Characterization of Methane Emissions from Gathering Compressor Stations: Final Report

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EXECUTIVE SUMMARY

This document is the final report to the U.S. Department of Energy (DOE) for contract DE-FE0029068 awarded to Colorado State University (CSU). CSU and subcontractor AECOM partnered with nine U.S. midstream operators to characterize emissions from natural gas gathering and boosting stations ("gathering stations") – a sector of the natural gas supply chain where few measurements have been made and little data are available for component emissions. Although there is overlap in the classes of equipment on gathering stations with those on production sites or transmission stations that have been measured recently, emissions are likely to differ for functional and operational reasons.

Partner companies provided the study team site access to gathering stations to (1) measure methane emissions and (2) collect activity data on equipment and operations. Field measurements were made at 180 facilities in 11 U.S. states during June-November 2017. Measured facilities were sampled from 1705 partner facilities located in 28 American Association of Petroleum Geologists (AAPG) basins. Measurements were made in basins representative of current U.S. production and facilities selected for measurement shared key characteristics in proportion to all partner facilities.

The principal deliverable of this study is a set of emission factors for components and major equipment at gathering stations. Leaker and population emission factors were developed for components, and population factors were developed for major equipment. All data was also incorporated into a model to produce a nationally representative estimate of emissions from gathering stations. Emission factors and model results are intended to inform the U.S. Environmental Protection Agency (EPA) greenhouse gas inventory (GHGI). Components were counted on 1002 major equipment units (compressors, dehydrators, separators, tanks, acid gas removal units, and yard piping). Emission measurements were made on 1948 major equipment units. Data from a parallel study performed by GSI Environmental Inc. under the same DOE funding program were also incorporated. Not all emission factors used in the national model were updated during this study. Categories were previous emission factors were used include pneumatic controllers, flaring,

blowdowns, and dehydrator vents.

The study included updates to component emissions, updated estimates of per-station and national methane emissions, and performed new long-duration measurements of pneumatic controllers. Key results:

Component emission factors: The field campaign supported a robust updating of emission factors for fugitive and vented emissions on components and major equipment. In general, the study indicates that study emission factors either agree with, or are larger than, current greenhouse gas reporting program (GHGRP) emission factors for the western U.S. and most GHGI emission factors, and are substantially larger than emission factors used by the GHGRP for the eastern U.S.

This study also developed and field-tested two measurement methods to better characterize emissions from unburned methane entrained in compressor engine exhaust ("combustion slip"). Combustion slip was measured on 102 individual compressor drivers at 51 gathering stations. Results from combustion slip measurements indicate emissions similar to emission factors from EPA AP-42 [1].

Pneumatic controller measurements: The study developed new methods to measure vented and fugitive methane emissions from gas-powered, pneumatically actuated valves and controllers. Long-term, direct measurements of pneumatic controller emissions were made on 72 pneumatic controllers (PCs) at 16 gathering stations; measurements averaged 76 hours in duration. New emission factors could not be developed due to measurement errors with the meters utilized for the study (see Section 4.3), and as a consequence, GHGRP emission factors were utilized to estimate pneumatic controller emissions in station and national estimates. However, the PC emissions data is still useful for a qualitative examination of pneumatic controller emissions [2]. In particular, these long-duration measurements provide insight into PC emissions behaviors that are not reflected in manufacturer's literature and have not been shown in prior studies. Recorded PC data shows a high degree of variability in operation over the course of hours or days – especially for intermittent vent PCs. Recordings also show an unexpectedly high occurrence of abnormal emission behavior –

25 of 40 intermittent vent controllers show abnormal behavior at some point during the recording, and 5 of 24 were emitting at higher than the low-bleed maximum of 6 scfh.

Station emissions: Although component fugitive and vented emission factors are higher, current GHGI estimates are based upon whole-station measurements made in a prior field campaign [3] and subsequent national model [4]. Relative to these prior studies, and by extension the GHGI, emissions at stations measured during the field campaign indicate a statistically lower national estimate. The current study drew a nationally-representative sample from a larger population of stations than the previous study (1705 stations versus ≈700 stations) while working with a larger group of industry partners (9 partners versus 4 partners), which raises confidence in the current study. While reasons cannot be definitively stated, likely causes of the lower methane emissions in this study are: (1) the previous study measured facilities with substantially higher throughput than the current study (39.5 [0.223 to 382] versus 19.7 [0.068 to 116] MMscfd whole gas); (2) the partner population in the previous study indicated a larger proportion of more complex stations – this study sampled 60% compression-only stations versus 30% in the previous study [3]; (3) the two studies utilized different measurement methods; and, (4) there may have been operational improvements to gathering stations during the intervening four years.

Across all stations, 38% [30% to 43%] of all emissions are due to combustion slip – the largest category of methane emissions. Since combustion slip is strongly related to operating engine horsepower, and throughput is also a function of operating engine horsepower, combustion slip is the principal driver of the correlation between throughput and emissions. Fugitive and vented emissions account for a similar emission rate, 24% [15% to 38%] from yard piping, 21% [16% to 28%] from other major equipment, and 11% [8.5% to 12%] from pneumatic controllers. The remaining emissions are due to flares and acid gas removal unit (AGRU) and dehydrator vents.

National estimates: To complete national estimates, the study utilized 319 per-basin GHGRP reports for gathering systems in 36 AAPG basins, including 15,895 reported compressors, and counts for other equipment, including gas pneumatic controllers, dehydrators, flares and other equipment.

Using GHGRP activity data and data collected in the field campaign, the study estimated 6,111 [5,852 to 6,377] stations nationally, which is statistically higher then the current GHGI estimate of 5,241 stations. However, the study's national model indicated emissions that are statistically – and substantially – lower than current GHGI estimates for the gathering & boosting sector – 1,292 [1,243 to 1,371] $Gg \cdot y^{-1} CH_4$ versus a GHGI estimate of 1,955.1 $Gg \cdot y^{-1} CH_4$. Reasons for this difference align with those for station emission estimates - updated mix, size and throughput of stations, more complete activity data for stations, better estimates for unmeasured emission sources, including unit and station blowdowns, and possibly improvements in operations at gathering stations since prior studies.

