Methane Emission Monitoring of Appalachian Compressor Station

Roger Andrew Lataille

Thesis submitted to the faculty of the Virginia Polytechnic Institute and State University in partial fulfillment of the requirements for the degree of

Master of Science

In

Mining Engineering

Nino S. Ripepi, Chair

Emily Sarver

Cheng Chen

06 December 2021

Blacksburg, Virginia

Keywords: natural gas, methane, pipeline, eddy covariance

Methane Emission Monitoring of Appalachian Compressor Station

Roger Andrew Lataille

Abstract

A single compressor station site along a gathering line network was monitored for fugitive methane emissions to quantify long-term emissions in Appalachia Virginia. Continuous monitoring was conducted from January 2021 to April 2021. The compressor station undergoing monitoring operated two CAT3516 Tale and one CAT3516 B engines operating at 80% of max output flow. Data presented on methane emissions during this period was gathered with an eddy covariance monitoring station. This station was equipped with an LI-7700 methane analyzer, LI-7500A - CO_2/H_2O analyzer as well as a sonic anemometer these sensors could be observed remotely through cellular connection. The data is represented in flux output ($\frac{\mu mol}{s\,m^2}$) as well as kg CO_2 equivalence of methane outlined by the EPA greenhouse gas inventory. The average daily emissions for this compressor station are estimated to be 136 kg CO_2 equivalent emissions. This study shows that the site during the observational period the compressor station emitted on average are estimated to be 5.43 kg of CH_4 per day.

Methane Emission Monitoring of Appalachian Compressor Station

Roger Andrew Lataille

General Audience Abstract

There has been an increased interest in quantifying and recording methane (CH_4) emissions among all sectors. A main focus of interest among methane is to understand fugitive gasses and emissions resulting from the natural gas sector. Leaks along pipelines are most likely occurring at connection points between components. This study aimed to continuously monitor a pipeline compressor station in Appalachia Virginia. Compressor stations are just one component of the pipeline network as well as the natural gas production and delivery chain attributed with CH_4 emissions.

To monitor methane emissions at the site a stationary eddy covariance monitoring station was installed that was equipped with an open path methane analyzer, open path CO_2 & H_2O analyzer, and a sonic anemometer. The data gathered was used to calculate the flux of methane which is the amount of methane being generated or absorbed by the area of interest. The goal of this study was to continuously monitor methane emissions of a natural gas compressor station. Data presented in this study was collected from January 2021 to April 2021. Data was presented in the flux output ($\frac{\mu mol}{s\,m^2}$) as well as kg CO_2 equivalence of methane outlined by the EPA greenhouse gas inventory.

Dedication

This thesis is dedicated to my loving wife Sarah as well as my family.

Acknowledgments

First, I would like to acknowledge my advisor and committee chairman, Dr. Nino S. Ripepi, for providing the opportunity to conduct this research.

Additionally, I would like to thank my other committee member, Dr. Emily Sarver for helping me discover the opportunity for research within the Mining and Mineral Department.

I would like to thank the following collaborative partners on this project, The Virginia Center for Coal and Energy Research (VCCER), the Virginia Tech Mining and Minerals Engineering Department staff, and ENERVEST Inc.

A special thank you to Richard Bishop from the Mining and Minerals Engineering Department at Virginia Tech, and Jon Lawson from ENERVEST for his support on this project.

Table of Contents

List of Tables

List of Figures

Chapter 1. Introduction

1.1. Background

Climate change is moving to the forefront of legislative and commercial policies, as governments and corporations try to gain a better understanding of greenhouse gas emissions along with reducing emissions. These entities want to gain more data by quantifying emissions at the source level to better understand environmental impacts. The Environmental Protection Agency (EPA) is the federal agency tasked with regulating various emissions. The key greenhouse gasses monitored by the EPA are Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (NO), and fluorinated gases (IPCC 2013). The largest quantity emitted is CO_2 but it does not present the greatest environmental impact. Methane in the atmosphere is considered by the EPA to have a 25 times greater impact on global temperatures over the 12-year atmospheric life span Methane has over the next 100 years compared to Carbon Dioxide *(Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019* 2021 p. 1-10). Methane emissions are produced naturally as well as through human activities. The sectors identified by the EPA (2021) in its emissions report for 1990-2019 as the largest producers of methane include energy, agriculture, and waste management sectors (*Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019* 2021).

Methane is naturally released when biomaterial decomposes, as well as a byproduct of some ecosystems. The scale of decomposition is increased in industrial landfills where heat generated from decomposition increases the rate of generation of methane. Modern regulations require some landfills to capture methane which is then used as a commercial product used by corporations and residents (Environmental Protection Agency 2021, September). During active dumping decomposition starts with and continues long after the landfill use is discontinued and is covered. Landfill emissions account for 17% of the methane generated in the US in 2019 according to the EPA (*Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019* 2021).

Figure 1:1 Covered Landfill with Gas Ventilation Pipes

Agricultural practices within the sector produce methane through raising livestock and managing the manure. The agricultural sector is the largest emitter accounting for 36% of annual methane produced in 2019 when enteric fermentation for Commercial Livestock and Manure management are combined (EPA, *Overview of Greenhouse Gases* 2021). Livestock produces methane during the digestive process also known as enteric fermentation that accounts for 27% of annual methane produced by the U.S. (EPA, *Overview of Greenhouse Gases* 2021). Management of agricultural animal manure accounts for 9% of annual Methane released in the U.S. according to the EPA GHGI Report (EPA, *Overview of Greenhouse Gases* 2021). This sector sees the least amount of regulations in regards to emissions because of the difficulty in reducing each animal's individual emissions.

Figure 1:2 Natural Gas Compressor Station (image courtesy of Richard Bishop)

Natural gas and petroleum sectors are the second-largest emitters at 30% of annual methane generation. These systems generate methane due to the process of extraction and transportation of natural gas as well as the generation of energy. From 1990-2019 the EPA has estimated that methane from the energy sector has decreased by 25.9 % (EPA, *Overview of Greenhouse Gases* 2021). According to the EPA (2021, October) national methane emission spanning all sectors has reduced 13.9% between 1990 and 2019. This has been facilitated through stricter federal and state regulations on most sectors. In addition to government oversite, companies have taken the initiative to self-regulate emissions as well as implementation of emerging technologies into their practices.

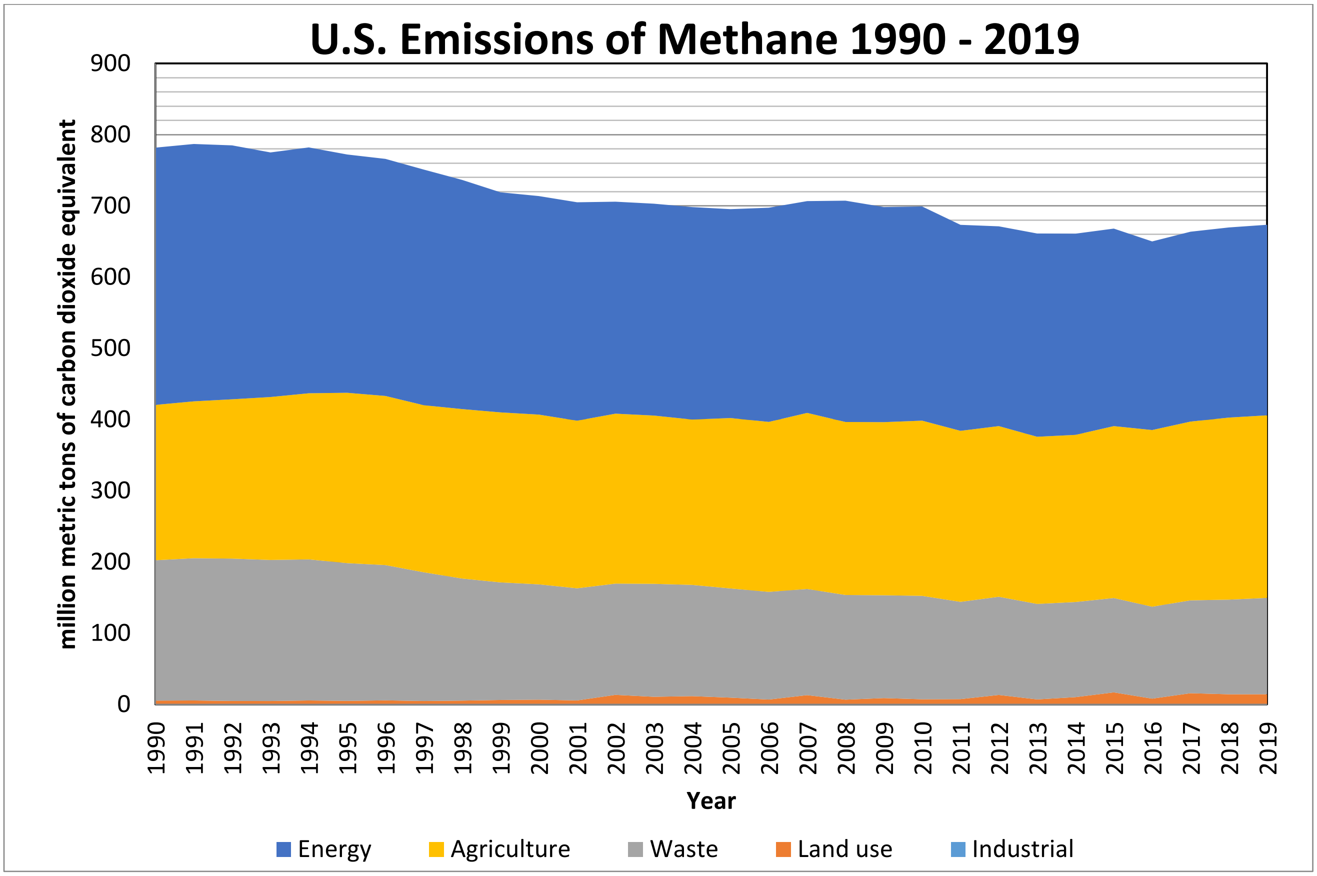


Figure 1:3 U.S. Emissions of Methane from 1990-2019 by Sector. Data from Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019 2021

1.2. Methane and Natural Gas sector

The United States has 72 million natural gas consumers (AGA, 2016). The United States consumed more than 30 trillion cubic feet of natural gas in 2020 (EIA, 2021, October). This vital resource is delivered by 125 pipeline companies maintaining over 2.5 million miles of pipeline (API, 2020). According to the Energy Information Administration (EIA) natural gas provided 40.5% or 1,617 billion kWh of electricity generated in the United States in 2020 (*Frequently asked questions (faqs) - U.S. energy information administration (EIA)* 2021). The EIA found that nearly 49% of homes in the U.S. use natural gas as the primary heating source followed by electricity, which as mentioned previously is partly generated with natural gas (EIA, 2018). This vast network of pipelines expands across the U.S. and is an efficient distribution system to move large volumes of natural gas relatively safely. These pieces of infrastructure need approval from local, state, and in some cases federal agencies to operate. Pipeline construction and operation is strictly regulated by governmental bodies. New pipeline construction faces difficulties in gaining approval from local stakeholders, due to the negative stigma surrounding pipeline safety. Operators are required to disclose the locations of pipelines to the National Pipeline Mapping System (NPMS) (*Why must I submit pipeline data to the NPMS?* 2021).

Figure 1:4 CAT3516 Tale Unit at Compressor Site

Natural gas is produced by drilling into deposits. Extracted natural gas is then transported through gathering lines to processing centers which have separation tanks. These tanks are used to separate the gas from water and oil, resulting in pipeline quality gas. Natural gas is then moved from the processing center through distributing lines the power plants, reserves and to municipalities.

