC by which APCo must abide.[453] Ms. Kwok acknowledged that these results – without consideration of other factors – indicate that leaving Mountaineer in service is $214 million more economic than removing both Amos and Mountaineer.[454] Ms. Kwok recognized the $45/MWh penalty amount (incorporated in the column of figures on the right) reflects the upper bound of the potential risk of RPS non-compliance.[455]

APCo challenged several of the assumptions in Ms. Kwok's analysis. As an overarching concern, APCo witness Martin asserted that every aspect of Ms. Kwok's analysis is undermined by an inaccurate premise that APCo, which is an FRR entity, can purchase capacity in PJM's

[450] *Id.* at 22, 23, 27.
[451] *Id.* at 24.
[452] Tr. at 159, 201-202 (Kwok).
[453] Tr. at 158-59 (Kwok).
[454] Tr. at 189 (Kwok) (discussing, in the context of another table, the difference between the $5.927 billion and $5.713 billion amounts that are also shown in the middle and right columns of the table above).
[455] Ex. 23 (Kwok) at 27.

auctions.[456] He described obtaining capacity through year-to-year bilateral contracts as an unrealistic option.[457]

Mr. Martin believes Ms. Kwok's APCo Preferred Scenario is her only scenario that is not unduly influenced by understated replacement resource costs or uneconomic dispatch, because Amos and Mountaineer will run through 2040.[458] He testified that the assumption that Amos and Mountaineer would run at a 69% capacity factor even if uneconomic is unrealistic and overstates costs.[459] He does not consider this scenario worthy of much consideration given APCo witness Beam's testimony.[460] However, Mr. Martin added that the reduction in energy margins due to uneconomic dispatch for Amos and Mountaineer would need to be eight times larger than projected by Sierra Club to offset the capacity cost savings APCo calculated for the Company's Cases 1 and 2.[461]

Mr. Martin explained that the primary resource Ms. Kwok added to replace Amos and Mountaineer is PJM market capacity, at an assumed short-term capacity price. He reiterated that APCo cannot currently purchase capacity in PJM's auction and thus is effectively assumed to participate in "an uncertain and risky perpetual cycle of seeking year-to-year bilateral capacity contracts."[462] Mr. Martin also believes APCo's customers would be exposed to far too much additional energy market exposure under Sierra Club's resource plan. He provided the data shown in the table below to illustrate the reliance on bilateral capacity contracts, which do not entitle to Company to any energy.[463]

Virginia Jurisdictional Net Market Energy Purchases/ (Sales)	2029-2040 Total Net GWh Purchases/(Sales)	2029-2040 Total ($000)	Change from 2040 Retirements ($000)
APCo Preferred – 2040 Retirements	(10,472)	($679,809)	
2028 Both Removal	83,647	$2,706,447	$3,386,256
2028 Amos Removal	36,192	$1,038,363	$1,718,172

As shown above, going from Sierra Club's APCo Preferred Scenario to the scenario removing both Amos and Mountaineer changes APCo from a net seller of energy with nearly $680 million of Virginia jurisdictional net market sales revenue to a net purchaser of $2.7 billion of energy for its Virginia customers. APCo is a net purchaser of $1.0 billion for its Virginia customers in Sierra Club's scenario where only Amos is removed in 2028. He concluded that "placing this much risk on Virginia customers by using a resource plan with capacity-only contracts (with

[456] Ex. 34 (Martin rebuttal) at 2-3; Tr. at 273, 289 (Martin).
[457] Ex. 34 (Martin rebuttal) at 3.
[458] *Id.* at 12.
[459] *Id.* at 11.
[460] *Id.* at 10-11. However, he noted that Sierra Club's workpapers for Scenario 1a show Amos and Mountaineer remain profitable over the forecast period, just less profitable compared to Scenario 2. *Id.* at 11. Mr. Martin acknowledged uneconomic dispatch would also incur costs other than fuel costs. Tr. at 284-85 (Martin).
[461] Ex. 34 (Martin rebuttal) at 11.
[462] *Id.* at 13.
[463] *Id.* at 15-16.

fossil-fueled resources) is not remotely prudent, even if it were in any way possible, for the Company to do."[464]

Regarding Ms. Kwok's RPS non-compliance costs, Mr. Martin testified that her analysis overstates the impact of the REC deficiencies in APCo's modeling. He testified that, among other things, APCo believes RECs will be available in publicly traded markets and does not anticipate being subject to the $45/MWh deficiency payment.[465]

Notwithstanding the assumptions Mr. Martin challenged, he pointed out that the results of Ms. Kwok's modeling using a lower capacity price forecast show that removing both Amos and Mountaineer will be more expensive than continuing to use them to serve Virginia.[466] He pointed out that because her scenario removing only Amos is less expensive than her scenario removing both Amos and Mountaineer, this indicates that keeping Mountaineer will save customers money. He believes Ms. Kwok's scenario removing only Amos shows tiny savings that are "hardly enough to justify walking away from [Amos] and putting the enormous risks associated with replacing it on the Company and its Virginia customers."[467] APCo pointed out that the savings shown would be less if updated to reflect the Company's more recent ELG cost estimates provided during the hearing.[468]

Hearing Examiner's Conclusions

As discussed above, I agree with some of the observations of Consumer Counsel and Sierra Club about the quantity of "replacement" capacity needed if Virginia does not fund ELG investment. APCo's analysis assumes the Company would push its reserve margin in these scenarios well above what the Company testified is appropriate. Additionally, the economic divide between the scenarios in which APCo contributes to ELG investment and the alternative scenarios is only as wide as presented by APCo[469] if it is assumed that Virginia would continue paying for Amos and Mountaineer's plant-in-service, regardless of ELG investment. Were Amos and Mountaineer to be retired in 2029,[470] then I would agree with APCo that Virginia would be responsible for paying its share of any net book value remaining at retirement under traditional ratemaking.[471] But Amos and Mountaineer are not retiring in 2029, regardless of the Commission's decision in this case, and so this net book value is simply undepreciated plant that remains in service.[472] Accordingly, I cannot reconcile APCo's tandem assumptions that if Virginia does not fund ELG investment: (1) Virginia would receive 0% of the capacity or energy from Amos and Mountaineer as of 2029; but (2) Virginia would still pay an allocated