Results presented in this report are supported by several supplemental volumes which are cited throughout. Supplemental volumes are further supported by appendices, as cited within. In addition, results will be disseminated in three peer-reviewed publications, either released or currently in preparation.

1. Zimmerle et al.[5] – Emission factors, activity data, and national estimate of emissions from gathering stations.
2. Luck et al. [2] – Long duration pneumatic controller measurements.
3. Vaughn et al. [6] – Methane emissions from combustion slip; measurement methods and results.

ACKNOWLEDGMENTS

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STANDARD TERMINOLOGY

AAPG American Association of Petroleum Geologists

AGRU acid gas removal unit

BHFS Bacharach® HI FLOW® Sampler

CSU Colorado State University

DOE Department of Energy

EPA Environmental Protection Agency

ESD emergency shut-down

FTIR Fourier Transform Infrared

GHGI greenhouse gas inventory

GHGRP greenhouse gas reporting program

GRI Gas Research Institute

METEC Methane Emissions Technology Evaluation Center

mtCO2eq metric tons CO_2 equivalent

OGI optical gas imaging

T&S transmission and storage

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1 INTRODUCTION

1.1 Project Initiation

In 2016, the U.S. Department of Energy (DOE) Office of Fossil Energy issued a funding opportunity announcement (FOA) titled "Methane Emissions Mitigation and Quantification from Natural gas Infrastructure" driven by the President's 2014 Climate Action Plan, which included a strategy to reduce methane emissions [7, 8]. The FOA funded research for developing leak mitigation-focused technologies and improving estimates of methane emissions from midstream natural gas operations, with a focus on better characterization of regional variations in emissions. Colorado State University (CSU) was awarded funding under Area of Interest 2A to perform direct emission measurements at the device level to develop methane emission factors for all classes of equipment found on *gathering and boosting* stations (referred to as "gathering stations" in this work). To accomplish this, CSU partnered with the engineering firm AECOM to assist with planning, logistics, field work and analysis.

Nine midstream natural gas companies also acted as partners in the study, and are listed in the acknowledgment section of this report. Partners provided data about their operations and offered access to their sites and input on the methods used in the study. The selection of facilities for the study from all partner facilities is described in Section 3.1.

The study had two primary objectives:

- Collect data on equipment counts and types (activity data) of gathering stations.
- Perform component level leak measurements suitable for developing new emission factors.

Both of the above deliverables were focused on updating the U.S. Environmental Protection Agency (EPA) greenhouse gas inventory (GHGI), although the data may be of use longer term for other studies and updates to the EPA greenhouse gas reporting program (GHGRP).

In addition, the study also focused on two emission sources that are currently not well characterized for compressor stations:

- Unburned methane entrained in compressor engine exhaust ("combustion slip")
- Methane emissions from natural gas-powered pneumatic valve controllers ("pneumatic controllers" or "PCs").

1.2 Organization of This Report

This document is supported by three supplemental volumes which focus on:

S1 Pneumatics measurements

S2 Exhaust measurements

S3 Component, station and national emissions

References to supplemental volumes are made throughout this report in the form *SI S1-2.1*, which refers to supplemental volume 1 (Pneumatic measurements), chapter 2, section 1. Supplements also reference appendices, which provide detailed information on individual measurements or emission factors. Data in tabular files are referenced in the supplemental volumes by workbook sheet and/or file name. Additional protocol documents are attached for field and equipment measurement protocols. These are referenced, as appropriate, in the supplemental volumes.

This document is organized into three chapters:

- Overview and Background: provides an overview of gathering and boosting operations.
- Methods: describes measurement and analysis methods for fugitive and vented emissions, for long-duration pneumatic controller measurements, and for combustion slip measurements.
- Results: summarizes study findings for each measurement type.

2 OVERVIEW AND BACKGROUND

2.1 Gathering & Boosting Sector

The gathering and boosting ("gathering") sector of the U.S. natural gas industry is a midstream sector between production and processing or transmission sectors. The U.S. gathering sector includes several thousand gathering compressor stations[9] which compress, and in some cases upgrade[1], natural gas. Gathering stations are interconnected by more than 400,000 miles of gathering pipeline[10]. This study focuses on methane emissions at gathering stations; no measurements or analysis of pipeline emissions were completed. While some gathering systems also transport liquids (oil, condensate, or water), this study measured and analyzed only the infrastructure handling natural gas.

Gathering stations are generally built around gas compression equipment which receives gas from production well pads and compresses it for delivery to gas processing plants. Alternatively, in basins where natural gas can be sufficiently upgraded at gathering stations, gas is delivered directly to transmission or distribution systems. Stations also include separators, tanks, piping, fuel gas systems, and miscellaneous other equipment to support gas upgrading, compression, and station operations. Stations also typically include equipment to support the pipelines connected to the facility: "pigging" launchers and receivers (for pipe cleaning operations), blocking valves for pipeline and station isolation, meters, and other similar equipment. Stations which upgrade gas utilize dehydrators to remove water from field gas, and, if needed, acid gas removal units (AGRUs) to remove acid gases such as H_2S or CO_2, and other contaminants. Examples of typical equipment are shown in Figure 1.

For measurement purposes, this study defines a *gathering station* as all equipment within the fence – or other clearly marked boundary – surrounding the facility. Figure 2 shows a typical example. For this study, a gathering station includes all equipment inside the boundary except for

[1] Upgrading typically includes removing water (dehydration), and, in some locations, other impurities. It *does not* include separation of natural gas liquids or other hydrocarbon products, which is typically performed at natural gas processing plants.