Pipelines require regular maintenance and undergo annual inspections using a variety of techniques and technologies. Pipelines like any other mechanical system are subject to damage or failure without continuous inspection. Failure can be caused by the continuous exposure to the elements as well as extenuating circumstances. Pipeline companies have a financial incentive to maintain the integrity of their distribution network as leaks can cut into profits as well as result in more mechanical failures as well as fines associated with not maintaining regulatory standards. Natural gas is moved through the pipelines by compressor stations which maintain the optimal pressure levels to maintain directional flow in the pipeline. Leaks can result in a loss in pressure causing the engines to run at a higher RPM, which increases the chance of mechanical failure as well as burning more fuel. Additionally, leaks of a large size present a possible safety hazard. Leaks can result in explosions and fires when concentrations of methane reach 4-15% (*Chemical Composition of Natural Gas* 2017). Leaks along natural gas pipelines also emit methane as well as other greenhouse gases. When this occurs it is referred to as a fugitive emission. Natural gas on average is composed of 70-90% methane (*Background* 2013). Leaks can be of varying sizes, some are not an immediate threat but still require repair.

Figure 1:5 Photo of components present at the compressor site

The most common cause of fugitive gas emissions along a pipeline is at compressor stations. This is because leaks occur at connection points between components such as valves a compressor station depending on size could have hundreds of connection points. Seals, O-rings, and gaskets are the main cause of leaks because they are the most susceptible to fatigue or failure during regular operation. Corrosion is another common failure condition that occurs due to standard operation of metal materials (Razvilka 2008). Various components used in the construction of natural gas pipelines are mandated and inspected by various government agencies. These mandated components are intended to reduce the risk and increase pipeline safety. These components could be structural in nature such as a required number of supports or metal composition. They are also in some cases required to reduce fugitive emissions from a component that is partial to fatigue.

Figure 1.2.3 Pipeline Valve at the Site

1.3. Government Oversight

The U.S. Environmental Protection Agency (EPA) works with the scientific community as well as the natural gas sector to increase the quality of data that is used when it estimates the U.S. Greenhouse Gas Emissions Inventory (GHGI). The EPA has various methods of quantifying the expected emissions from compressor stations. These include using the manufacturer emissions estimate for the largest emitter such as the engines using the amount of methane moved through the station. An additional method used to estimate site emissions is to provide an emissions coefficient to each component used at a site (EPA, *Updates Under Consideration to Natural Gas Underground Storage Well Emissions* 2020). These coefficients are added together to achieve an estimated fugitive leak value. The methane emissions data represented in the U.S. GHGI for the natural gas sector is disputed due to the lack of empirical emissions data. It can be difficult to accurately quantify the methane emissions of the large natural gas network when inspections of stations are conducted infrequently and over a short time period. The data gathered by the GHGI will influence the development of new regulations and in turn how the natural gas industry operates.

1.4. Corporate Interest

Government agencies such as the EPA regulate the pipeline companies in efforts to reduce the probability as well as the threat of leaks. Consumers and lawmakers are becoming more environmentally conscious, resulting in more regulation within the energy sector. Regulations can range from approved materials and components for use in new pipeline construction. In addition, regulations can require the replacement of components to meet new standards as well as requiring inspections records for sites. Regulations are trying to address greenhouse gas emissions which are considered to be a major contributing factor to global warming. Governmental agencies are raising the regulatory standards on the natural gas industry requiring them to maintain their pipelines and understand vulnerabilities associated with site operations. Regulations on the energy sector aim to focus on the quantification and reduction of fugitive gas emissions of methane generated along the network. These pipelines are managed by various commercial utility companies. To maintain pressure in a pipeline the natural gas is required to re-pressurize at a compressor station. The industry uses large engines which take gas from the pipeline pressurize it and then reinjects it into the system. The natural gas system is so large it can be difficult to monitor the entire network. With this in mind over 86 natural gas companies have joined the American Petroleum Institute's (API) Environmental Partnership, which aims to increase responsible management practices to reduce leaks through self-regulating. This group works to share their knowledge on efficient ways to improve leak prevention and remediation.

Corporations value safety and share strategies to operate safely. API shares a pipeline safety management system referred to as API RP 1173. This program focuses on internal as well as external stakeholder education. Internally this program obtains buy-in from management, focuses on understanding risk, how to limit risk, conduct internal review, training, and documentation (*API RP 1173 – Pipeline Safety Management Systems* 2020). These steps can help reduce and maintain low levels of risk on sites. To engage the stakeholders this program provides assurances and demonstrates through documentation that the operator is committed to safety.

Chapter 2. Monitoring Methods

2.1. Introduction

There are a multitude of methods utilized to accurately detect methane. Some of these technologies focus on identification of leak locations, while others are used to quantify the leak emissions. These technologies are implemented using stationary and handheld devices designed to perform specific detection tasks. These devices have individual strengths and weaknesses when it comes to identifying leak location and quantification. These devices are consistently evolving and becoming more accurate, efficient and cost effective.

The EPA uses the Leak Detection and Repair (LDAR) Program to identify and reduce fugitive gas leaks. This program has five components that guide reducing leaks at sites for operators as well as inspectors. The LDAR program is a work practice that uses an order of operations for identifying components, leak definition, monitoring components, repairing components and record keeping. The EPA LDAR program method 21 (1998 EPA 305/B-98/011) which in most cases implements a VOC (Volatile Organic Compound) Analyzer. VOC are a group of compounds that can be hazardous, this category includes methane. A VOC Analyzer is a handheld device that uses catalytic, oxidation, flame ionization, infrared absorption, and photoionization to detect fugitive emissions with a high degree of accuracy (*ECFR :: Appendix A-7 to part 60, Title 40 -- test methods* ... 2021). Most of the techniques require the surveyor to physically touch each component of interest at a site with the probe. The EPA recommends use of these sensors due to the fact that they have the capability of accurately identifying leak locations, as well as providing insight onto the severity of emissions. LDAR Method 21 is time consuming, resulting in these inspections typically only being completed on a semiannually basis at each site.

A few of the emerging technologies used to detect methane and other GHGs are infrared thermal imaging (IR), and laser absorption spectroscopy (LAS). These sensor technologies are used in a variety of techniques. LAS techniques utilize a system of sensors to estimate quantities of GHG with methods such as eddy covariance, and tracer gas. Regulators have a differing criteria compared to industry pertaining to preferred sensing devices. Industry focuses on ease of use, and value while maintaining regulatory compliance. While regulators focus on data quality and leak identification (Mikel, 2018). Industries as well as the EPA continuously look to new technologies, or techniques to aid in identifying and quantifying leaks.

2.2. Technology

2.2.1. Flame Ionized Detector (FID)

Flame ionization detectors are the most abundant EPA LDAR program qualified sampling devices. These devices used a closed path system that pulls a sample through a hydrogen-air flame test chamber (*22 The flame ionization detector* 2001). The VOCs percent in the sample are burned creating positively charged ions. The detector works by forcing the created ions to pass over an electrode. The detector outputs a gas concentration proportional to the number of ions that interact with the electrode. This device requires regular pre-sampling calibrations as environmental factors such as humidity and temperature can alter the sensitivity. Additionally, these devices require regular maintenance as the ions created by the hydrogen flame can interfere with the sampling.

Operators of FID must place the nozzle of the sampling probe on the component of interest. This process is very time consuming and does not provide insight on overall site emissions. Some detectors on the market log outputs during an inspection but these devices are used primarily for identifying leaks and determining severity. The output data only provides a small insight into the overall emissions of the leaking component (*22 The flame ionization detector* 2001).

2.2.2. Thermal Imaging

Optical Gas Imaging (OGI) is currently the only way to visualize fugitive gas leaks. This method is preferred by site technicians in identification of leak locations within the natural gas sector. OGI devices are preferred because they do not require recalibration and technical experience is not needed to operate. Additionally, the displays make data interoperation easy. This method has been approved for use in maintaining EPA regulatory compliance in regard to leak detection at some sites. The limitation to OGI is that in most cases there is very limited numerical data on the emission quantity or rate. This technology is at a point where it can be obtained at various cost levels with varying quality of components. Higher quality IR Cameras utilize more sensitive detectors that can determine more minuet changes. Display resolution can be a key factor in being able to identify a leak. Expensive screens have more pixels that show greater detail.

Figure 2:1 Image captured from FLIR camera (image courtesy of Richard Bishop)

OGI devices use one of two types of infrared (IR) imaging these are passive and active. As the name suggests passive imaging detect IR radiation without influencing or altering the ambient radiation. Active IR Imaging implements an IR laser to influence the environment to make gas more visible to the detector. Both passive and active IR imaging cameras implement the same internal components to detect infrared energy and visualize the readings on a display. Each IR imaging camera is design for a specific spectral band to detect certain GHG. Cameras design to observe methane operate with a spectral filter that limits the range to 3.2-3.4 μm (FLIR, 2021).

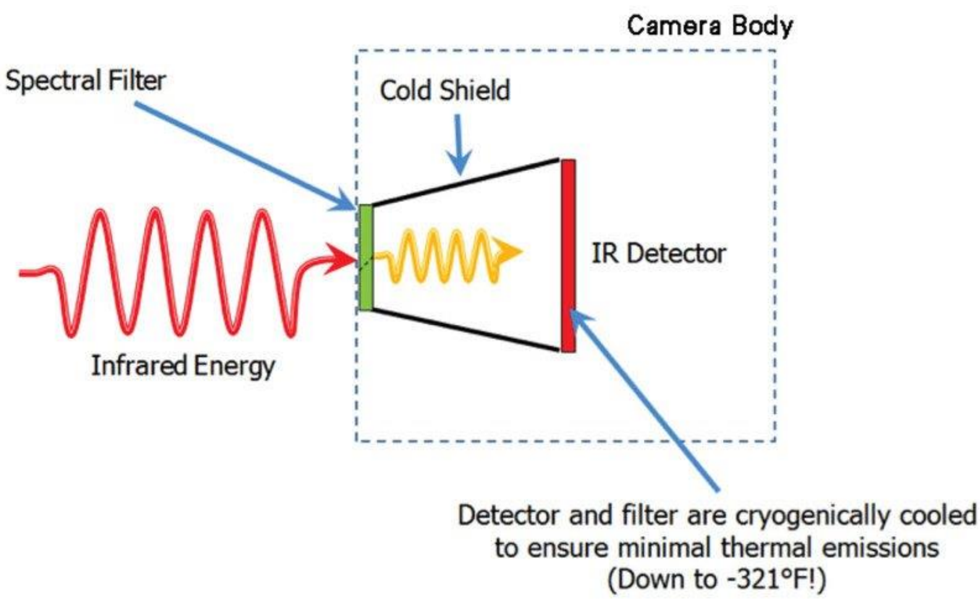


Figure 2:2 Design of Optical Gas Detector (FLIR, 2021)

Although OGI can be easy to operate, there are a few limitations. These can include but not limited to environmental factors affect devices ability to detect leaks, limited data set, and time consuming. This method is faster than the previous standard for EPA Method 21 but still requires the operator to maneuver and focus on each component at a facility. A leak can occur immediately after an inspection and not be noticed until the next required inspection. This also results in site operators not conducting inspections more often than required due to the time it takes. OGI provides information to an inspector or site operator to take action and repair leaks. Environmental factors can influence the minimal detectable leak such as length of survey, the weather conditions, and site layout. Faster surveys have been proven to result in less accurate results (Zimmerle 2020). High wind speeds can make a leak appear small or result in it appearing so small on the display that the operator doesn't observe it. Areas with complex piping can obstruct leaks or leak locations.