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[464] *Id.* at 16.
[465] *Id.* at 23-24.
[466] At the hearing, Ms. Kwok revised the $163 million difference referenced by Mr. Martin to $184 million. Tr. at 148. *See, e.g.*, Ex. 23 (Kwok) at 7, 22 (difference in NPVs between Ms. Kwok's "APCo Preferred" and "Full Coal Removal from Rate Base" Scenarios).
[467] Ex. 34 (Martin rebuttal) at 12.
[468] APCo's Brief at 9.
[469] This includes the Staff-modified results.
[470] *See* Ex. 12 (APCo responses to Consumer Counsel discovery requests nos. 1-04 and 1-05) (identifying APCo's opinion that ELG denial by Virginia would be analogous to a plant retirement from a Virginia perspective).
[471] Ex. 11 (Beam direct) at 8.
[472] Tr. at 58 (Castle).

share of the net book value that remains as of 2029. Should Amos and/or Mountaineer remain in service, the assumption that Virginians would continue to pay for that plant to be used exclusively for service to West Virginia[473] is a ratemaking leap in my view. As summarized by Consumer Counsel, "[a] future where Virginia customers are asked to pay up to approximately $500 million for generation facilities that will be in operation, but then are denied any capacity value is neither fair nor in line with traditional utility ratemaking practices."[474]

To be clear, my discussion of this analytical issue is in no way critical of the WVPSC. One of the WVPSC orders approving ELG investment states a clear expectation that if Virginia does not fund ELG investment then West Virginia could get 100% of the capacity or energy.[475] That finding was based in part on testimony APCo provided to the WVPSC that this would be a fair result.[476] As discussed above, my concern about APCo's assumption in the instant case of a 0% Virginia benefit (consistent with a WVPSC order) is that it is made in conjunction with APCo's assumption that Virginia would continue to pay for plant-in-service in future years (*not* in a WVPSC order). There is an analytical asymmetry. If the analysis assumes – consistent with APCo's position and the WVPSC order – that it is a fair result for West Virginia to get 100% of the capacity and energy from Amos and Mountaineer beginning in 2029, then the results of APCo's Cases 1, 2, and 3, should be reduced by an approximate Virginia share of the estimated $1.05 billion net book value as of December 31, 2028 (which Consumer Counsel reasonably ballparks as $500 million).[477] This adjustment would also address my concern about the amount of "replacement" capacity used in Cases 1, 2, and 3, because while the current FRR rules may view APCo as a whole, I have no illusion that such a rule would be sustainable if Virginia were not to fund ELG investment (the assumption in these Cases) and Virginia were to maintain no responsibility for any remaining net book value. That FERC petition might write itself. Since my view of interjurisdictional equity in these analyses is a two-way street, it is reasonable to assume that any legal or equitable claim Virginia has to the Amos and Mountaineer capacity ceases if and when – as a net book value adjustment to APCo's results necessarily assumes – Virginia stops paying for these facilities' undepreciated plant-in-service.

Turning back to the results of APCo's economic analysis, after recognizing Staff's modifications and a $500 million Virginia net book value estimate as of December 31, 2028, APCo's results, as adjusted, indicate that ELG investment in Amos and Mountaineer is more economic by $866 million (Case 1), $1.22 billion (Case 2), and $281 million (Case 3). Like APCo's economic analysis, Sierra Club's analysis reflects no net book value benefit to scenarios in which it is assumed that APCo receives zero capacity or energy benefit from Amos or Mountaineer as of January 1, 2029. Adjusting Sierra Club's modeling results to reflect a $500 million benefit where both Amos and Mountaineer are removed and a $275 million benefit

[473] In this scenario, all of the Amos and Mountaineer plant-in-service would be useful only to West Virginia.
[474] Consumer Counsel's Brief at 5.
[475] Ex. 18 at 7-10.
[476] *Id.* at 8-9. This order also indicates that the *2021 E-RAC Order* effectively ordered that APCo retire Amos and Mountaineer by 2028. *Id.* at 8. I note that Virginia law does not require APCo to get pre-approval of any environmental compliance projects or costs and that the *2021 E-RAC Order* denied APCo's proposal without prejudice.
[477] The date of the estimated net book value aligns with the use of 2029 for the NPV economic results in this case.

where only Amos is removed,[478] changes the order of Sierra Club's results. For Sierra Club witness Kwok's modeling using APCo's capacity price, her scenario in which Amos is removed and her scenario in which both Amos and Mountaineer are removed become more economic than the APCo Preferred Scenario by $140 million and $55 million, respectively.[479] For her results using a lower capacity price, her scenario removing Amos and Mountaineer and her scenario removing only Amos become more economic than the APCo Preferred Scenario by amounts ranging between $305 million and $469 million.[480]

I have given less weight to Sierra Club's scenarios that effectively penalize Virginia for an uneconomic regulatory dispatch of Amos or Mountaineer. I agree that the potential risk to Virginia associated with a mandatory regulatory dispatch of Amos and Mountaineer by the WVPSC should be among the risks considered by the Commission. While APCo asserted that there is no 69% mandate,[481] and several parts of the WVPSC's orders tend to support APCo's position that this is a ratemaking issue, other parts of the WVPSC's orders seem to suggest otherwise.[482] In my view, the sworn testimony of Mr. Beam, APCo's President, mitigates the uneconomic dispatch risk identified by Sierra Club – namely, that Virginia jurisdictional customers might bear higher costs associated with a regulatory dispatch requirement. Mr. Beam testified that APCo would not seek from Virginia the costs of any uneconomic regulatory dispatch, if mandated by WVPSC.[483] I recommend this commitment – and the Commission's ability to implement it, if necessary, through rate ring-fencing – be made a condition of any approval in this case.