Figure 1: Typical equipment found on gathering stations. Clockwise from top left: Compressor, separator, liquid storage tanks and dehydrator.

any co-located production wells, which are included in the production sector for emission purposes and were therefore excluded from measurement in this study.

2.2 Prior Work

The GHGI estimates greenhouse gas emissions from all sources in the U.S. For most sectors of the natural gas industry, the GHGI utilizes emission factors that have an activity basis of either major equipment counts or component counts. Emissions are calculated by multiplying emission factors by equipment or component counts. Recent studies have updated component and equipment emission factors for production [11, 12, 13], transmission and storage, [14], distribution [15], and other sectors. For each of these sectors, the GHGI typically develops activity data from annual reports of equipment counts to the GHGRP. Note that GHGRP data is reported only for facilities that exceed the reporting threshold for the sector, typically 25,000 metric tons CO_2 equivalent (mtCO2eq) per facility; *facility* is defined by sector and could refer to all of a company's operations in a production basin.

Figure 2: Typical gathering station shown in satellite imagery. Each station has a clearly delineated boundary, in this case defined by the gravel pad on the station.

However, for the gathering sector, the GHGI currently estimates a national station count and uses a per-station emission factor to estimate emissions. The national station count is based upon an analysis of air permit data performed by Marchese et al. [4], scaled by changes in natural gas production since the time of publication (2015). The per-station emission factor is based upon a field campaign conducted in 2013-14 [3], which measured approximately 115 gathering stations, and a national model developed in Marchese et al.

Beginning with reporting year 2016, the GHGRP required midstream operators to report activity data and emissions by American Association of Petroleum Geologists (AAPG) basin when emissions from their gathering operations are greater than 25,000 mtCO2eq in that basin. These data allow gathering sector emission estimates to be made at the major equipment or component-level instead of the station level, which could support updates to activity data year-over-year, and also enable a corresponding annual update of emissions estimates.

However, very few measurements have been made and little data are available on component-level emissions from equipment on gathering stations. The GHGRP uses component-level emission factors based on the results of a 1996 EPA/Gas Research Institute (GRI) [16] study that made measurements exclusively on well pads and gas production sites. Although there is overlap in the classes of equipment present on production and gathering stations, emissions are likely to differ for functional and operational reasons. Likewise, comparable equipment is utilized in the transmission and storage (T&S) sector, but T&S equipment-level emission factors are unlikely to be representative of gathering operations, due to the larger size of T&S equipment and differences in gas composition. This study directly addresses these deficiencies in emission factors.

The study also performed specialized measurements on two emission sources of interest: combustion slip and pneumatic controllers.

Combustion slip: The vast majority of compressors operating in the gathering sector (96% of compressors in the field campaign) are driven by natural gas powered engines. The remainder are powered by electric motors or turbines. A typical compressor skid is shown in Fig. 3. Engines are often tested for criteria pollutants, but are not typically tested for methane emissions. Methane emission factors for engines are published in the EPA Compilation of Air Emission Factors (AP-42)[1], stratified by the three common engine types used in the industry: four-stroke lean-burn, four-stroke rich-burn, and two-stroke lean-burn.

Results from recent studies [17, 18, 14] indicate that combustion slip can represent a significant fraction of emissions from facilities with operating engines. The gathering sector operates a large number and variety of engines, which may have different emission rates. While a fraction of these engines are routinely tested for permitted air pollutants, the full diversity of gathering engines has not previously been measured for methane emissions. This drove the interest in measuring a wide sample of engines and updating combustion slip factors for this sector. A novel in-stack tracer measurement method was developed for this study to quantify methane emissions more quickly than standard stack testing protocols. The method was used on a representative selection of engines, across operators and operating regions.

Pneumatic controllers: Automated, pneumatically-powered valves and actuators are used to control process variables (temperature, level, pressure and flow) on stations in all sectors of the

Figure 3: Typical skid-mounted compressor driven by a reciprocating natural gas engine in the gathering and boosting sector.

natural gas supply chain. Many of these control systems use natural gas to power actuators, as stations have a constant source of high pressure natural gas which eliminates the need for separate compression equipment to compress and dry ambient air. This is especially advantageous for remote stations without connections to electrical power, where additional natural gas engines would be needed to drive electric generators or air compressors. Figure 4 shows an example of a PC installation, including actuator and controlled valve.

By design, the majority of these pneumatic controllers (PCs) vent a portion of their supply gas to the atmosphere while pressurizing or de-pressurizing valve actuators. These emissions occur either continuously between control events ("continuous bleed") or in intermittent bursts ("intermittent bleed"), depending on the design and specific application of the PC. The EPA classifies PCs according to their normally operating vent behavior as intermittent or continuous bleed [19]. Continuous bleed devices are further classified as as low-bleed or high-bleed based on their steady state (inactive) emissions [20]; PCs that vent <6 scfh of gas are classified as low-bleed and those that vent ≥ 6 scfh of gas are classified as high-bleed. In addition to emissions from venting during

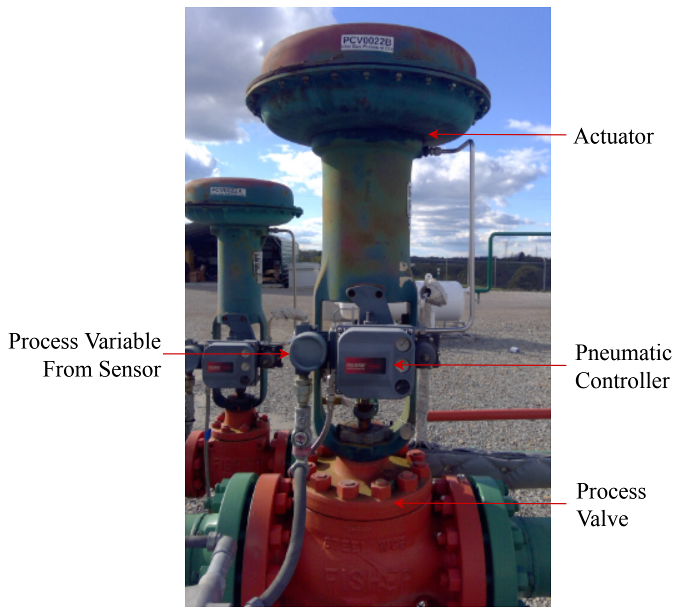


Figure 4: Example assembly of a PC, actuator and valve in pressure control service on a natural gas gathering station.

normal process control operation, some fraction of PCs may also emit gas through leaking tube fittings, valve stems, and damaged or malfunctioning controller components [2, 12, 15].