Figure 2:3 FLIR camera used to inspect site

2.2.3. Laser Spectroscopy

Laser based sensors are becoming more affordable and specifically built for GHG emissions sampling. These devices implement various types of sampling methods but utilize the same technology. Spectroscopy refers to the interaction of matter and light (Paschotta, *Spectroscopy* 2020). Lasers are frequently utilized as the source of light due to its modularity. Developers can tune aspects of a laser such as wavelength and frequency. The most used method of laser spectroscopy in GHG devices is Laser Absorption Spectroscopy (LAS). The main techniques to perform LAS are direct, and frequency modulation spectroscopy. The basic principle shared by both techniques is that the difference in laser light pre and post the sample path is used to determine details about the sample. The absorption can be interred as a function of the wavelength.

When performing direct absorption spectroscopy, the laser is fixed to a single-frequency. This method uses a laser splitter to observe the difference in optical power of a beam that has passed through a sample region against a reference beam to obtain a measurement. Direct absorption spectroscopy has limited sampling ability due to the single-frequency causing large amounts of sampling noise. Laser noise can be eliminated with the use of modulation in frequency.

Frequency modulation spectroscopy also known as wavelength modulation spectroscopy as the name implies is a method that modulates a lasers frequency over a certain band. This modulation of the frequency allows the sample region to be tested multiple times. This allows for the laser noise to be reduced through comparable data which increases the sensitivity of the sensor. To furthermore reduce noise the sample path can be increased. This is done by increasing the number of times the laser passes through the sample.

Laser Spectroscopy can be implemented in two main configurations for analyzers; these are categorized as closed and open path. Closed path LAS sensors use vacuum pumps to pull samples from the environment into a test chamber. The laser travels through the test chamber to determine details about the sample. An open path system does not have a test chamber. The laser's sample path passes through the environment to a mirror. Open path sensors are considered to be more reliable and efficient than closed path.

LAS can be used in many applications. They allow for rapid response leak detection, as well as continuous monitoring. LAS are a very compact system that can fit into a small form factor. The mobile analyzers allow for various sampling techniques such as handheld or aerial. Although mobile devices quantify leaks the time series is correlated to the time the operator maintains focus on a component. Stationary analyzers can be used to perform long term environmental investigations.

Figure 2:4 Openpath Handheld Laser Methane Mini

A few techniques of using LAS for gas analyzing is tracer gas sampling and flux calculations. Tracer gas sampling is the method of releasing a known quantity of a tracer gas such as propane and Nitrous Oxide (Lilly, 2006). The analyzers have the ability to sample for multiple gases in the test chambers. This method assumes the percentage of trace gas detected is equivalent to the CH_4 and/or CO_2 present. The analyst can then calculate the overall GHG released by the environment during the test period. Flux is defined as the gas exchange in a defined environment. Flux measurements are taken continuously while trace gas sampling is conducted periodically. The tracer gas used to estimate emissions are greenhouse gases thus it would be unethical to continuously release it into the environment.

2.3. Conclusion

When industry members determine which type of sensor to be used at a site they determine value of by comparing the cost vs effectiveness. This cost value it not just the initial capital required to purchase the sensor, but the operating cost of that device. Industry prefers optical sensing methods when applicable because they remain compliant while providing reduced operating costs associated with leak detection. An employee conducting a survey can from a distance inspect multiple components. Stationary sensors are a tool to use to help estimate annual site emissions while requiring very little operating cost after acquisition. The LDAR program has standards for VOC analyzers to reduce data uncertainty and have consistency in reporting.

A list of key criteria of performance was developed to determine the most applicable sensor device for this study. The list of criteria was formulated to identify which device would be able to execute the key objective of the research project. The main objective which is to quantify the methane CH_4 concentrations at a remote compressor station. First, to quantify emissions, the data collected must be represented by a numerical value. To obtain a better estimate of emissions the sensor must collect data over a large time series. The device would need to be robust and reliable, and able to withstand a variety of meteorological conditions. Additionally, due to the remoteness of the site the sensor should function autonomously requiring minimal to no user input after initial deployment. A decision matrix was used to determine which of the discussed sensing methods and techniques would be optimal.

Table 2:1 Decision Matrix: Weight table located in Appendix

Options	Cost	Robustness	Autonomy	Time Series	Data Quality	Score	Rank
Eddy Co	1	4	4	5	3	17	1
Tracer Gas	1	3	3	3	4	14	2
Hand LS	4	5	1	1	3	14	3
Flame Ionized Detector	3	5	1	1	3	13	4
Optical Sensor	3	5	1	1	2	12	5

It was determined that eddy covariance using laser absorption spectroscopy would be able to fulfill the objective. Eddy covariance computes the exchange of molecules or flux over a specified area which is data that can be further investigated. In order to compute a flux the data set must have a large time series. To properly understand the flux of a specified region there needs to be large abundance of data. A stationary sensor has the ability to sample a region without operator input. Eddy covariance has a large upfront cost to obtain the system of sensors required to accurately calculate flux. There are multiple commercial post processing software that can reduce the time it takes to interoperate the data gathered. Eddy covariance sensors are regularly used to conduct GHG flux calculations in remote agricultural and landfill locations. These sensors are designed to be robust and reliable while being left in the field for long periods of time.

Chapter 3. Site Setup

3.1. Site Description

Data from this site was acquired with one eddy covariance monitoring station. The station was located in South West of Virginia in the Appalachian Mountains at a natural gas gathering line compressor station. This station operates two CAT3516 Tale and one CAT3516 B engines. Manufacture emission data for the CAT3516 is provided in the appendix B. During normal operating procedures these engines are functioning at 80% of their maximum output. This compressor station site on average with all engines operating will move 13,000 thousand cubic feet (MCF) of natural gas a month. The site is in a large opening that is surrounded by trees. The nearest road is 85 m from the monitoring station location. There are limited allowable locations for the temporary monitoring station that do not interfere with site safety or operation.

Figure 3:1 Aerial Site View (image courtesy of Richard Bishop)

3.2. Sensory Components

The monitoring station was build using LI-COR Biosciences as well as R.M. Young Company components that are designed and intended to perform eddy covariance measurements. These systems are integrated through the LI-7550 analyser control unit that compiles and stores data from all the sensors. These files are stored electronically as GHG files.

Table 3:1 Monitoring Station Components (LI-COR, 2016) (LI-7500A-Brocure) (R.M. Young Company, 2008)

Data	Sensor	Manufacturer	Sampling Rate
CH_4	LI-7700	LI-COR Biosciences	10 Hz
CO_2& Water Vapor	LI-7500A	LI-COR Biosciences	10 Hz
Wind speed, Direction, & sonic temperature	Young 8100VRE Sonic Anemometer	R.M. Young Company	10 Hz

The LI-7700 LI-COR Methane analyser is an open path LAS sensor that measures methane concentrations. The laser used in the analyser becomes saturated at 40 ppm of methane, typical ambient methane is around 1.5 ppm to 5 ppm. It has high speed and precision capabilities of 5 ppm at 10 Hz. The analyser can take measurements at 10 Hz up to 20 Hz. This system has an onboard wash system to keep the bottom mirror clean to maintain signal strength. Additionally, it is equipped with a heater to keep snow and ice from forming on the reflector. It is designed to operate -12℃ to 50℃ (LI-COR , 2016) .This sensor has an optical path of 0.5m which is traveled 60 times for a total sampling path of 30m (LI-COR , 2016).

Table 3:2 LI-7700 Analyzer Details (LI-COR, 2016)

Component	LI-7700	
CH4	Temp	Pressure
$\frac{Mmol}{m^3}$, $\frac{\mu mol}{mol_d}$, $absorptance$	℃	kPa

The LI-7500A is a CO_2 and water vapor analyser using non-dispersive infrared detection. Infrared radiation is emitted from the base and travels a sampling path of 12.5 cm with a beam diameter of 8 mm. Concentrations data can be output at 10 Hz – 20 Hz. High speed and precision 0.11 ppm CO_2 and 00.47 ppt H_20 at 10 Hz. This analyser was designed to operate from -25℃ to 50℃ (*LI-7500A-Brocure*). To maintain signal strength the analyser is installed at an angle to prevent water from conjugating on focusing lens.

Table 3:3 LI-7500A Analyzer Details (LI-7500A-Brocure)

Component	LI-7500A		
CO2	H20	Temp	Pressure
$\frac{Mmol}{m^3}$,$\frac{\mu mol}{mol_d}$, $absorptance$	$\frac{Mmol}{m^3}$,$\frac{mmol}{mol_d}$, $absorptance$	℃	kPa

Young's 8100VRE Sonic Anemometer measures the wind speed, wind direction and sonic temperature. A sonic anemometer sends ultrasonic sound waves between receivers. The time for the wave travel between transducers is known in a controlled environment. The difference in the actual reading and the reference is used to determine wind speed. Wind direction is acquired by increasing sampling to three dimensions with multiple transducers. Sonic temperature can be "derived from speed of sound which is corrected for crosswind effects." (R.M. Young Company, 2008). Anemometer is designed to measuring range for wind speeds are 0 to 90 mph, wind direction is 360 degrees, and Sonic temperatures are -50℃ to 50℃ (R.M. Young Company, 2008).

Figure 3:2 Young’s Anemometer and LI-7700 in place at Site (image courtesy of Richard Bishop)

3.3. Monitoring Station

The sensors and supporting equipment were mounted to a heavy-duty tripod. The tripod was set to the max mounting height for 4 m (13 ft). The tripod requires the instillation of stability spikes limiting the allowable deployment locations at the site due to underground cables. The tripod had to be placed on level ground to ensure long term placement security. As the area around the compressor site has experienced landslides. Other key limiting placement factors included access to power as well as prevailing wind direction.

Figure 3:3 Monitoring Station Equipped with, LI-7700,LI-7500A, and Young's Anemometer

3.4. Eddy Covariance

Eddy covariance is a fixed box flux calculation of environmental exchange. Flux is the amount of something that passes through a defined area over time. An area that generates a positive net flux is called a source when an environment generates a net negative flux it is referred to as a sink. Net flux is the flux over a long period of time. Due to air flow in an ecosystem flux is not constant over an area. Airflow in an ecosystem is driven by heat exchange. Heat exchange generates turbulence in which low density hot air rises while cold more dense air sinks. This cycle creates an airflow phenomenon known as eddies. These eddies carry particles in a vertical circular motion.

Figure 3:4 Depictions of Eddies (Burba, 2013, p.12)

Eddy covariance measures flux by sampling an eddy moving upward carrying molecules up then compares that to an eddy that is moving downward with more or less molecules. This is known as vertical flux. The sensor must be placed downwind as wind carries molecules to the monitoring station. The area in which the station can sample upwind is known as the fetch. Fetch is determined mainly by the height of the sensors, surface roughness and airflow stability. Airflow stability is the amount of turbulence or mixing that is occurring. This can change during different times a day when the sun isn't driving as much heat exchange. Surface roughness refers to the variance in the geography or canopy upwind of the sensor this can decrease the fetch of the analyser.