I agree with Sierra Club that calculating the costs associated with the uneconomic dispatch of Amos and Mountaineer could be complicated and burdensome.[484] Such calculations may require a comparison against a hypothetical economic dispatch, and the variable costs of Amos and Mountaineer are not neatly contained in one rate mechanism. However, the Commission's decision in the instant case would not determine whether the Commission must undertake this complicated analysis unless the 69% capacity factor (1) is an operational requirement, and (2) is limited to post-2028 operations. While APCo has sought clarification on whether the 69% capacity factor is an operational requirement, I see nothing in the relevant WVPSC orders suggesting that the 69% capacity factor – whether it is an operational requirement or only a West Virginia ratemaking consideration – is relevant only after 2028. Indeed, the WVPSC incorporated an assumed 69% capacity factor in APCo's West Virginia

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[478] $275 million is 55% of $500 million. The net book value figures provided by APCo show that Amos's projected net book value is 55% of the total net book value estimated for these plants as of December 31, 2028.

[479] In the order in which they are mentioned in this sentence, the cost of her referenced scenarios would be $5.445 billion, $5.530 billion, and $5.585 billion.

[480] In the order in which they are mentioned in this sentence, the cost of her referenced scenarios would be $5.427 billion, $5.438 billion, and $5.743 billion (without the $45/MWh penalty) or $5.896 billion (with the penalty).

[481] APCo's Brief at 10-11.

[482] *See, e.g.*, Ex. 21 at 4 ("The Commission recognized the excessive cost of relying on the PJM energy market in September 2021 *when we ordered the Companies to increase self-generation* in lieu of the PJM market and high cost purchased power contracts.") and 7 (finding APCo and Wheeling Power Company "have not achieved 69 percent capacity [sic] at their coal-fired generating plants *as ordered by the [WVPSC].*") (emphasis added).

[483] Tr. at 268 (Beam).

[484] Tr. at 154-57 (Kwok). *See also* Tr. at 255 (Beam) (testifying that APCo, while waiting on its pending request for clarification from the WVPSC, has not put forward a plan for identifying uneconomic dispatch costs).

rates approved last year.[485] How to address a WVPSC regulatory dispatch of Amos and/or Mountaineer would become a Virginia ratemaking issue if and when such dispatch occurs.

In sum, based on the scenarios I have given the most weight, APCo's and Sierra Club's economic analyses, after incorporating Staff's adjustments and a net book value adjustment, indicate a NPV benefit of Virginia investment in ELG for both Amos and Mountaineer ranging from positive $1.2 billion to negative $470 million, approximately. Sierra Club's scenario establishing the low end of this range is heavily reliant on the energy and capacity market, and with APCo assumed to secure a 14.9% reserve margin exactly. I also note that if the Commission does not agree there is an analytical asymmetry warranting a net book value adjustment, then all of Sierra Club's results indicate it would cost more to remove both Amos and Mountaineer, rather than retain them both, except in scenarios where Virginia ratepayers are penalized for an assumed 69% regulatory dispatch.[486] At the hearing, APCo provided updated ELG cost estimates of $21 million (Mountaineer) and $63.5 million (Amos), which are lower than what was incorporated in the economic analyses discussed above. These updated estimates would favorably impact the ELG investment scenarios to some extent.

APCo's and Sierra Club's results also do not capture all of the risks associated with a decision to invest, or not invest, in ELG compliance. APCo, Sierra Club, and the Coal Association identified several risks (in addition to 69% regulatory dispatch) for the Commission to consider, many of which are competing. Sierra Club highlighted, for example, additional coal price risk, the potential for additional regulation, and the risk of foregoing resources made less expensive by the Inflation Reduction Act.[487] Sierra Club witness Kwok believes such risks likely make ELG investment imprudent.[488] APCo, on the other hand, highlighted the risks associated with increased market exposure and new resource development.[489] APCo described approval of ELG investment as approval of a reasonably priced insurance policy, in essence, against such risks.[490] The Coal Association urged the Commission to consider persistent supply chain disruptions, the war in Ukraine, and concerns about the recent substantial increase in natural gas prices and volatility.[491] The Coal Association also believes ELG investment would provide time "to gain greater clarity on which new resources should be pursued."[492]

While the Commission may assign different weight to the record evidence on the various economic results and relevant risks identified in the record, based on my assessment of the record, I find that the record supports an approximately $21 million ELG investment at Mountaineer, and, to a lesser extent, an approximately $63.5 million ELG investment at Amos,

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[485] *See, e.g.*, Ex. 19 at 6 ("At this time, however, we will use a capacity factor of 69 percent for the Companies' projected ENEC costs."); Ex. 20 at Appendix A.
[486] Ex. 23 (Kwok) at 22, 23, 27.
[487] *See, e.g.*, Ex. 23 (Kwok) at 41; Tr. at 159-60 (Kwok). While Ms. Kwok focused on tax credits available for renewables and storage, Coal Association witness Medine identified increased tax credits for carbon capture and sequestration. Ex. 1 (Medine) at 6.
[488] Ex. 23 (Kwok) at 6-7, 41-42.
[489] *See, e.g.*, Ex. 34 (Martin rebuttal) at 16-21.
[490] Tr. at 18 (Coates).
[491] Ex. 1 (Medine) at 14-18. Similar to APCo, Ms. Medine sees ELG investment in Amos and Mountaineer "as a hedge against market volatility" and "and insurance against supply chain issues." *Id.* at 19.
[492] *Id.* at 19-20.