PC emission factors for the GHGRP are derived from the 1996 EPA/GRI study[16, 21], and a Canadian Petroleum Association emission rate study [22]. A relatively small data set was used to calculate these emission factors (41 continuous bleed controllers and 19 intermittent vent controllers). This single set of PC emission factors is used to estimate PC emissions from all sectors of onshore natural gas production.

These prior studies, along with more recent measurements [12, 11, 23, 24, 25], utilized short-duration (typically 15-minute) measurements of PCs in order to sample as many PCs as possible during the study. Short-duration measurements have a limited ability to capture normal actuation behavior or abnormally operating behaviors, which may exhibit complex emission patterns in time. To address knowledge gaps in previous studies and improve the characterization of PC emissions behavior, the measurement strategy in this study was focused on collecting continuous, long duration (3-4 day) direct measurements of PC emissions from a representative sample of devices. This approach limited the total number of PCs that could be measured, but improved the understanding of PC behavior.

3 METHODS

3.1 Sampling Plan

To develop robust emission factors for gathering stations, the study secured site access and performed measurements on a sample of stations representative of the U.S. gathering sector in terms of size, geographic distribution, gas composition, and equipment mix. Nine midstream natural gas companies acted as industry partners in this project and provided activity data for their gathering station assets (including station locations, station type, mix of engines, and gas composition) and access to their gathering stations during the study. A brief overview of the sampling strategy is provided here with more detail discussed in SI S3-1. Additional sampling details are discussed for pneumatic devices in SI S1-2 and for exhaust measurements in SI S2-1.

Prior to the field campaign, the nine partner companies provided a facility list for their gathering assets. These companies operate approximately 1705 gathering stations, with assets in 28 AAPG basins. These basins account for 85% of annual natural gas production in the U.S. Combined, the partner companies operate 35% of all compressor units reported to the GHGRP from the gathering sector in 2016.

A sample of stations was selected from the population of partner stations using a randomized clustered sampling strategy. To ensure anonymity for industry partners, only basins where at least two partner companies had operating assets were considered for the field campaign. Basins were selected from this population, ensuring that the selection was representative of national basin diversity in terms of gas composition (wet/dry) and age of production plays. Each basin from this final population was assigned one week of the field campaign. While most weeks were dedicated to measurements at stations from a single partner company, several weeks included measurements from more than one company [SI S3-1.1].

Five primary stations (one dedicated to each day of the week) were randomly selected from partner assets in each sampled basins. For each primary station, up to five nearest geographic neighbor stations were located and identified as secondary stations. While in the field, study teams first performed measurements and collected activity data each day at the assigned primary station. If time permitted, they then moved on to secondary stations in a pre-determined order. This method was executed over 19 field weeks, with measurements made at 180 gathering stations. The stratification by number of compressors (as a surrogate for station size) and station equipment mix of this final list of selected sites agreed with the stratification of all partner sites to within ±12% [SI Fig S3-2]. Figure 5 shows an example of a weekly campaign plan.

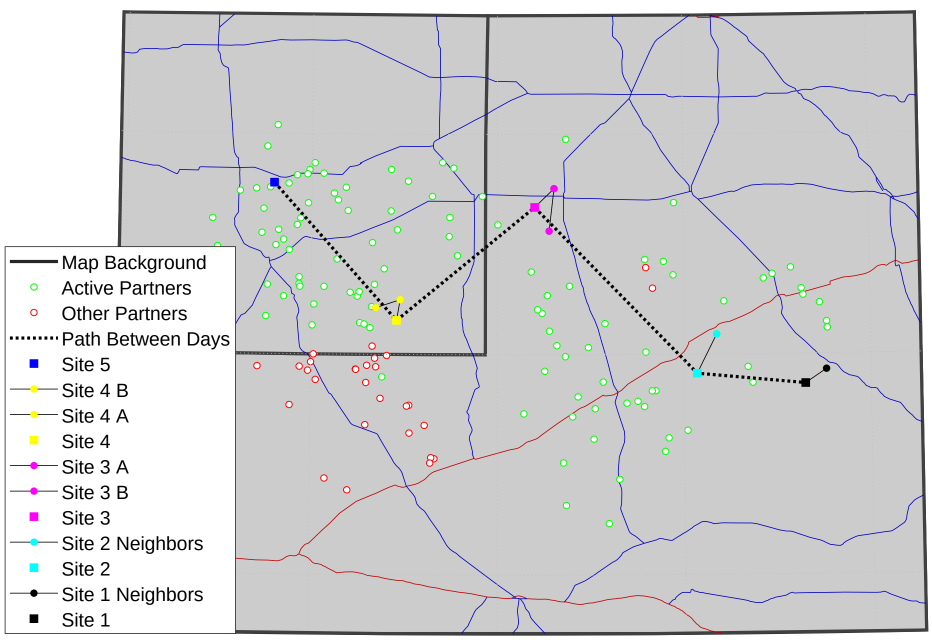


Figure 5: Example of a weekly campaign plan. Five stations were randomly selected from one partner's stations for the week. Stations were sorted in geographical order and assigned to a day, labeled *Site 1* to *Site 5*. Secondary stations were identified near each primary station. The number of secondary stations identified each day was adjusted for the size and complexity of the selected stations. For each measurement day, the primary station was measured first, followed by secondary (neighboring) stations, in a predetermined order, as time permitted.