Eddy covariance calculates methane flux using the three sensors placed at the monitoring station. This station was placed down wind of the prevailing wind direction determined from site operates was North West. Sampling must be at least 10 Hz or sampling rate of 10 times per second. This rate is required due to the fact eddies move very quickly and a slower sampling rate would not be able to sample the eddy. Additionally, to determine methane flux at the station a CO_2 / H_2O analyser is required to correct for water vapor contributions to the CH_4 reading by the LI-7700 system when calculating flux. The LI-7200A would also allow for the calculation of CO_2 flux which was not investigated in this study. The sonic anemometer is used to measure wind variables as well as the sonic temperature of the site.

Figure 3:5 Compressor Station (image courtesy of Richard Bishop)

The fundamental principle of eddy covariance is to generate a correlation between concentration of interest and vertical wind speed (Burba, 2013). Eddy covariance operates at 10 hz so that the small eddies passing through the monitoring station can be sampled. First the station will sample an eddy carrying a pocket of air down while sampling wind speed. Then the station will sample an upward eddy transporting a pocket of air at a known wind speed. These air pockets contain independent characteristics such as gas molecules, temperature, and humidity. If we compare the two pockets of air we can determine vertical flux of gas molecules of interest as well as other components of interest.

The fundamental physical principle of eddy covariance is observing the difference in vertical transport of molecules over time in relation to a vertical wind speed (Burda & Anderson, 2010). This is done by observing a mean flow of air which carries gas molecules through the sampling region. The sampling region alters the quantity of molecules in the flow. This can be through environmental uptake or release of the molecules. The monitoring station then monitors the quantity of molecules present in an upward traveling eddy and comparing it to a downward traveling eddy. The difference in molecules present in each eddy will provide the flux. This sampling done over a half hour period will be able to estimate the flux of the sampling region.

Mathematically a vertical flux can be represented as a covariance between measurements of vertical velocity, the upward and downward movements, and the concentration of the entity of interest [Burba, 2013, eq.1]. This vertical flux of molecules can be represented by a mathematical correlation between turbulent flow factors and quantity of molecules.

$$F = \overline{\rho_d w s} \tag{1}$$

Factors contributing to turbulent flow are vertical transport due to air density (ρ_d) as well as vertical wind speed (w). Air density change is driven by heat exchange. To estimate the quantity of the molecules of interest its' dry mole fraction (s) is used. Air density change is driven by heat exchange. To estimate the quantity of the molecules of interest its' dry mole fraction (s) is use. Turbulent flow can be mathematically represented by equation (1) which equation (2) eddy flux equation can be derived from. Eddy flux equation [Burba, 2013, eq.2] for any gas can be derived from the base flux equation with the assumption that mean vertical flow is negligible.

$$F = \overline{\rho_d}\ \overline{w's'} \tag{2}$$

Chapter 4. Results

4.1. Introduction

This Study hopes to provide more insight into the quantity of methane at a compressor station along a natural gas pipeline. There is not a standard size or configuration for a natural gas compressor station. These results are not representative of all compressor stations. The monitoring station was observing three active compressor engines operations at 80% of max flow. Monitoring data was continuously compiled into greenhouse gas files (.ghg) for every thirty-minute period which are used to generate flux outputs from January 2021 to April 2021. The methane mass flux data is represented as $\frac{\mu mol}{s\,m^2}$ as well as the EPA standard for GHGI of CO_2 equivalence.

$$\frac{\mu mol}{s\,m^2} * 10^{-6}\frac{mol}{\mu mol} * 16\frac{gram}{mol} * 10^{-3}\frac{kg}{g} = \frac{kgCH_4}{s\,m^2}$$

$$\frac{kgCH_4}{s\,m^2} * 60\frac{s}{minutes} * 30\,min = \frac{kgCH_4}{m^2}$$

The EPA uses a conversion factor of 25 which is a representation of the impact CH_4 has compared to CO_2 when in the atmosphere. The area used in the conversion is the area of the compressor station. This area was estimated to be 4,000m^2. The determination of area of interest was to include potential leak locations for the site. Time extrapolation of flux was converted to an hourly output. To obtain $CO_2\ Equivianlence$ for Methane eq. 3 [EPA, *Overview of Greenhouse Gases* 2021] is used.

$$CO_2\ Eq. = (kg\ of\ gas)\ x\ (Global\ Warming\ Potential) \quad (3)$$

4.2. Daily Emissions per month

The flux is output is in thirty-minute periods complied from 10 samples per second. These data points can be ruled not valid if any individual component of the data associated with computing the flux in not adequate such as analyzer signal strength. Low signal strength can be caused by weather conditions or dust on the reflecting lens. The valid data points can be averaged to obtain a daily average of flux.