subject to the condition that APCo not seek from Virginia any costs of uneconomic regulatory dispatch (if required by the WVPSC) and the Commission's ability to implement this commitment through rate ring-fencing. After adjusting APCo's results as discussed above, the Company's economic analysis, showing estimated NPV benefits reaching as high as $1.2 billion, establishes a substantial likelihood that ELG investment would benefit Virginia ratepayers at a reasonable cost in my opinion. A number of conditions currently affecting the energy industry – including the recent run-up in natural gas prices,[493] supply-chain challenges, and the backlogged PJM queue[494] – seem to caution against a decision at this time to move away from significant existing sources of capacity and energy. Amos and Mountaineer provide a significant amount of capacity and, assuming uneconomic regulatory dispatch costs do not appear, provide a hedge against energy market prices and volatility. Based on my assessment discussed above, Sierra Club's modeling offers the prospect of $470 million (NPV) of savings during the next decade. This amount that would be somewhat lower assuming a reserve margin above a 14.9% minimum and/or assuming RECs can be obtained at prices lower than the statutory non-compliance penalty amount, and this amount would disappear if the Commission disagrees with my net book value adjustment. Importantly, the modeled scenario indicating the potential for such benefits carries an appetite for market risk that is much higher than scenarios in which Virginia continues to share the costs and benefits of Amos and Mountaineer beyond 2028.[495] Shifting APCo from a self-sufficient utility accessing the wholesale market when beneficial for Virginia ratepayers to one that significantly relies on the market to serve Virginia would be notable. Given PJM's relatively low penetration of renewables[496] and the effect high natural gas prices (like recent levels) can have on the energy market, Sierra Club's modeling places a bigger bet on the market than I recommend, although the Commission could assign different weight to the relative risks and the economic analyses than I have.

In addition, APCo should be able to address the risk of foregoing resources made less expensive by the Inflation Reduction Act through the Company's ongoing VCEA compliance process. If future RFPs do produce low-cost renewable and/or storage options, a more aggressive approach to compliance could be warranted. The extended tax benefits of the Inflation Reduction Act last through 2032, followed by a potential extension and/or three-year phase out.[497] In other words, even if it is not economically prudent for Virginia to pivot from one or all of the Amos units as soon as 2029, the remainder of this decade may provide greater clarity on whether and when doing so during the next decade would be prudent. Maintaining Amos's current depreciation rates (with assumed retirement dates of 2032/2033) for Virginia ratemaking purposes may provide APCo with additional flexibility to pursue, and absorb in rates, replacement resources for one or more of Amos's units in 2032, for example, should such action be in the best interests of Virginia in the future.[498]

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[493] *See, e.g., id.* at 13.
[494] Ex. 11 (Beam direct) at 8-9.
[495] *See, e.g.,* Ex. 34 (Martin rebuttal) at 15-16.
[496] *See, e.g.,* Ex. 11 (Beam direct) at 7.
[497] *See, e.g.,* Tr. at 200-01 (Kwok). *See also* Public Law 117-169, Sections 13701 and 13702. The potential for an extension beyond 2032 would be triggered if annual greenhouse gas emissions from domestic electricity production are not at least 75% lower than in calendar year 2022. *Id.* at Section 13701.
[498] In 2035, APCo expects that the total UCAP provided by the renewable resources APCo plans for VCEA compliance will reach the amount of capacity needed to offset one Amos unit. Ex. 11 (Beam direct) at 6.

However, I note that APCo was directed to provide a comprehensive retirement analysis of Amos and Mountaineer in its 2022 IRP filing, which the Commission will consider at a hearing next week.[499] As the records developed in the IRP and the E-RAC cases will be concurrently before the Commission, the Commission will have the benefit of a broader set of economic analysis than the record evidence on which my analysis must rely.

Should the Commission not adopt my findings and recommendations based on the record in this E-RAC case or the IRP case, much of the record evidence in this E-RAC case indicates that between Amos and Mountaineer, investment in ELG at Mountaineer is likely a more economic option than at Amos. Sierra Club's modeling results indicate that maintaining Mountaineer is lower cost than removing both Amos and Mountaineer.[500] The ELG investment in Mountaineer is lower cost (both on a dollars and dollars-per-MW basis) than ELG investment in Amos.[501] Mountaineer has also been dispatched with generally higher capacity factors than Amos in recent years. These historically higher capacity factors (including 71% in 2019, just prior to the pandemic[502]) and Mountaineer's smaller size, compared to Amos, indicate that the risk associated with quantifying any uneconomic regulatory dispatch of Mountaineer would be less than any such risk associated with Amos.[503]

If Virginia does not fund ELG, APCo characterized the remaining net book value attributable to Virginia on December 31, 2028, as a potential "stranded cost" that APCo cannot force onto West Virginia.[504] APCo is concerned that cost recovery of the Virginia share of net book value under this scenario could effectively become stuck between two jurisdictions.[505] If so, given APCo's testimony to the WVPSC, the Company should give more thought to an intracompany arrangement that is fair to all of its customers, in Virginia and West Virginia. Consumer Counsel has identified one approach – matching energy and capacity with proportional investment[506] – that may be worthy of exploration. As suggested by Consumer Counsel:

> The West Virginia jurisdiction cannot claim all of the capacity revenue for a generation facility for which Virginia customers continue to pay. A more equitable result, which would be subject to future Commission approval, would be for the West Virginia and Virginia jurisdictions to share the capacity revenues in a proportion that recognizes each jurisdiction's relative cost responsibility for all of the fixed costs of [Amos and Mountaineer]. In this manner, each jurisdiction would be allocated a fair