Figure 6 shows the location of all field measurement locations, overlaid on county gas production data for 2017. Sampling occurred in counties across a wide range of gas production intensities, including counties with the highest gas production in the U.S. (Northeastern Pennsylvania). Locations also represent a wide range of station ages and configurations.

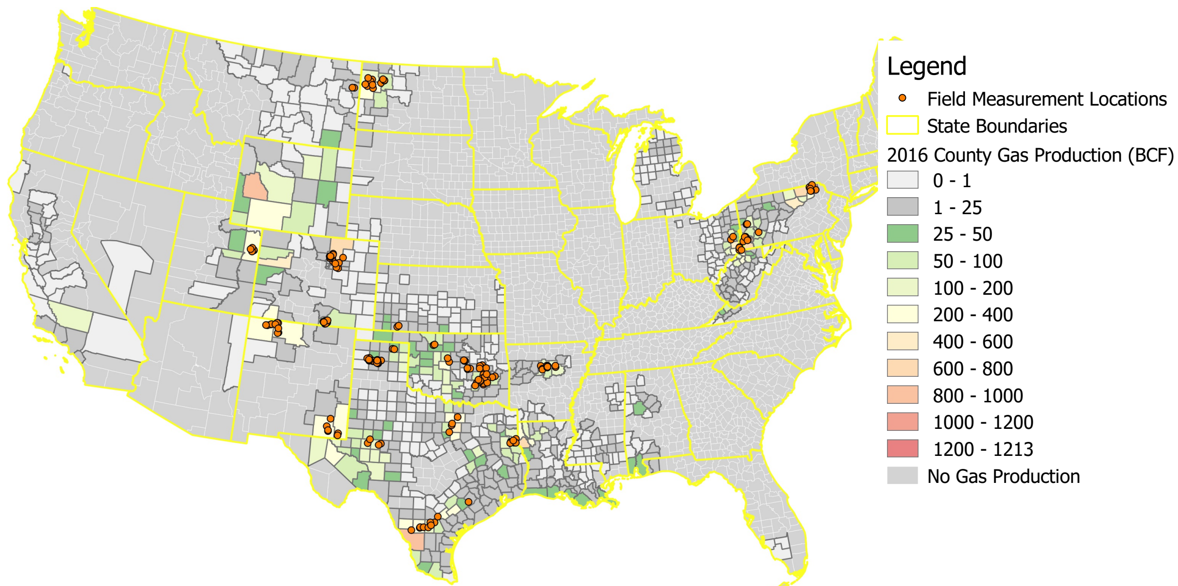


Figure 6: Location of all 180 stations included in the field study. Gas production by county is taken from Drilling Info™data. Points include stations measured by both field measurement teams.

Two teams of CSU and AECOM personnel were deployed during the field campaign (referred to a "Team 1" and "Team 2"). Each team was equipped with an optical gas imaging (OGI) camera, a Bacharach® HI FLOW® Sampler (BHFS) and anti-static measurement bags (often called "calibrated bags") for identifying and measuring fugitive or vented emissions. [SI S3-1.3] Team 1 was additionally equipped with thermal mass flow meters for performing multi-day emissions measurements from PCs and a Fourier Transform Infrared (FTIR) spectrometer for measuring combustion slip. Figure 7 shows the location of pneumatic controller and exhaust measurement locations.

Long-duration PC measurements were only performed on stations with gas-powered pneumatics. Since 27% of partner facilities use air-powered pneumatics (commonly called "instrument air"),

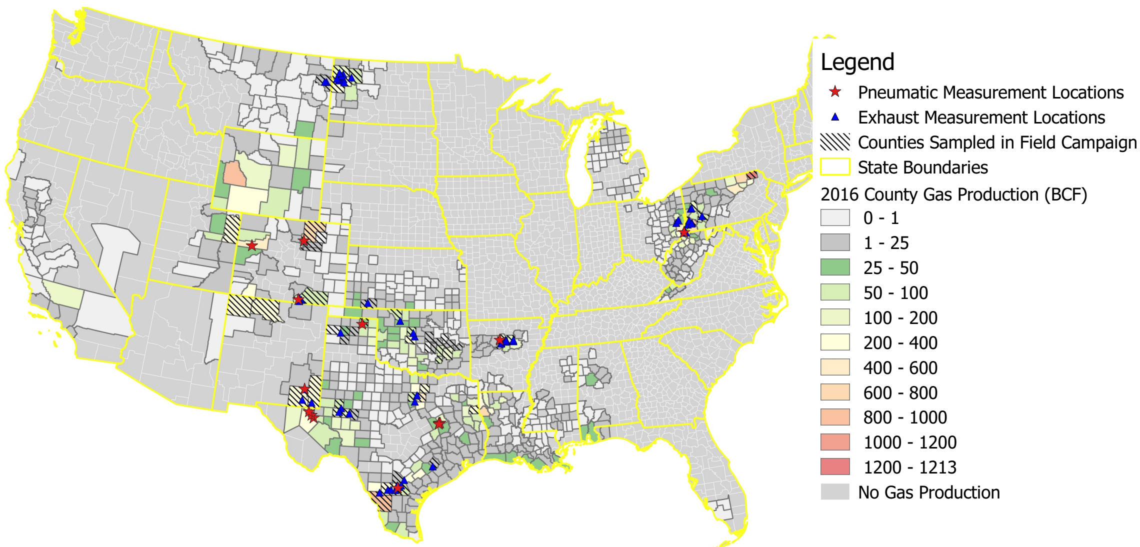


Figure 7: Location of the 15 stations where long-duration pneumatic and combustion slip measurements were performed. All counties included in the field study are shaded. Due to a higher-than-expected prevalence of instrument air on study stations, not all stations included in the measurement campaign could be used for pneumatic measurements. Gas production by county is taken from Drilling Info™data. All measurements were performed by "Team 1".

some weeks did not support pneumatic measurements.