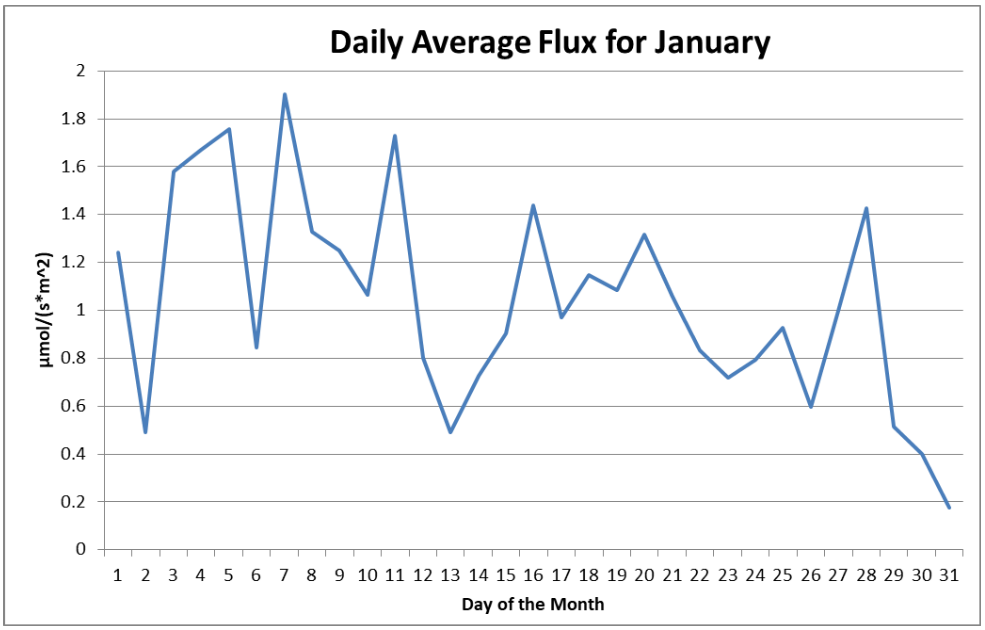


Figure 4:1 Daily Average Flux in $\frac{\mu mol}{s\,m^2}$ *for January 2021*

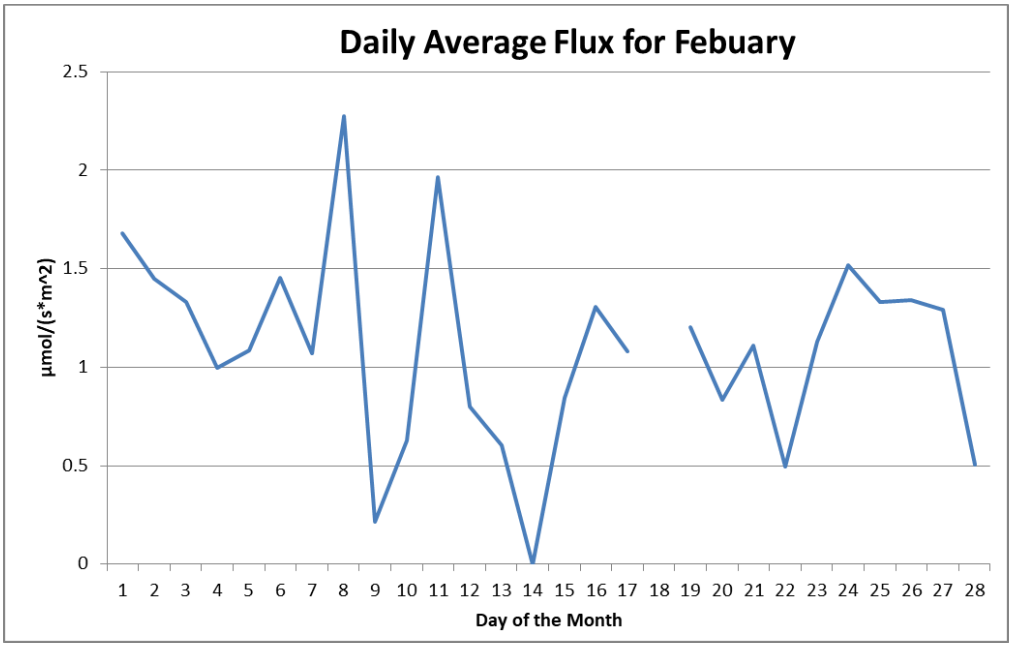


Figure 4:2 Daily Average Flux in $\frac{\mu mol}{s\,m^2}$ *for February 2021*

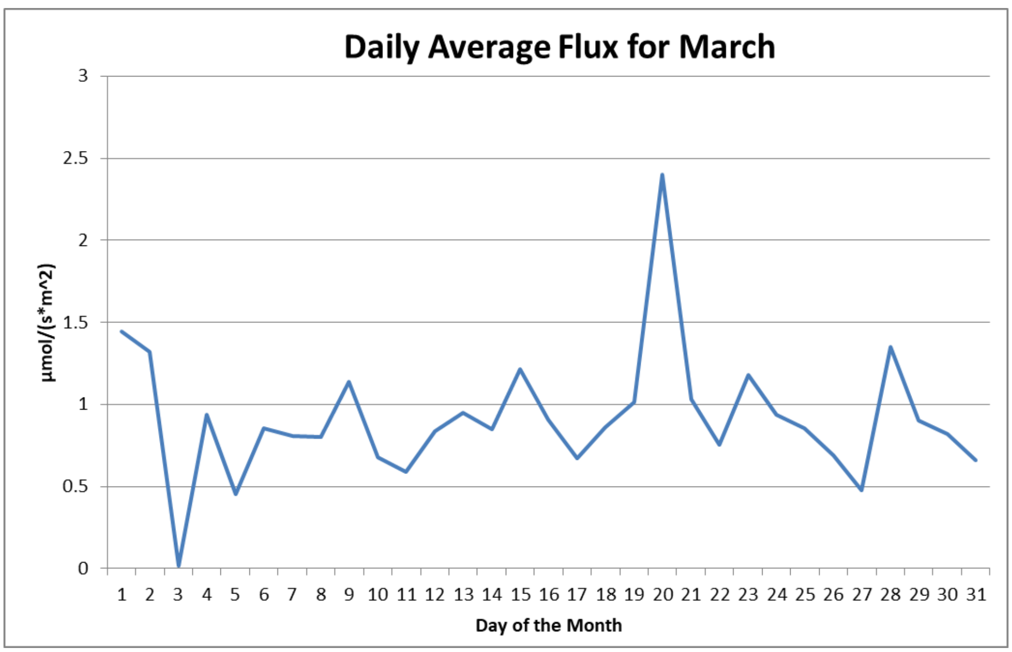


Figure 4:3 Daily Average Flux in $\frac{\mu mol}{s\,m^2}$ *for March 2021*

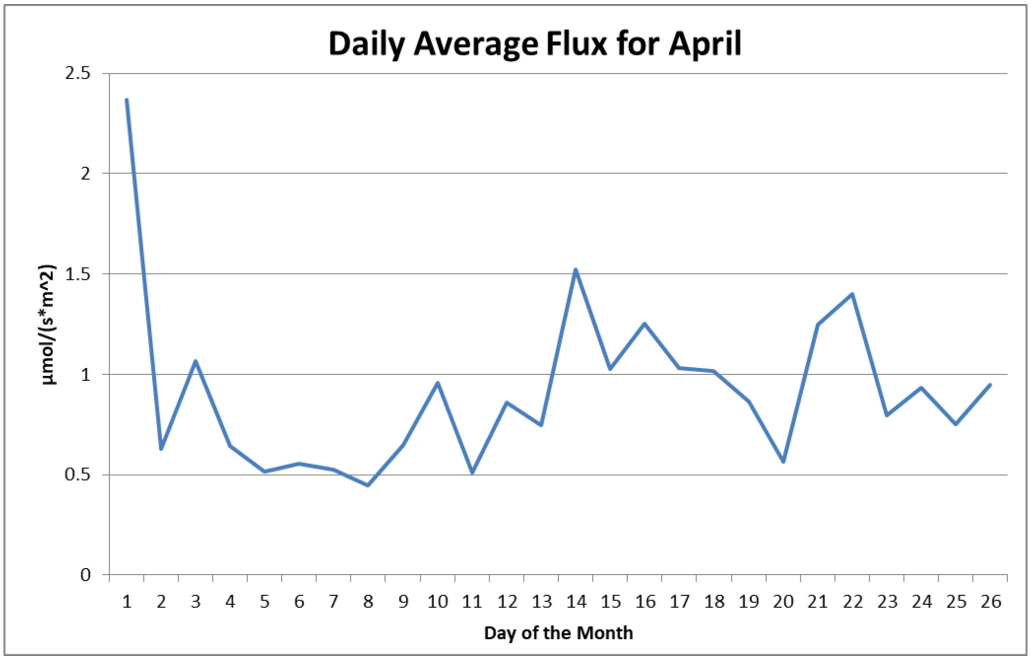


Figure 4:4 Daily Average Flux in $\frac{\mu mol}{s\, m^2}$ for April 2021

The average flux reading can be interpreted into the daily emissions by multiply the daily average of output by 48 for the total number of half hours in a day.

Table 4:1 Average Daily Emissions

Average Daily Emissions			
	kg CH_4	kg CO_2 Equivalence	Flux Output
January	5.74	144.32	1.038
February	6.05	143.68	1.095
March	5.07	125.77	0.916
April	4.84	121.10	0.917

4.3. Monthly Accumulation

The daily emissions data can also represent as monthly accumulation. To obtain this interpretation of the data the daily 30-minute average of CO_2 equivalent data is multiplied by 48 half hours to convert it into 24-hour average of emissions. Daily emissions are then added together to acquire the accumulation over the month.

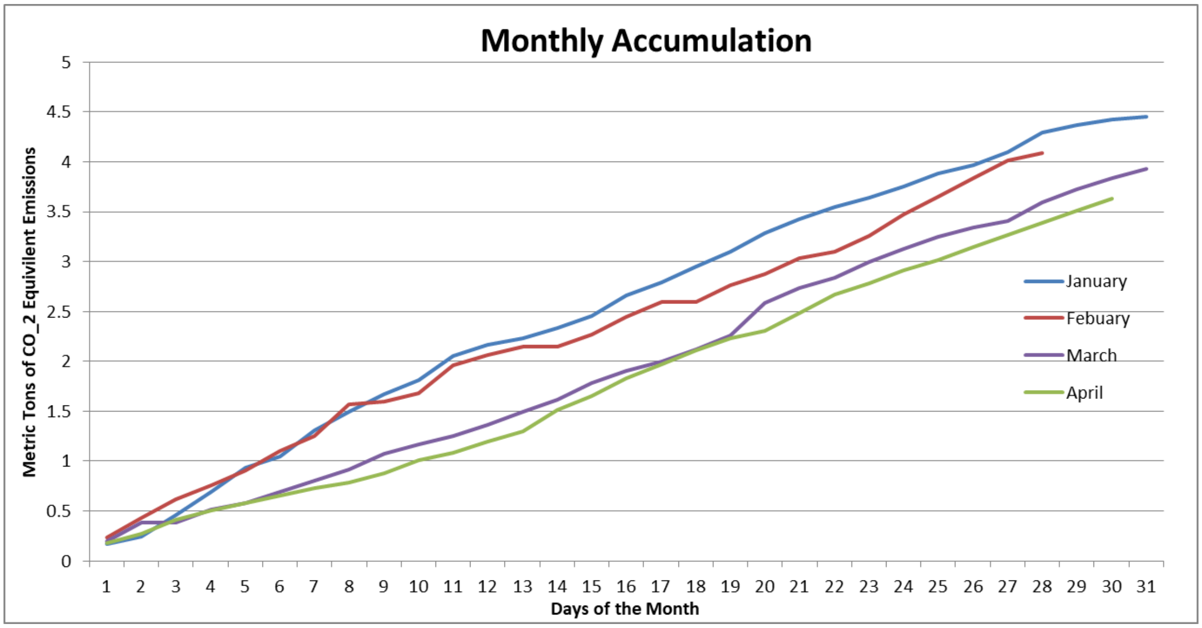


Figure 4:5 Monthly CO_2 equivalent emissions accumulation in Metric Tons

4.4. Blow off Sampling

When one of the Engine units undergoes maintenance the line must be depressurized. This event is referred to as a blow off. Figure (4.3.1) displays the monitoring stations ability to capture the emissions spike associated with blow off and flux decrease during the maintenance period on March 3rd 2021. Located in appendix A is a record of maintenance that occurred at the site during the testing period. Not all maintenance events resulted in a blow off and pressurization of the pipeline.

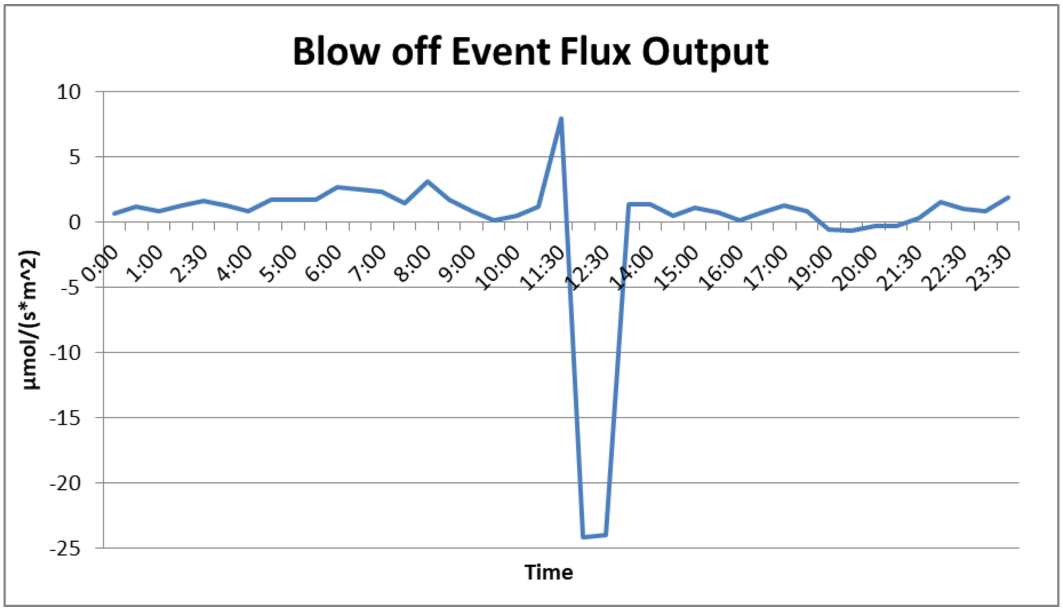


Figure 4:6 Flux Output $(\mu mol)/(sm^2)$ for Blow off Event March 3 2021 0:00 - 23:00 EST

The flux data output for March 3rd shows that after shutdown there is a dip in methane leaving the area. After the large peak during blow off the levels of methane in the area drop dramatically. Once repairs are complete and the engines are turned back on the flux returns to similar levels pre shutdown.

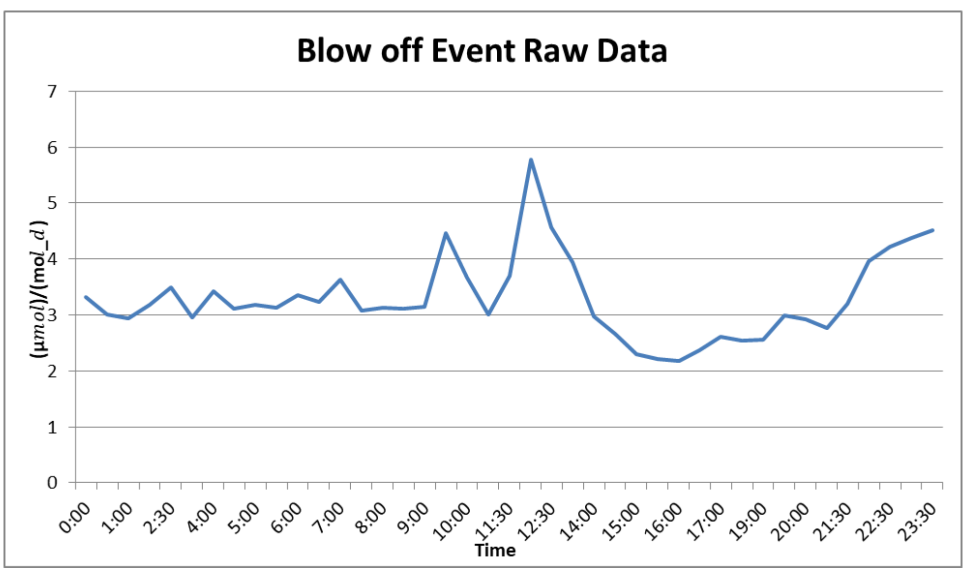


Figure 4:7 LI-7700 Methane output Blow off Event March 3 2021 Raw data $(\mu mol)/(mol\_d)$

The peak blow off can be observed in the flux data as well as the raw methane reading for the monitoring station. The local methane levels drop below pre blow-off levels during the shutdown period.

4.5. Real Time Data Observation

During this blow off event and other similar peak emission the data was being monitored off site in real time. The site operator was notified when methane readings peaked to see if a blow off event or maintenance was underway. The real time data with the configuration used in this study does not output flux data but the LI-7700 analyzer, LI-7500A analyzer as well as Young 8100 anemometer readings can be observed.