[499] Ex. 30 (Morris) at 18-19.
[500] Ex. 23 (Kwok) at 22, 23, 27; Tr. at 189 (Kwok).
[501] $42 million/1,305 MW = $32,183/MW; $127 million/2,930 MW = $43,345/MW.
[502] Ex. 23 (Kwok) at attached Ex. SK-11.
[503] Mountaineer's smaller size also indicates that, compared to Amos as a whole, Mountaineer is less of a hedge against some of the market risks discussed above.
[504] Tr. at 58-59 (Castle); Tr. at 98-99 (Beam).
[505] Tr. at 59 (Castle).
[506] Another potential approach, if such costs are properly classified as "stranded costs," might be for the Commission to evaluate the proposal to recover any such plant costs by assessing any ongoing stranded cost recoveries of the underlying plant costs through wholesale and/or retail revenues.

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> approximation of the [p]lants' capacity value, while minimizing subsidies for the public policy choices of the other.[507]

Some variation of this approach, if feasible, could seemingly be used to recognize, for example, any relatively higher investment in coal resources made by West Virginia (if Virginia denies ELG investment) and any relatively higher investment in renewables and storage made by Virginia.

II. ANALYSIS OF DRY SORBENT INJECTION RECONFIGURATION

The Amos Units 1 & 2 dry sorbent injection project would reconfigure the existing injection system to handle hydrated lime, rather than trona. According to the Company, switching to hydrated lime would reduce issues related to corrosion, improve heat rate, improve equivalent unplanned outage rate, lower minimum load, and help with the long-term protection of the SCR catalyst, air heaters, and precipitators.[508] The system is scheduled to be retrofitted during outages this fall.[509]

APCo acknowledged that this reconfiguration is not necessary for compliance with any specific environmental regulation. Rather, this project will allow for *more economic* compliance with an environmental regulation that required construction of the original dry sorbent injection system.[510]

Based on the nature of this project, Sierra Club found these costs "unfit for inclusion" under Code § 56-585.1 A 5 e.[511] Consumer Counsel questioned whether the project might be eligible for recovery through the Company's generation base rates if justified as reasonable and prudent, which Consumer Counsel did not contest.[512]

Based on the record, I find that APCo did not establish that the dry sorbent injection reconfiguration, and associated costs, are necessary to comply with state or federal environmental laws or regulations. I agree with Consumer Counsel that such a finding, if adopted by the Commission, should not preclude the Company from seeking cost recovery of this project through base rates. If, as APCo indicates, this project will lower overall costs for Virginia customers[513] the project should go forward, just with cost recovery requested through the appropriate rates. The estimated cost of this project is $9.4 million, with a proposed revenue requirement of approximately $621,000 in this case.[514]

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[507] Consumer Counsel's Brief at 7-8.
[508] Ex. 8 (Sherrick direct) at 12.
[509] *Id.* at 13.
[510] Tr. at 74-76 (Spitznogle); APCo's Brief at 20.
[511] Sierra Club's Brief at 19. Sierra Club argued that these costs should also be denied on the alternative ground that APCo did not analyze whether this project is reasonable if Amos were to retire in 2028. *Id.* at 19-20.
[512] Consumer Counsel's Brief at 16.
[513] APCo's Brief at 20.
[514] Ex. 31 (Morgan) at 3; Ex. 8 (Sherrick direct) at 12.

III. ANALYSIS OF RGGI ALLOWANCE COSTS

As a result of Virginia joining RGGI in 2021, APCo must now purchase one RGGI allowance for every ton of CO_2 generated by Clinch River. These RGGI compliance costs are required because Clinch River is located in Virginia.[515]

APCo deferred approximately $341,000 of Virginia jurisdictional RGGI allowance costs through December 31, 2021.[516] APCo's proposed E-RAC includes this amount, in addition to forecasted RGGI expense of approximately $458,000 through November 2023.[517] If actual RGGI allowance costs are less than forecasted RGGI allowance costs, APCo will record the difference and include it in a future E-RAC petition.[518]

APCo witness Martin sponsored discovery responses about the self-scheduling of Clinch River that were admitted into the record. The responses indicate that APCo does not document the reason for self-scheduling Clinch River because it would be administratively burdensome to maintain records on an hourly basis given the relative infrequency of self-scheduling this plant. However, the responses also indicate that the typical reasons for self-scheduling Clinch River are related to required environmental and capacity testing.[519] The responses also identified all days and hours in 2021 when either of the units at Clinch River was self-scheduled.[520] At the hearing, Mr. Martin indicated the self-scheduled, or must-run, status was for the economic minimum of a given unit and not the entire capacity of the unit.[521] Assuming separate figures provided in discovery identify the hours in 2021 when Clinch River was economically dispatched, the document identifying all the self-scheduled hours in 2021 indicates that Clinch River Units 1 and 2 were self-scheduled (at least in part) for 32% and 24% of the respective hours they were dispatched during 2021.[522] APCo witness Martin testified that these percentages would be much smaller if they were weighted by the amount of generation that was self-scheduled.[523]

Appalachian Voices recommended that the Commission deny, without prejudice, APCo's proposed recovery of its actual and forecasted RGGI compliance costs. Appalachian Voices argued APCo has not established that its proposed RGGI compliance costs are "necessary," with Appalachian Voices asserting that APCo's conduct supports equating "necessary" to "least cost."[524] Appalachian Voices argued further that "while a RGGI cost might be 'reasonable and prudent,' it is not recoverable under an A 5 e RAC unless it is separately proven to be 'necessary.'"[525] According to Appalachian Voices, APCo failed to carry "its burden of proving that the entirety of RGGI compliance costs are necessary."[526] In support of its recommended

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[515] *See, e.g.*, Ex. 9 (Spitznogle direct) at 16.
[516] Ex. 10 (Ross direct) at 7.
[517] *Id.* at 8.
[518] Tr. at 83-84 (Ross)
[519] Ex. 14 (APCo's response to Appalachian Voices' discovery request no. 2-04).
[520] Exs. 15C, 16.
[521] Tr. at 125-26 (Martin).
[522] Exs. 15C, 16; Tr. at 127-31 (Martin).
[523] Tr. at 130 (Martin).
[524] Appalachian Voices' Brief at 13.
[525] *Id.* at 5.
[526] *Id.* at 2.