3.1.1 Measuring Fugitive and Vented Emissions

For the purpose of developing major equipment and component level emission factors, units of major equipment were defined by the isolation valves upstream and downstream of the piece of equipment. Major equipment categories are:

- *Compressors:* Compressor skid or unit, includes a compressor driver (engine, turbine, motor) and the gas compressor.
- *Dehydrators*
- *Acid gas removal units (AGRU)*
- *Station separators:* Large separators not on other major equipment units. For example,

interstage knock-out tanks on compressors were considered part of the compressor, while inlet separators on the suction header of stations were counted as station separators.

- *Liquid storage tanks:* Storage tanks, not including tanks located on other major equipment units. All tanks were atmospheric pressure tanks; no pressurized tanks were measured in this field campaign.
- *Yard piping:* All other equipment on the station.

Screening and measurement of emissions were conducted by unit of major equipment. Not all major equipment units were screened for leaks on every station visited. Emission measurements were performed on as many units as time allowed. Equipment was only classified as measured if the entire unit was screened and all emissions found were recorded and attempted to be measured. Similarly, components were only counted on a subset of the major equipment units on each station [SI S3-1.5].

3.1.2 Combustion Slip Measurements

Only one of the two field teams deployed during the field campaign (Team 1) was equipped to perform compressor exhaust measurements. Therefore, all stations allocated to field Team 1 at the start of the field campaign were considered for measurement. Tests were performed at least at the primary station selected for each day. Additional engines were tested at secondary stations if time allowed. At a small set of stations, combustion slip measurements were performed in tandem with regularly scheduled compliance testing, and compared to validate this study's novel measurement method. In cases where combustion slip measurements were made concurrently with compliance tests, operating conditions required for compliance testing were used. In all other cases engines were measured "as found." Therefore, sampled engines provided combustion slip data across a wide range of operating conditions and loads typical of partner gathering operations.

Not all engines could be measured. Exceptions include:

- Access or safety issues
- Exhaust stack configuration did not provide an adequate tracer injection location [SI S2-2.2]
- Insufficient time to complete a test

3.1.3 Pneumatic Controller Measurements

Long-duration PC measurements were scheduled for the 11 field-weeks allocated to Team 1 during the field campaign. Each week, the first station assigned for measurement on Monday was utilized for long-duration measurements. Instrumentation was installed on Monday, left to collect data for 3-4 days – typically until battery power was exhausted – and retrieved by the study team on Friday. However, during detailed campaign planning (after sample weeks had been allocated), the study team discovered that the pneumatic controllers at 27% of partner sites were operated on compressed air (often called "instrument air"). From an emissions perspective, this is a positive development, as it eliminates vented and fugitive emissions from PCs entirely. Consequently, long-duration measurements could only be made during 8 of 11 field-weeks. To distiguish measurements made during the field campaign from measurements made after the field campaign, PCs measured by Team 1 while on the field campaign are classified as "Class I' in the data summaries.

Due to the prevalence of stations using instrument air for PCs, PC measurements were continued after the conclusion of the field campaign to increase the sample size and diversity. [see SI S1-1 for more description of the field campaign.] Partners were requested to provide basin locations for sampling. The extended sampling included 11 additional gathering stations in four basins. These stations were selected in collaboration with industry partners in areas not visited during the field campaign and *were not* randomly selected during the original site selection. Otherwise, the same protocol was utilized for the measurements.

During the post-campaign phase, CSU personnel traveled to the stations which had been selected for sampling. At the first station, CSU personnel were present for the meter installation and trained a designated partner technician on how to install and de-install the measurement equipment, charge batteries, and upload data; these stations are designated as "Class II" in the data tables. CSU personnel also traveled with the technician to all other stations which would be measured and finalized the selection of PCs to be measured; these stations are designated as "Class III" in the data tables. At the end of the measurement period on each station, the technician photographed the meter installation, uploaded data, recharged meters, and moved meters to the next designated location. Including all measurements, PC measurements were made at stations owned by eight of the nine partner companies participating in the study; all stations operated by the last partner utilized compressed air to operate pneumatic devices and therefore were not measured.

Measured PCs were selected on an opportunistic basis, subject to several constraints. First, to install the meter it was necessary to disconnect the supply gas lines temporarily. This was not an issue for on/off type controllers but posed issues when PCs needed to continuously throttle or maintain sensitive control parameters continuously. For sensitive control applications, some station equipment was taken off-line for meter installation, if possible. If not possible, an attempt was made to install the meter on the exhaust port of the PC. If neither method worked, the PC was not measured, and a different PC was selected.

Second, the focus of this study was on measuring PCs that control process variables. Therefore, emergency shut-down (ESD) and other station safety or isolation controllers – which rarely actuate – were not instrumented in this study.

Overall, the study team used engineering judgment to select controllers for measurement considering both the practicality of measurement while attempting to measure a representative population of PCs.

3.1.4 Additional Measurement Data

In addition to data collected during the field campaign, data from a contemporaneous study conducted by GSI Environmental Inc. was incorporated into the study data. The GSI study measured fugitive and vented emissions at four compressor stations four times over the course of a year.

Measurements were conducted similarly to Team 2 (SI S3-1.1) of the field campaign, and included component measurement using similar methods to the field campaign, but no measurements of combustion slip and no long-duration measurements of PCs. (SI S3-1.2)

To avoid over-representing these stations in the resulting data, data from each emission location was averaged if that location had been measured multiple times. The impact of absorbing these data on resulting emission factors is presented in SI Tables S3-1 and S3-2.

3.2 Measurement Methods

Measurement methods are subdivided into three sub-sections, covering fugitive and vented emissions, combustion slip, and long-duration pneumatic controller measurements.