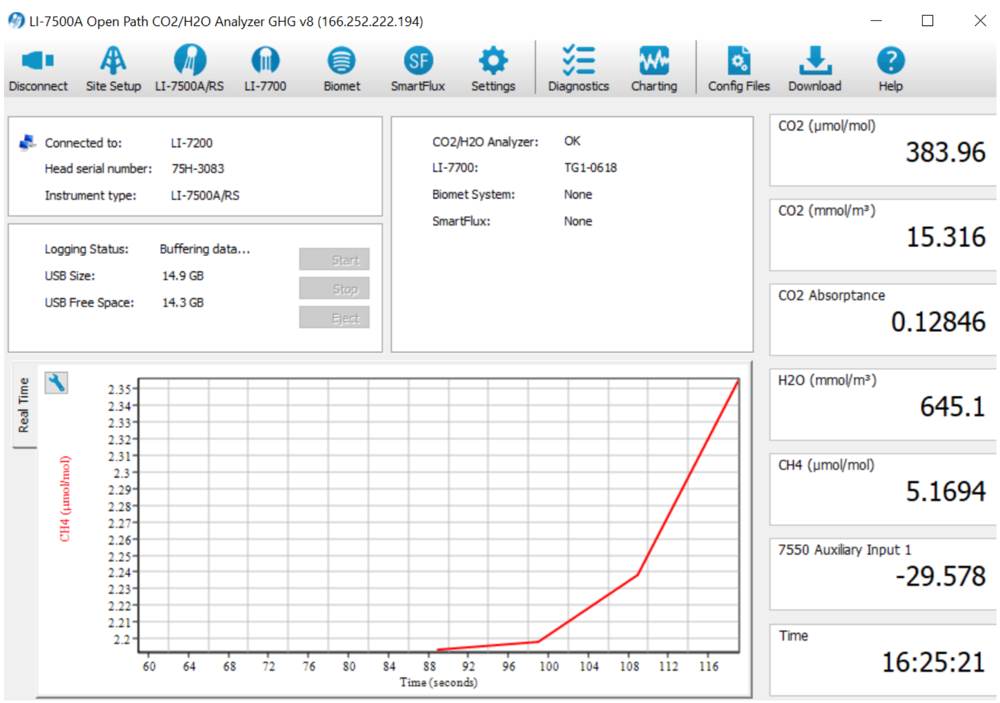


Figure 4:8 Interface for remote sensing

4.6. Stack Emissions Testing

On June 22, 2021, all three units located at the site underwent emissions testing for CO, NOx, and VOCs. The permitted limits of emissions are based on regulations 40 CFR 60 Subpart JJJJ and VADEQ Permit. The Two CATERPILLAR G3516 Tales are permitted to have annual VOC emissions of 6.73 tons per year (CECO 2021). The CATERPILLAR G3516 B is permitted to emit 3.46 tons of VOC per year (CECO 2021). The emissions testing were conducted to determine the annual emissions from the unit's exhaust stack.

The sampling process was conducted with an emission testing unit produced by Compressor Engineering Corporation. The process samples emissions for each unit while operating at maximum output for 60-minutes. This is conducted three times to fulfill regulatory testing requirements. The samples are pulled into the emissions testing unit from the unit undergoing testing. The sample's temperature is maintained as portions of it are distributed to various analyzers. During testing it was determined that of the VOCs emitted from the stack 97% is methane.

Table 4:2 Stack Emissions Tests for 40 CFR 60 Subpart JJJJ and VADEQ Permit (CECO 2021)

Make & Model	Unit	Permitted	Emitted
		tons / year	
Caterpillar G3516 TALE	41	6.73	0.855
Caterpillar G3516 TALE	42	6.73	0.514
Caterpillar G3516 B	45	3.46	1.062

Stack emissions testing estimates do not account for all sources of methane from a unit such as fugitive emissions. The Flux data converted to tons of methane can be compared with the results from the stack testing. The average monthly emissions monitored by the eddy covariance station were 355 lb. of CH_4. The average monthly emissions can be converted into an annual estimate of 2.179 tons of CH_4 per year. Compared to the total emission estimates from the stack emissions testing of 2.431 tons of VOC per year (CECO 2021). Of which is estimated to be 2.351 tons of CH_4. The permitted emissions for the compressor station are 16.92 tons of VOC per year (CECO 2021).

4.7. Errors in Sampling

Errors in eddy covariance sampling can occur for a multitude of reasons. If the station is only operating with a methane sensor and not accompanied by an $H_2 0$ analyzer necessary corrections will not be made to the output flux data. Water vapor can be interpereted as methane by the LI-7700 analyzer but with the LI-7500A analyzer, this can be corrected to achieve a more accurate flux.

Figure 4:9 Back of Compressor

An error can also result from site setup where objects within the fetch can alter downstream flow to the sensor. The obstructions can break larger eddys into a smaller eddys that are too small to be captured accuratly by the station. Additionally the fetch distance will decrease with an increase in site roughness. Roughness at this site was potentially influenced by utility buildings holding tanks, and pipes. The flow of air moving to the sensor could also be influenced by turbulence generated for the geographical location of the site. The site is located on a along the blueridge mountain range. More turbulent flow could be created by a weather system moving over the mountain potentially keeping methane in the area allowing for more mixing near the sensor. It could also result in a higher estimates on methane emissions as some methane would not be able to leave the area.

Chapter 5. Conclusion & Future work

5.1. Conclusion

Methane monitoring that took place in Dickenson County, Virginia was successful in quantifying emissions from a natural gas pipeline compressor station. The sample region contained two CAT3516 Tale and one CAT3516 B engines and associated piping. Observation began in January 2021 and data provided into April 2021. Leaks are most likely to occur at connection points and valves. Compressor stations have a large abundance of these components making them susceptible to fugitive gas leaks.

To place a value on the emissions from this compressor station we can use a carbon tax. A carbon tax is the idea of placing a monitory disincentive to emitting CO_2 into the atmosphere. The average carbon tax for emitting CO_2 comparing all nations that have the program implemented is approximately $45 per ton (Patnaik & Kennedy, 2021). This site is permitted to emit 128.11 tons of CO_2 as well as 423 tons of CO_2 equivalent emissions of CH_4. The permitted emissions if subject to a carbon tax would equate to $25,000 per year. This site based on regulatory testing has an estimated annual emissions of CO_2 of 13.4 tons as well as 60.8 metric tons of CO_2 equivalent emissions of CH_4. If these emissions were subject to an annual carbon tax it would have an estimated cost of $3,340 per year. To recoup capital costs of this eddy covariance system alone it would take roughly 20 years.

It was determined that eddy covariance would be the best sensory system to quantify methane emissions. This study supports the decision matrix used to make that determination to fulfill requirements of this study, which was to continuously monitor the compressor station for

Methane. The eddy covariance monitoring station was able to withstand various weather conditions and remain functional during the test period. Data was continuously gathered as .ghg files. Data was only missing for days with large amounts of rain or snow. The sensor didn't require physical lens cleaning during this period as the heater and sprayer in combination with the spin motor allowed the sensor to maintain high signal strength.

The station was successfully monitored offsite with observation of real-time methane levels at the compressor station. Site monitoring also captured a blow off event, which occurs when the lines connected to a compressor undergo depressurization. The site implements a system that tracks the amount of natural gas flowing through the station. If the flow decreases significantly operators are then notified. Medium to small events can be missed by this type of system. In contrast, the monitoring station that was in place was shown to have the ability to potentially track these events. This capability to provide real time monitoring can help identify leaks to deploy a site operator to perform a site check is a tool companies and agencies can use to better utilize staff. The eddy covalence monitoring station provided raw methane readings as well as CH_4 flux data. The Flux data was used to quantify the fugitive gas emissions for the compressor station.

The compiled monthly data provided for the months of January 2021 to April 2021 was a daily average of methane emissions of thirty-minute period. The average daily output for this compressor station is estimated to be 161 kg CO_2 equivalent emissions. The environmental impact of this compressor station can be compared to the agricultural sector. Studies have shown that on average cattle can emit roughly 100 grams per day or 36.5 kg of CH_4 per year (Prajapati, 2017). This study shows that the site during the observational period the compressor station emitted on average 5.43 kg of CH_4. The CH_4 emissions from the compressor station would be equivalent to the emissions for 54 cattle. It can be determined that 0.06% of the total volume of natural gas moved through the site by the three operating compressors was lost each month in emissions. No other long-term methane monitoring systems were in place at the research site to compare data. It is recommended that further investigation into this compressor stations CH_4 emissions is conducted.

I would not recommend the installation of an eddy covariance monitoring station unless new regulations mandated that compressor sites deploy a continuous monitoring sensor. The capital cost is too large compared to estimated lost in emissions of one site. An eddy covariance station could be mobile but would suffer from potential fetch and surface roughness issues. This system is expensive, requires setup and preparation to install and can only be used at one site during a given time period. Alternatively, a site operator could pay a similar capital cost and configure a trailer to preform tracer gas sampling. This trailer could be easily moved from site to site allowing for the maximum value. The key components that should be taken to account upon placement is wind direction and orienting the trailer in the proper cardinal direction. Although this would not be able to continuously approximate the site emissions. It could be operated frequently enough to acquire a large enough data set to estimate monthly emissions for each site. Further investigation is required to determine how and where to release the tracer gas on a site of this size and how to determine how much of all site emissions are being viewed by the sensor.

5.2. Future Work

Additional research with this sensor and this location is recommended to validate the findings of this study. To validate the findings this, study the monitoring could continue with the current station to observe the annual trends. Annual trends could be used to obtain baseline data for each month. This project could also be completed with some changes in respect to the site set up. A more permanent monitoring station with analyzers at a higher elevation would result in better data due the reduce interference from site structures. More tests of this system at a location that currently implements a methane monitoring system or to add a tracer gas system to the monitoring station to obtain comparable data. Additionally, in conjunction with the DOE monitor on the site for an extended period of time would aid in gaining comparative data. The future site could have less geographical variables.

An investigation into the CO_2 data gathered by the monitoring station to glean insight into what percentage of the stack emissions the monitoring station detected during the sampling period was not completed. It is not recommended to conduct this comparison as there are potentially more CO_2 emitters. Additionally it can be difficult determine the absorption of CO_2 by the surrounding vegetation.

The compressor site used for this study mostly implements an infrared camera to detect and fix leaks. It allows for operators to quickly identify the leak location and to see the extent. These cameras have a sensor that can detect thermal radiation. If the technician knows the area in which the leak they can quickly identify where a patch needs to be applied. A common technology that has various applications is laser absorption spectroscopy. This is using a trained laser to detect the amount of a specific gas. These sensors are now being implemented with automated drones.

Figure 5:1Programmable drone with methane sensor (image courtesy of Richard Bishop)

A system of monitoring techniques would provide the best fugitive gas detection as well as emissions quantification. Each method has its own strengths and weaknesses. Combining technologies will reduce greenhouse gas emissions by filling in the gaps between sensor capabilities. More research could be done on using the real time data to deploy a drone to perform autonomous monitoring of a site. Additionally, further investigation into a mobile monitoring station as an alternative to continuous monitoring should be conducted.

References

AGA. (2016). *NATURAL GAS: THE FACTS*. Retrieved May 5, 2021, from https://northeastsupplyenhancement.com/wp-content/uploads/2016/11/Natural-Gas-Facts.pdf.

Agilent Technologies, Inc. (2001, May 16). *22 The flame ionization detector.* Agilent 6890N Gas Chromatograph. Retrieved February 24, 2020, from http://www.ecs.umass.edu/eve/facilities/equipment/Agilent6890/The%20Flame%20Ionization%20Detector.pdf.

Air Quality Planning and Standards, & Mikel, D. K., EPA 454/B-18-008 (2018). EPA. Retrieved May 17, 2020, from https://www.epa.gov/sites/default/files/2018-08/documents/gd-52v.2.pdf.

API. (2020). *API RP 1173 – Pipeline Safety Management Systems*. Energy Infrastructure. Retrieved June 20, 2021, from https://www.energyinfrastructure.org/pipeline/pipeline-safety.

API. (2021). *Why pipelines?* Energy Infrastructure. Retrieved August 11, 2021, from https://www.energyinfrastructure.org/pipeline/why-pipelines.

Burba, G. (2013). *Eddy covariance method for scientific, industrial, agricultural, and regulatory applications: A field book on measuring ecosystem gas exchange and areal emission rates*. LI-COR Biosciences.p.12, p.18, p.19

Burda, G., & Anderson, D. (2010). *Brief Practical Guide to Eddy Covariance Flux Measurements*. LI-COR. Retrieved February 20, 2020, from https://www.licor.com/env/pdf/eddy_covariance/Brief_Intro_Eddy_Covariance.pdf.