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denial of RGGI costs, Appalachian Voices focused on the instances in which Clinch River self-scheduled in 2021;[527] Appalachian Voices' legal interpretation of the word "necessary";[528] and insufficient clarity on how the proposed RGGI costs were calculated.[529]

I agree that costs can be reasonable and prudent, but not necessary for environmental compliance. The costs of the dry sorbent injection project (discussed in Section II of this Report's Analysis) fit that category, for example. But I am not convinced that the word "necessary" in Code § 56-585.1 A 5 e is as expansive or complicated as Appalachian Voices suggests. For the RGGI costs at issue, environmental compliance requires APCo to purchase one RGGI allowance for every ton of carbon generated by Clinch River. Additionally, to the extent APCo incurs allowance costs associated with testing environmental equipment to maintain its air permits,[530] these costs may be necessary to comply with multiple environmental laws and regulations.

However, I find that the self-scheduling issue raised by Appalachian Voices is relevant to the Commission's consideration of whether the proposed costs are reasonable and prudently incurred. In my view, Appalachian Voices could have a colorable claim about the prudence of allowance costs incurred during self-scheduled dispatch – depending on the circumstances of such dispatch in 2021. The circumstances of self-scheduled dispatch identified by APCo, environmental testing and capacity testing, are unquestionable. Because of the potential economic and reliability consequences, testing is prudent and can be required. However, the record was not definitive on whether APCo identified the *typical* reasons or the *only* reasons for self-scheduling during 2021. In discovery, APCo indicated testing was the typical reason[531] while at the hearing APCo witness Beam indicated that he understood this to be the only reason based on a communication between him and a co-worker the day of the hearing.[532] I do not doubt the veracity of Mr. Beam's testimony, but it was based on second-hand information incapable of scrutiny at the hearing.[533] The evidentiary concern is not one of credibility, rather it is one of reliability. Accordingly, I recommend that a percentage of the actual RGGI allowance costs proposed for recovery in this case be denied without prejudice. The record does not contain precise information on the dollars at issue because the number of hours of self-scheduling, which is in the record, does not equate to the amount of energy production and associated tons of CO_2.[534] APCo suggested that the amount at issue might be approximately $7,000 to $14,000,[535] while the absolute high-end would be approximately $95,000.[536] Provided any such denial by the Commission is without prejudice, as requested by Appalachian Voices and recommended herein, any figure within this range would be reasonable for purposes of the

[527] *Id.* at 5-12.
[528] *Id.* at 12-14.
[529] *Id.* at 14-17.
[530] *See, e.g.,* Tr. at 257 (Beam); Ex. 14 (APCo's response to Appalachian Voices' discovery request no. 2-04).
[531] Ex. 14 (APCo's response to Appalachian Voices' discovery request no. 2-04).
[532] Tr. at 242, 258-61 (Beam).
[533] *See, e.g.,* Appalachian Voices' Brief at 10-11.
[534] Tr. at 125-26, 129-30 (Martin).
[535] Tr. at 130 (Martin). $341,000 x 2% = $6,820. $341,000 x 4%= $13,640.
[536] While the 2021 self-schedule hours are for each of the two Clinch River units, the allowance price data does not distinguish between the two units. $341,000 x 28% (average of two units self-schedule hours) = $95,480.

instant case. Based on APCo's energy billing determinants,[537] I am not certain that even a $95,000 amount would affect the proposed rates.

I do not recommend denial of any of the forecasted RGGI allowance costs. No case participant questioned the quantity (tons) APCo used to calculate the projected costs, as shown in the Petition.[538] I find these projected volumes – which are noticeably lower than the actual volumes in 2021 but generally align in the same time of year as 2021 volumes – are consistent with a peak facility that runs infrequently and primarily during the summer.[539] Nor did any case participant question the forecasted prices identified in the Petition, which appear consistent with RGGI auction prices.[540] Because I find the RGGI allowance cost calculation in the Petition clear, I disagree with the assertion of Appalachian Voices that APCo offered little to no information about how the proposed RGGI costs were calculated.[541]

Where the record took a slight detour was on an issue raised at the hearing by counsel for Appalachian Voices as to whether there are some wholesale revenues that could potentially be credited in Code § 56-585.1 A 5 e against the RGGI allowance costs.[542] Ultimately, I believe the record indicated that unless there are off-system sales – the net margins of which are credited through the fuel factor, as directed by Code § 56-249.6 – the wholesale revenues APCo receives as a generator offset the wholesale costs it is charged as a load-serving entity.[543] If so, there do not appear to be any wholesale revenues that are unaccounted for at retail.[544] Where revenues can or should be credited in retail rates would appear to be a policy or a legal question for the Commission, rather than a potential shortcoming of APCo in meeting its evidentiary burden in the instant case.[545] Accordingly, I do not view this issue as grounds for denial of the proposed RGGI costs. Additionally, based on the record, I do not see any revenues that could reasonably be matched against the cost of allowances recoverable from APCo's customers under Code § 56-585.1 A 5 e, but nothing would prevent Appalachian Voices from attempting to develop a better record on this issue in a future proceeding.[546]

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[537] Ex. 4 (Petition) at Filing Sched. 46, Section 5.