3.2.1 Fugitive and Vented Emissions

This study used methods well established in previous research [18, 11, 15] to identify and quantify fugitive and vented emissions at the component level. Emissions were identified using OGI cameras (either Opgal™ EyeCGas® or FLIR ™ GF320®). Nearly all emission locations were measured using a BHFS [SI S3-1.3]. Locations that appeared to exceed the capacity of the BHFS were measured using an anti-static bag of known volume and recording the time it took for gas to fill the bag. [SI S3-1.3]

Post-campaign, and after the first revision of this report, new information came to light regarding methods required to correct measurement readings made using the BHFS [26]. The study team brought three of the six BHFS units utilized in the study to Methane Emissions Technology Evaluation Center (METEC) for further testing and developed new correction curves for all BHFS measurements (see SI S3-1.3). The "October 2019" version of this report reflects these updated corrections.

Lower detection limits of the OGI cameras were taken from previous experimental work by Ravikumar et al. [27] and specialized testing was completed to establish a lower detection limit for the BHFS. Both sets of tests were performed at the CSU METEC. [SI S3-1.3]

A total of 1262 successful measurements were made, 1153 using the BHFS, and 4 using anti-static bags. Data from the GSI study added another 174 measurements, made with similar techniques. After averaging, as discussed in Section 3.1.4, the GSI data resulted in the addition of 105 measurements to the study.

For this study, an exceptional effort was made to record and classify unsuccessful measurement attempts. After the field campaign, each unsuccessful measurement attempt was assigned a quality indicator that was used to estimate emissions when developing emission factors; a total of 231 such attempts were logged and classified, using the eight classifications discussed in SI S3-1.6. Five of the eight classifications represent measurements that could not be completed for environmental (e.g. weather) or mechanical (e.g. an inaccessible leak location) reasons. Emissions for these classifications were estimated using data from successful measurements. One classification, *OGI Non-detect* indicated measurements used to test the efficacy of the OGI screening method, and required no additional processing.

The remaining two classifications require further discussion. First, *incomplete capture* indicates that all of the emissions could not be captured by the BHFS during the measurement attempt. These emissions were estimated using other successful measurements and an estimate of the fraction of emissions not captured [SI S3-2.5].

The remaining classification, *exceeded capacity* indicates emission locations where the source was too large to be measured using the BHFS or anti-static bags. These emissions were estimated by developing several specialized emission factors using data from other studies [SI S3-4.2, Table S3-38]. The emission factors for large emitters were not included in component leaker or population factors to avoid unduly skewing the results of closely-coupled component emission factors [SI S3-2.4]. Large emitter emissions have substantial impact on major equipment emission factors, adding 70% - 83% to the impacted major equipment factors [SI Table S3-39]. However, since the majority of emissions are not contributed by fugitive and vented sources, the impact of large emitters on national emissions is substantially smaller – 26% [21% to 34%].

3.2.2 Compressor Engine Exhaust

The in-stack tracer method developed for this study was derived from EPA method ALT-012, "An Alternate Procedure For Stack Gas Volumetric Flow Rate Determination" [28]. This method involves injecting a tracer gas (the method recommends sulfur hexafluoride, SF_6) at a known flow rate into an exhaust system, and estimating the total stack flow based on the dilution of the tracer gas. This requires that the tracer gas is injected far enough upstream of the exhaust outlet to ensure the tracer gas and exhaust stream are well-mixed, and also requires a tracer gas does not dissociate at the exhaust temperature or react with the exhaust gases. The tracer gas concentration measured at the exhaust outlet can be used to estimate the total exhaust stack flow rate, and the flow rate of any other exhaust gas species measured at the stack outlet. Figure 8 shows typical locations for tracer injection and exhaust measurement.

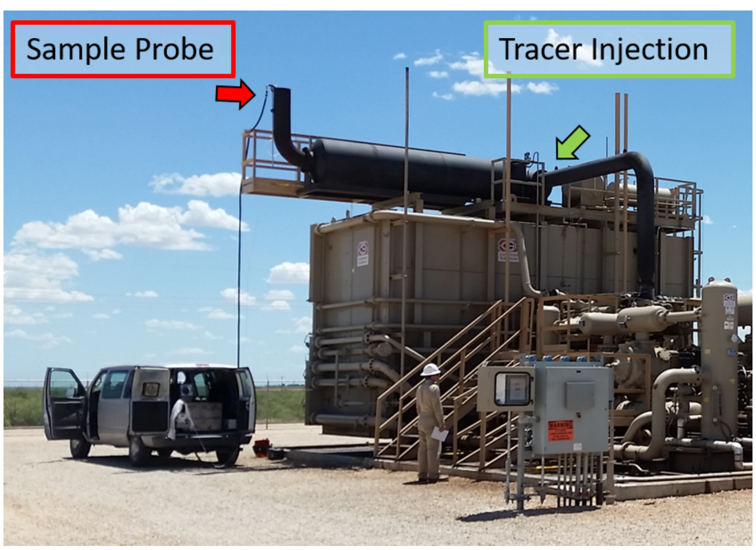


Figure 8: Example in-stack tracer measurement setup. Tracer gas is injected into the exhaust system upstream of the silencer. The tracer is mixed with exhaust gases in transit through the silencer and related piping. Well-mixed tracer and exhaust gases are collected at the sample probe and delivered through heated sample lines to an FTIR spectrometer in the van. The van also contains the tracer gas bottle and mass flow controller.

Due to the high temperature of rich burn engine exhaust, the study method utilized CF_4 (R14 Tetrafluoromethane 99.99%, Airgas Inc.) as a tracer gas, rather than SF_6, which may break down at rich burn exhaust temperatures. During testing, CF_4 was injected into the exhaust system through an available port or directly into the exhaust using a calibrated mass flow controller (Alicat Scientific, MCM-5SLPM-D). Choice of the tracer injection location varied depending upon the stack configuration, available injection ports, and accessibility and condition of the ports. Engine exhaust (including tracer) gas was collected near the exit of exhaust stacks using stainless steel probes and a heated sample line. Multi-port probes with holes at 16.7%, 50%, and 83.3% of the stack diameter were used in stacks with diameters $\geq$6 in. For smaller stacks ($<$6 in), single-point sample probes were used. Speciation was performed using an MKS Multigas 2030 FTIR spectrometer.