EIA, Emissions of Greenhouse Gases in the United States 2009 (2011). Retrieved July 11, 2021, from https://www.eia.gov/environment/emissions/ghg_report/pdf/0573%282009%29.pdf.

EIA. (2021, November). *Frequently asked questions (faqs) - U.S. energy information administration (EIA)*. Frequently Asked Questions (FAQs) - U.S. Energy Information Administration (EIA). Retrieved November 11, 2021, from https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.

EIA. (2021, October). *Table 4.3 Natural Gas Consumption by Sector*. EIA. Retrieved October 10, 2021, from https://www.eia.gov/totalenergy/data/monthly/pdf/sec4_6.pdf.

Eli Lilly and Company. (2006). (tech.). *Tracer Gas Protocol For the Determination of Volumetric Flow Rate Through the Ring Pipe of the Xact Multi-Metals Monitoring System*. Lafayette, IN. Retrieved March 23, 2021, from https://www.epa.gov/sites/default/files/2020-08/documents/otm24.pdf.

Enbridge Gas. (2017). *Chemical Composition of Natural Gas*. Enbridge. Retrieved 2021, from https://www.enbridgegas.com/about-enbridge-gas/learn-about-natural-gas.

Enforcement and Compliance Assurance, & EPA 305/B-98/011, Inspection Manual: Federal Equipment Leak Regulations for the Chemical Manufacturing Industry (1998). Washington, DC; U.S. Environmental Protection Agency, Enforcement and Compliance

Assurance. Retrieved 2020, from https://archive.epa.gov/compliance/resources/publications/assistance/sectors/web/pdf/insmanvol1.pdf.

EPA 430-R-21-005. (2021, April 5). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019*. Environmental Protection Agency. Retrieved June 11, 2021, from https://www.epa.gov/ghgemissions.

EPA, Inventory of U.S. GHG Emissions and Sinks: Revision Under Consideration for Gathering and Boosting Emissions (2016). Retrieved September 11, 2020, from https://www.epa.gov/sites/default/files/2016-08/documents/proposed_revision_to_ng_gathering-boosting_segment_emissions_2-2-16.pdf.

EPA. (2021, October). *Overview of Greenhouse Gases* . EPA. Retrieved November 14, 2021, from https://www.epa.gov/ghgemissions/overview-greenhouse-gases.

EPA. (2021, September). *Basic Information about Landfill Gas* . EPA. Retrieved October 14, 2021, from https://www.epa.gov/lmop/basic-information-about-landfill-gas.

FLIR. (2021). *The science behind Optical Gas Imaging*. Teledyne FLIR. Retrieved March 24, 2021, from https://www.flir.com/discover/instruments/gas-detection/the-science-behind-optical-gas-imaging/.

Hendryx, M., & Luo, J. (2020). Natural gas pipeline compressor stations: VOC emissions and mortality rates. The Extractive Industries and Society, 7(3), 864-869. https://doi.org/https://doi.org/10.1016/j.exis.2020.04.011

Compressor Engineering Corporation (CECO). (2021) *Emission Test Report VA Unit 41,VA Unit 42, VA Unit 45.*Houston, TX, Hythier Antoine.

Inventory of U.S. Greenhouse Gas Emissions and Sinks, & EPA, EPA (2020). Environmental Protection Agency. Retrieved 2021, from https://www.epa.gov/sites/default/files/2020-11/documents/ghgi-webinar-nov2020-wells.pdf.

IPCC, 2014: *Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)].

LI-COR. (2016). *Li-7700 Open Path CH4 Gas Analyzer* (5th ed.). LI-COR Biosciences.

LI-COR Biosciences. (n.d.). *LI-7500A Brochure*. Retrieved April 3, 2021, from https://www.licor.com/env/pdf/gas_analyzers/7500A/LI-7500A_brochure.pdf.

Natgas. (2013, September 20). *Background*. NaturalGas.org. Retrieved 2021, from http://naturalgas.org/overview/background/.

Natgas. (2013, September 20). *The Transportation of Natural Gas*. NaturalGas.org. Retrieved February 16, 2020, from http://naturalgas.org/naturalgas/transport/.

National Archives. (2021, August). *ECFR :: Appendix A-7 to part 60, Title 40 -- test methods ...* Code of Federal Regulations. Retrieved November 11, 2021, from https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/appendix-Appendix%20A-7%20to%20Part%2060.

NPMS. (2021). *Why must I submit pipeline data to the NPMS?* National Pipeline Mapping System. Retrieved July 16, 2021, from https://www.npms.phmsa.dot.gov/WhyMustSubmit.aspx.

Office of the Federal Register, National Archives and Records Service, General Services Administration, Chapter 1Code of federal regulations. title 40, protection of environment: Revised as of September 11, 2021 (1981). Washington.

Patnaik, S., & Kennedy, K. (2021, October 7). *Why the US should establish a carbon price either through reconciliation or other legislation*. Brookings. Retrieved December 20, 2021, from https://www.brookings.edu/research/why-the-us-should-establish-a-carbon-price-either-through-reconciliation-or-other-legislation/

Paschotta, D. R. (2020, March 14). *Spectroscopy*. spectroscopy, explained by RP Photonics Encyclopedia; principles, methods, modulation spectroscopy, trace gases, Doppler-free, applications. Retrieved October 21, 2020, from https://www.rp-photonics.com/spectroscopy.html

Paschotta, D. R. (2020, March 14). *Laser Absorption Spectroscopy*. Laser absorption spectroscopy, explained by RP Photonics Encyclopedia; principles, methods, modulation spectroscopy, trace gases, Doppler-free, applications. Retrieved March 20, 2021, from https://www.rp-photonics.com/laser_absorption_spectroscopy.html.

Prajapati, P., & Santos, E. A. (2017). Measurements of methane emissions from a beef cattle feedlot using the eddy covariance technique. *Agricultural and Forest Meteorology, 232*, 349-358. https://www.sciencedirect.com/science/article/abs/pii/S016819231630380X

R. M. Young Company. (2008, February). *Ultrasonic anemometer model 81000re*. YoungUSA. Retrieved October 25, 2019, from https://www.youngusa.com/wp-content/uploads/2008/02/81000RE-9028C29.pdf.

Razvilka. (2008). *Methane Emissions Reduction Opportunities at Natural Gas Compressor Stations*. Environmental Protection Agency. Retrieved July 11, 2020, from https://www.epa.gov/sites/default/files/2017-07/documents/compressor_stations_razvilka_2008.pdf.

EIA, Residential Energy Consumption Survey 2015 (2018). Washington, DC; Energy Information Administration.

Smith, A. P., Richardson, S. D., Boyd, V. H., Bowers, R. L., Stuver, S. K., Lyman, S., LaFleur, C., & Perry, S. H. (2018, October 1). *Integrated component-specific measurements to develop emission factors for compressors and gas gathering lines*. Integrated Component-Specific Measurements to Develop Emission Factors for Compressors and Gas Gathering Lines (Technical Report) | OSTI.GOV. Retrieved November 11, 2021, from https://www.osti.gov/biblio/1475568.

Zimmerle, D., Vaughn, T., Bell, C., Bennett, K., Deshmukh, P., & Thoma, E. (2020). Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. Environmental Science & Technology, 54(18), 11506-11514. https://doi.org/10.1021/acs.est.0c01285

Zimmerle, D. J., Williams, L. L., Vaughn, T. L., Quinn, C., Subramanian, R., Duggan, G. P., Willson, B., Opsomer, J. D., Marchese, A. J., Martinez, D. M., & Robinson, A. L. (2015). Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science & Technology, 49(15), 9374-9383. https://doi.org/10.1021/acs.est.5b01669

Appendix A.

Weight	Cost	Robustness	Autonomy	Time series	Data quality
1	>40k	High risk	0%	sparse	Bad
2	<40K	Above Average	25%	Sort	Below Average
3	<30K	Average	50%	Moderate	Average
4	<20K	Below Average	75%	Long	Above Average
5	<10K	Low risk	100%	Continuous	Great

March 2021					Down Time	Rate Impact	Volume Impact			
Compressor	Sales Meter Affected	Unit(s)	Date Down	Restart Time	Hrs	MCFPD	MCF	Scheduling	Comments	Major Projects or AEP Power
Booster	2	41	3/3/21 9:26 AM	3/3/21 1:45 PM	4.3166667	50	8.993055555	Planned	Service also found bad head and changed out	No
Booster	2	45	3/3/21 2:02 PM	3/3/21 2:20 PM	0.3	54	0.675	Planned	Change suction valve stage 1 throw 3 headend 11oclock position	No

Appendix B.

G3516 LE

GAS ENGINE SITE SPECIFIC TECHNICAL DATA
USA Compression
G3516LE / WPW02566

CATERPILLAR®

GAS COMPRESSION APPLICATION

ENGINE SPEED (rpm):	1400
COMPRESSION RATIO:	8:1
AFTERCOOLER WATER INLET (°F):	130
JACKET WATER OUTLET (°F):	210
COOLING SYSTEM:	JW+OC, AC
IGNITION SYSTEM:	ADEM3
EXHAUST MANIFOLD:	ASWC
COMBUSTION:	Low Emission
NOx EMISSION LEVEL (g/bhp-hr NOx):	2.0
SET POINT TIMING:	33.0

FUEL SYSTEM:	HPG IMPCO WITH AIR FUEL RATIO CONTROL
SITE CONDITIONS:	
FUEL:	Gas Analysis
FUEL PRESSURE RANGE(psig):	35.0-40.0
FUEL METHANE NUMBER:	88.6
FUEL LHV (Btu/scf):	924
ALTITUDE(ft):	1600
MAXIMUM INLET AIR TEMPERATURE(°F):	90
NAMEPLATE RATING:	1340 bhp@1400rpm

			MAXIMUM RATING	SITE RATING AT MAXIMUM INLET AIR TEMPERATURE		
RATING	**NOTES**	**LOAD**	**100%**	**100%**	**75%**	**50%**
ENGINE POWER	(1)	bhp	1340	1340	1005	670
INLET AIR TEMPERATURE		°F	90	90	90	90
ENGINE DATA						
FUEL CONSUMPTION (LHV)	(2)	Btu/bhp-hr	7547	7547	7775	8326
FUEL CONSUMPTION (HHV)	(2)	Btu/bhp-hr	8372	8372	8624	9235
AIR FLOW	(3)(4)	lb/hr	12619	12619	9520	6566
AIR FLOW WET (77°F, 14.7 psia)	(3)(4)	scfm	2846	2846	2147	1481
INLET MANIFOLD PRESSURE	(5)	in Hg(abs)	70.9	70.9	55.9	39.8
EXHAUST STACK TEMPERATURE	(6)	°F	873	873	873	877
EXHAUST GAS FLOW (@ stack temp, 14.5 psia)	(7)(4)	ft3/min	7648	7648	5775	4004
EXHAUST GAS MASS FLOW	(7)(4)	lb/hr	13097	13097	9889	6830
EMISSIONS DATA						
NOx (as NO2)	(8)	g/bhp-hr	2.00	2.00	2.00	2.00
CO	(8)	g/bhp-hr	1.85	1.85	1.94	2.09
THC (mol. wt. of 15.84)	(8)	g/bhp-hr	2.63	2.63	2.76	2.95
NMHC (mol. wt. of 15.84)	(8)	g/bhp-hr	0.40	0.40	0.41	0.44
NMNEHC (VOCs) (mol. wt. of 15.84)	(8)(9)	g/bhp-hr	0.26	0.26	0.28	0.29
HCHO (Formaldehyde)	(8)	g/bhp-hr	0.26	0.26	0.27	0.29
CO2	(8)	g/bhp-hr	470	470	478	503
EXHAUST OXYGEN	(10)	% DRY	8.1	8.1	8.0	7.8
HEAT REJECTION						
HEAT REJ. TO JACKET WATER (JW)	(11)	Btu/min	42204	42204	35145	29034
HEAT REJ. TO ATMOSPHERE	(11)	Btu/min	5313	5313	4428	3543
HEAT REJ. TO LUBE OIL (OC)	(11)	Btu/min	6294	6294	5241	4330
HEAT REJ. TO AFTERCOOLER (AC)	(11)(12)	Btu/min	11095	11095	7184	2502

HEAT EXCHANGER SIZING CRITERIA			
TOTAL JACKET WATER CIRCUIT (JW+OC)	(12)	Btu/min	53977
TOTAL AFTERCOOLER CIRCUIT (AC)	(12)(13)	Btu/min	11650
A cooling system safety factor of 0% has been added to the heat exchanger sizing criteria.			