[538] *See* Ex. 4 (Petition) at Filing Sched. 46, Section 4 O&M RGGI (showing, by month, the actual and projected emissions of tons and corresponding allowance prices). These figures are on a total company basis while the amounts provided at the beginning of this section of the Report are provided on the Virginia jurisdictional basis proposed by APCo.

[539] *Id.*

[540] *Id.*

[541] Appalachian Voices' Brief at 14.

[542] *Id.* at 14-16.

[543] *See, e.g.*, Tr. at 301-302 (Morgan). *See also* APCo's Brief at 19-20. Consistent with the positive effect that the economic dispatch of Amos and Mountaineer has on the economic analyses in this case, the offsetting wholesale revenues provided by the dispatch of APCo's generation appear to benefit customers because there would otherwise be a purchase of power from the market (without the corresponding wholesale revenue).

[544] Ex. 14 (APCo's response to Appalachian Voices' discovery request no. 2-02) (identifying that both sales *and* purchased power accounts are used when Clinch River is dispatched by PJM).

[545] Appalachian Voices' Brief at 17.

[546] The record does not indicate that there are any new or increased revenues that RGGI participation created for APCo. However, the RGGI allowances paid for by ratepayers may be considered revenues for the Commonwealth and the governmental entities who receive this money, as specified by the Code. Code § 10.1-1330 C.

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Appalachian Voices also recommended that the Commission:

> • Direct APCo, if it still wishes to recover RGGI costs via the E-RAC, that it must, at a minimum, provide the detailed backward-looking analysis APCo indicated it was capable of providing for its Clinch River units;
>
> o To the extent APCo is able, a backward-looking analysis should also be integrated into the going forward requirements set forth below;
>
> • Direct APCo that for future E-RAC cost recovery for RGGI compliance costs, APCo shall perform a necessary analysis that identifies least cost options and identifies with specificity how the costs it is seeking to recover from customers are necessary; and
>
> • Directs APCo, that going forward, each time it self-schedules Clinch River units, it must record (1) [MWh] and hours of the day that Clinch River units are self-scheduled to must run; (2) in the times that Clinch River units are self-scheduled to must run, record total costs to run the units at the identified level, the portion of those costs that are RGGI compliance costs, whether the RGGI costs were fully compensated for in the identified time period, and any delta that remains (i.e., the actual energy margin).[547]

I recommend that the Commission direct APCo to record the hours of each day that Clinch River self-schedules, the associated MWs, as well as the reason for each self-scheduling. The remaining recommendations appear to be too heavy-handed, in my view, for a power plant that runs as infrequently as Clinch River does. This is one peaking power plant, less than 500 MW, that basically runs a little bit of the time in the summer.[548]

IV. OTHER UNCONTESTED ISSUES

APCo asserted that the E-RAC rates should be incorporated into the balancing charge associated with the non-renewable generation rate adjustment clauses of APCo's Rider WWS. APCo believes Commission guidance confirming its opinion would benefit APCo[549] by

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[547] Appalachian Voices' Brief at 17-18.

[548] *See* Ex. 4 (Petition) at Filing Sched. 46, Section 4 O&M RGGI.

[549] Ex. 7 (Castle direct) at 11. Mr. Castle quoted the following statement from the cited Commission order:

> [T]he Company proposes that Rider WWS participants pay for standard service plus all riders except the fuel factor rider, non-renewable generation rate adjustment clauses, and generation costs in base rates. The Company states that instead, participating customers would pay a "balancing" charge that credits the Company's base rates and these riders in amounts that keep non-participants unaffected by participation.

Application of Appalachian Power Company, For approval of a 100% renewable energy rider pursuant to § 56-577 A 5 of the Code of Virginia, Case No. PUR-2017-00179, Order Approving Tariff at 2 (Jan. 7, 2019).

providing clarity on the appropriate language in the tariff.[550] APCo witness Castle testified that Commission guidance would not affect the amounts charged to Rider WWS participants or non-participants.[551] I find this request reasonable. The costs recovered through the E-RAC are predominantly for environmental compliance at APCo's fossil-fueled generation stations.

Staff recommended the Commission direct APCo to incorporate a depreciation rate analysis of its E-RAC investment in its next depreciation study, including net salvage considerations and any excess/deficient depreciation accruals on such assets through the date of the study.[552] APCo agreed and described its plan to perform such a study in conjunction with the Company's upcoming triennial review filing.[553] I find Staff's recommendation reasonable.

Beyond the issues addressed in Sections I, II, and III, of this Report's Analysis, APCo's proposed costs, cost allocation, and rate design were not challenged. The uncontested costs include the costs of projects previously approved by the Commission under Code § 56-585.1 A 5 e, in addition to APCo's proposed dissolved oxygen project at Claytor.[554] I find these uncontested costs satisfy the applicable requirements of Code §§ 56-585.1 A 5 e and 56-585.1 D.

FINDINGS AND RECOMMENDATIONS

Based on the Code and the record developed in this proceeding, I find that:

(1) The results of APCo's ELG economic analysis should be adjusted to incorporate Staff's modifications reflecting: (i) an energy margin for Amos and Mountaineer; and (ii) unforced capacity in Case 3;

(2) The results of APCo's and Sierra Club's ELG economic analyses should be adjusted by an estimate of the Virginia share of Amos and Mountaineer's net book value as of December 31, 2028, to reflect the analytical asymmetry in assuming that, if Virginia does not make an ELG investment in Amos and Mountaineer: (i) Virginia customers would receive zero benefit from Amos and Mountaineer beyond 2028; but (ii) Virginia customers would nonetheless continue to pay for Amos and Mountaineer plant-in-service being used exclusively to serve West Virginia;

(3) Based on the scenarios I have given the most weight, APCo's and Sierra Club's economic analyses, after incorporating Staff's adjustments and a net book value adjustment, indicate a net present value benefit of Virginia investment in ELG for both Amos and Mountaineer ranging from positive $1.2 billion to negative $470 million, approximately;

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[550] Tr. at 57 (Castle).
[551] Tr. at 56-57 (Castle).
[552] Mr. Morgan indicated APCo's next study should be based on depreciable plant balances as of a date no later than December 31, 2024. Ex. 31 (Morgan) at 5, n.3.
[553] Ex. 32 (Ross rebuttal) at 1-2.
[554] *See, e.g.*, Ex. 9 (Spitznogle direct) at 12-14; Ex. 6 (Gallimore direct) at 3-5.