CONDITIONS AND DEFINITIONS
Engine rating obtained and presented in accordance with ISO 3046/1, adjusted for fuel, site altitude and site inlet air temperature.
100% rating at maximum inlet air temperature is the maximum engine capability for the specified fuel at site altitude and maximum site inlet air temperature.
Max. rating is the maximum capability for the specified fuel at site altitude and reduced inlet air temperature.
Lowest load point is the lowest continuous duty operating load allowed. No overload permitted at rating shown.

For notes information consult page three.

PREPARED BY: Doug Hillin, Warren CAT
Data generated by Gas Engine Rating Pro Version 3.04.00
Ref. Data Set DM8618-01-001, Printed 17Feb2011

Page 1 of 4

G3516 LE

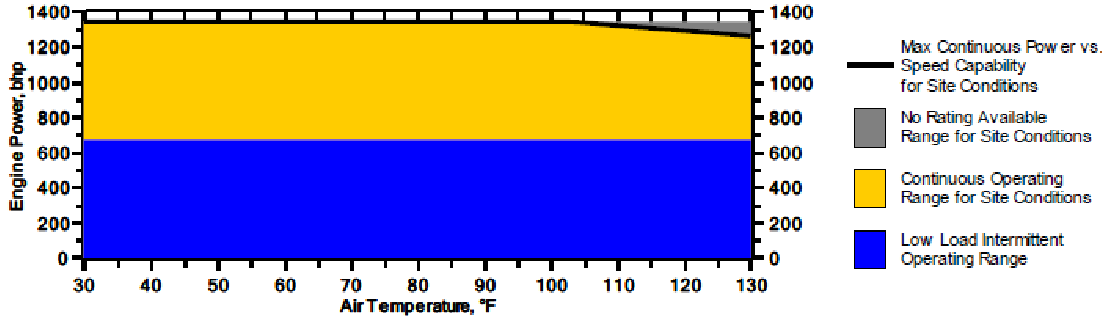
GAS COMPRESSION APPLICATION

GAS ENGINE SITE SPECIFIC TECHNICAL DATA
USA Compression
G3516LE / WPW02566

CATERPILLAR®

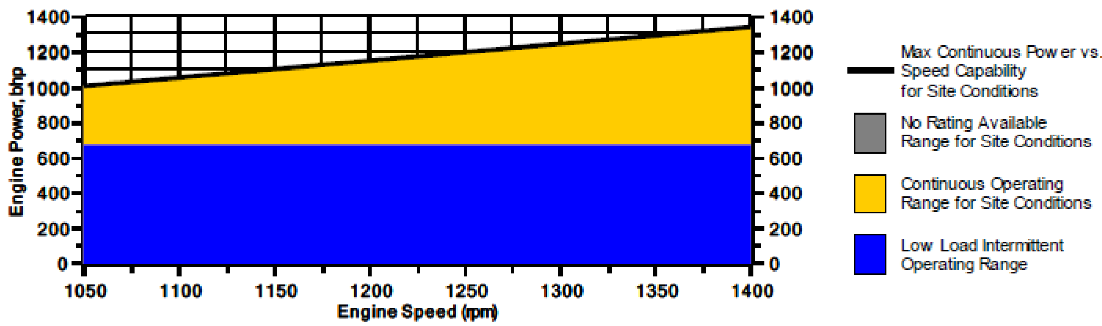
Engine Power vs. Inlet Air Temperature

Data represents temperature sweep at 1600 ft and 1400 rpm



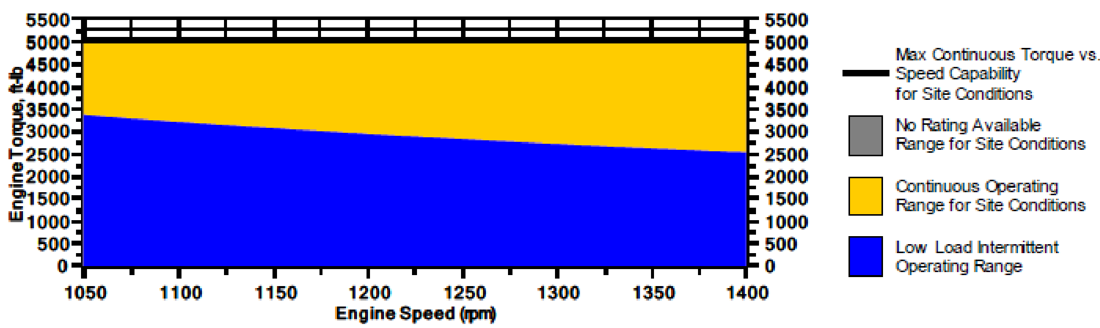
Engine Power vs. Engine Speed

Data represents speed sweep at 1600 ft and 90 °F



Engine Torque vs. Engine Speed

Data represents speed sweep at 1600 ft and 90 °F



Note: At site conditions of 1600 ft and 90°F inlet air temp., constant torque can be maintained down to 1050 rpm. The minimum speed for loading at these conditions is 1050 rpm.

PREPARED BY: Doug Hillin, Warren CAT
Data generated by Gas Engine Rating Pro Version 3.04.00
Ref. Data Set DM8618-01-001, Printed 17Feb2011

NOTES

1. Engine rating is with two engine driven water pumps. Tolerance is ± 3% of full load.

2. Fuel consumption tolerance is ± 3.0% of full load data.

3. Air flow value is on a 'wet' basis. Flow is a nominal value with a tolerance of ± 5 %.

4. Inlet and Exhaust Restrictions must not exceed A&I limits based on full load flow rates from the standard technical data sheet.

5. Inlet manifold pressure is a nominal value with a tolerance of ± 5 %.

6. Exhaust stack temperature is a nominal value with a tolerance of (+)63°F, (-)54°F.

7. Exhaust flow value is on a "wet" basis. Flow is a nominal value with a tolerance of ± 6 %.

8. Emission levels are at engine exhaust flange prior to any after treatment. Values are based on engine operating at steady state conditions, adjusted to the specified NOx level at 100% load. Fuel methane number cannot vary more than ± 3. Values listed are higher than nominal levels to allow for instrumentation, measurement, and engine-to-engine variations. They indicate "Not to Exceed" values. THC, NMHC, and NMNEHC do not include aldehydes. An oxidation catalyst may be required to meet Federal, State or local CO or HC requirements.

9. VOCs - Volatile organic compounds as defined in US EPA 40 CFR 60, subpart JJJJ

10. Exhaust Oxygen level is the result of adjusting the engine to operate at the specified NOx level. Tolerance is ± 0.5.

11. Heat rejection values are nominal. Tolerances, based on treated water, are ± 10% for jacket water circuit, ± 50% for radiation, ± 20% for lube oil circuit, and ± 5% for aftercooler circuit.

12. Aftercooler heat rejection includes an aftercooler heat rejection factor for the site elevation and inlet air temperature specified. Aftercooler heat rejection values at part load are for reference only. Do not use part load data for heat exchanger sizing.

13. Heat exchanger sizing criteria are maximum circuit heat rejection for the site, with applied tolerances.

Constituent	Abbrev	Mole %	Norm
Water Vapor	H2O	0.0000	0.0000
Methane	CH4	96.8678	96.8678
Ethane	C2H6	1.5989	1.5989
Propane	C3H8	0.1960	0.1960
Isobutane	iso-C4H1O	0.0299	0.0299
Norbutane	nor-C4H1O	0.0447	0.0447
Isopentane	iso-C5H12	0.0606	0.0606
Norpentane	nor-C5H12	0.0383	0.0383
Hexane	C6H14	0.0997	0.0997
Heptane	C7H16	0.0000	0.0000
Nitrogen	N2	0.7628	0.7628
Carbon Dioxide	CO2	0.2321	0.2321
Hydrogen Sulfide	H2S	0.0000	0.0000
Carbon Monoxide	CO	0.0000	0.0000
Hydrogen	H2	0.0000	0.0000
Oxygen	O2	0.0692	0.0692
Helium	HE	0.0000	0.0000
Neopentane	neo-C5H12	0.0000	0.0000
Octane	C8H18	0.0000	0.0000
Nonane	C9H20	0.0000	0.0000
Ethylene	C2H4	0.0000	0.0000
Propylene	C3H6	0.0000	0.0000
TOTAL (Volume %)		100.0000	100.0000

Fuel Makeup:	Gas Analysis
Unit of Measure:	English

Calculated Fuel Properties

Caterpillar Methane Number:	88.6
Lower Heating Value (Btu/scf):	924
Higher Heating Value (Btu/scf):	1025
WOBBE Index (Btu/scf):	1219
THC: Free Inert Ratio:	134.71
RPC (%) (To 905 Btu/scf Fuel):	100%
Compressibility Factor:	0.998
Stoich A/F Ratio (Vol/Vol):	9.65
Stoich A/F Ratio (Mass/Mass):	16.79
Specific Gravity (Relative to Air):	0.575
Specific Heat Constant (K):	1.313

CONDITIONS AND DEFINITIONS

Caterpillar Methane Number represents the knock resistance of a gaseous fuel. It should be used with the Caterpillar Fuel Usage Guide for the engine and rating to determine the rating for the fuel specified. A Fuel Usage Guide for each rating is included on page 2 of its standard technical data sheet.

RPC always applies to naturally aspirated (NA) engines, and turbocharged (TA or LE) engines only when they are derated for altitude and ambient site conditions.

Project specific technical data sheets generated by the Caterpillar Gas Engine Rating Pro program take the Caterpillar Methane Number and RPC into account when generating a site rating.

Fuel properties for Btu/scf calculations are at 60F and 14.696 psia.

Caterpillar shall have no liability in law or equity, for damages, consequently or otherwise, arising from use of program and related material or any part thereof.

FUEL LIQUIDS

Field gases, well head gases, and associated gases typically contain liquid water and heavy hydrocarbons entrained in the gas. To prevent detonation and severe damage to the engine, hydrocarbon liquids must not be allowed to enter the engine fuel system. To remove liquids, a liquid separator and coalescing filter are recommended, with an automatic drain and collection tank to prevent contamination of the ground in accordance with local codes and standards.

To avoid water condensation in the engine or fuel lines, limit the relative humidity of water in the fuel to 80% at the minimum fuel operating temperature.