(4) If the Commission does not agree that there is an analytical asymmetry warranting a net book value adjustment, then all of Sierra Club's results indicate it would cost more to remove both Amos and Mountaineer, rather than retain them both, except in scenarios where Virginia ratepayers are penalized for an assumed 69% regulatory dispatch;

(5) The record identifies, for the Commission to consider, various risks associated with either approving or denying ELG investment;

(6) The sworn testimony of Mr. Beam, APCo's President, mitigates the risk that Virginia jurisdictional customers might bear higher costs associated with a mandatory regulatory dispatch of Amos or Mountaineer (if ordered by the WVPSC). Mr. Beam testified that APCo would not seek from Virginia the costs of any uneconomic regulatory dispatch, if mandated by WVPSC;

(7) While the Commission may assign different weight to the record evidence on the various economic results and relevant risks identified in the record, I find that the record supports an approximately $21 million ELG investment in Mountaineer, and, to a lesser extent, an approximately $63.5 million ELG investment in Amos, subject to the condition that APCo not seek from Virginia any costs of uneconomic regulatory dispatch (if required by the WVPSC);

(8) APCo did not establish that its dry sorbent injection reconfiguration for Amos Units 1 and 2, or the associated costs, are necessary to comply with state or federal environmental laws or regulations. However, such costs may be recoverable through base rates;

(9) The prudence of self-scheduling, and associated RGGI costs, could depend on the circumstances. Because the record was unclear on the circumstances of Clinch River's self-scheduling in 2021 APCo did not establish whether approximately $7,000 to $95,000 of RGGI costs were prudently incurred in 2021. APCo has otherwise met its burden of proof for the proposed actual and projected RGGI costs, which would remain subject to true-up in future E-RAC proceedings;

(10) The Commission should direct APCo to record the hours of each day that Clinch River self-schedules, the self-scheduled MWs for each such hour, and the reason for each self-scheduling;

(11) The E-RAC rates, which recover generation costs that are predominantly non-renewable, can be incorporated into the balancing charge associated with the non-renewable generation rate adjustment clauses of APCo's Rider WWS; and

(12) APCo should incorporate a depreciation rate analysis of its E-RAC investment in its next depreciation study, including net salvage considerations and any excess/deficient depreciation accruals on such assets through the date of the study.

Accordingly, **I RECOMMEND** that the Commission enter an order that:

(1) ***APPROVES*** an approximately $21 million ELG investment in Mountaineer, and an approximately $63.5 million ELG investment in Amos, subject to the condition that APCo not seek from Virginia any costs of uneconomic regulatory dispatch (if required by the WVPSC) and the Commission's ability to implement this commitment through rate ring-fencing;

(2) ***DENIES***, without prejudice, the proposed recovery of Amos dry sorbent injection reconfiguration costs;

(3) ***DENIES***, without prejudice, the proposed recovery of approximately $95,000 of 2021 RGGI costs;

(4) ***APPROVES*** a $32,890,000 revenue requirement to revise the E-RAC rates for service to be rendered from December 1, 2022, to November 30, 2023;

(5) ***DIRECTS*** APCo, each time it self-schedules Clinch River, to record the hours of each day that Clinch River self-schedules, the associated megawatts that are self-scheduled, and the reason for each self-scheduling;

(6) ***CLARIFIES*** that the E-RAC rates should be incorporated into the balancing charge associated with the non-renewable generation rate adjustment clauses of APCo's Rider WWS;

(7) ***DIRECTS*** APCo to incorporate a depreciation rate analysis of its E-RAC investment in its next depreciation study, including net salvage considerations and any excess/deficient depreciation accruals on such assets through the date of the study; and

(8) ***DISMISSES*** this case.

COMMENTS

Staff and parties are advised that, pursuant to Rule 5 VAC 5-20-120 C of the Commission's Rules of Practice and Procedure and Code § 12.1-31, any comments on this Report must be filed on or before November 1, 2022. In accordance with the directives of the Commission's *COVID-19 Electronic Service Order*[555] the parties are encouraged to file electronically. If not filed electronically, an original and fifteen (15) copies must be submitted in writing to the Clerk of the Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218. Any party filing such comments shall attach a certificate to the foot of such document certifying that copies have been sent by electronic mail to all counsel of record and any such party not represented by counsel.

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[555] *Commonwealth of Virginia, ex rel State Corporation Commission, Ex Parte: Electronic service among parties during COVID-19 emergency*, Case No. CLK-2020-00007, Doc. Con. Cen. No. 200410009, Order Requiring Electronic Service (Apr. 1, 2020) ("*COVID-19 Electronic Service Order*").

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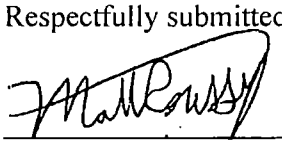
Respectfully submitted,



D. Mathias Roussy, Jr.
Hearing Examiner

Document Control Center is requested to send a copy of the above Report to all persons on the official Service List in this matter. The Service List is available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, Tyler Building, First Floor, Richmond, VA 23219.