To validate the method, testing was performed on seven engines while a third party stack testing company was also testing the engine using standard methods, as described in Section 4.2.1.

3.2.3 Pneumatic Controller Emissions

Six thermal dispersion mass flow meters, also known as "hot wire" meters, were used during the study to quantify emissions from PCs. The measurement system used was adapted from methods used in previous studies [25, 23]. Several modifications were made, including: independent power supplies with an average 76-hour battery life to facilitate continuous multi-day measurements on remote stations without power connections; integrated data logging capability; and more robust safety certifications (Class I/Div I), for unsupervised operation in areas where explosive gases were present during normal operation.

Emissions from PCs were measured by connecting the meters to PC vent ports or in-line with PC supply gas lines [SI S1-3.3]. Connections to supply gas lines were used whenever possible, as this configuration reliably measures all gas supplied to the control loop. Connections at vent ports were only used when connections to supply gas lines could not be made for safety or operational reasons (see Section 3.1.3). Connections at vent ports only capture emissions from a single point

Figure 9: Emission measurement system installed on supply gas line to PC controlling liquid level in a secondary liquids storage tank.

in the control loop and do not capture emissions from other potential leak points in the system. Schematics of each of these connections are shown in SI Figures S1-2 and S1-3.

4 RESULTS AND DISCUSSION

4.1 Fugitive and Vented Emission Factors

The principal deliverable of this study is a set of emission factors for components and major equipment at gathering stations. Emission factors are summarized below and in Zimmerle et al. [5]. This study emphasized the development of complete emission factors – i.e. emission factors that account for all fugitive and vented emissions on major equipment units in the principal categories used at gathering stations - AGRUs, compressors, dehydrators, separators, tanks and yard piping. The GHGI will likely utilize GHGRP data, where activity data is primarily reported at the major equipment level, as the primary source of activity data for the GHGI estimates. Therefore, for

GHGI purposes, or for other inventories utilizing the GHGRP activity data, it is likely better to utilize major equipment counts and emission factors for each type of major equipment.

In addition to major equipment factors in Section 4.1.3, Sections 4.1.1 and 4.1.2 discuss emission factors at the component-level. A discussion of component emission factors provides a basis for comparison to prior studies that focused on component factors. In addition, component factors can be utilized to adjust major equipment factors as needed if major equipment configurations change substantially. Note that this study did not update pneumatic controller emission factors for gathering stations, for reasons described in Section 4.3.

Component emission factors are provided using a component classification similar to that used in the T&S sector [14]. Prior experience has shown that components on compressor skids tend to have different, typically larger, emission rates than components in service on other equipment at a compressor station [29, 18]. Therefore, two emission factors are provided for common components, divided into "compressor service" and "non-compressor service" classifications. For some component categories, additional work was performed to determine if emission factors should be subdivided or combined; see SI S3-2.1 to S3-2.3 for additional details.

Emission factors are provided for both whole gas and methane at standard conditions, in cubic feet per hour (scfh). Calculation of standard conditions is described in SI S3-1.7.

Finally, no emissions were detected for two component categories during the field campaign, shown in Table 1. Since it is unlikely that these components would have *no* emissions as a general rule, no emission factor is provided, and the emission factor for "other" components would be appropriate for estimating emissions from these components.

Table 1: Component Categories with No OGI Detections or Measurements

Component Category	Number of Components Counted
Gauge	1859
Meter	618

4.1.1 Leaker Emission Factors

Leaker emission factors represent emission rates expected from a component category *if* emissions are detected during a leak detection screen using an OGI camera or a similar screening method. In use, leaker factors are utilized when a station has been screened for leaks – emissions are calculated by multiplying the count of identified leaks by the appropriate leaker emission factor [SI S3-2].

Tables 2 and 3 summarize the leaker emission factors for whole gas and methane, respectively. Emission factors are grouped by the service categories. The *other* service category includes emission factors where there was insufficient data to develop separate factors for each service category. These factors may be utilized for any service type.

Leaker factors include estimates for emissions which could not be completely captured by the measurement methods, but do not include estimates for *large emitters*, which are only included in the major equipment factors. [SI S3-2.5] The number of simulated emission points in each emission factor is provided in the column *Number Simulated*. Finally, the last column of the table indicates the fraction of emissions caused by the largest 5% of emission locations. The column is blank if there were fewer than 20 measured leaks. This is a measure of the skew (also called "long tail") of the emissions distribution. For most leaker factors, 50% or more of emissions are due to the largest 5% of emitters.

Table 2: Whole Gas Leaker Emission Factors

Component	Number Measured	Number Simulated	Emission Factor (scfh whole gas)	Confidence Interval (scfh whole gas)	Fraction of Emissions Due to Largest 5% of Emitters
Non-compressor service					
Connector Flanged	31	1	7.88	[+42%/-36%]	18%
Connector Threaded	82	0	5.77	[+31%/-28%]	25%
PRV	23	0	10.8	[+123%/-80%]	54%
Regulator	43	0	8.01	[+33%/-30%]	18%
Valve	99	0	7.89	[+46%/-37%]	38%
Compressor service					
Connector Flanged	41	1	12.2	[+57%/-40%]	33%
Connector Threaded	107	5	14.5	[+52%/-38%]	47%
PRV	35	1	21.2	[+82%/-57%]	43%
Regulator	37	0	13.9	[+38%/-32%]	21%
Valve	39	1	41.1	[+109%/-64%]	58%
Common Multi-Unit Vent	13	0	66	[+86%/-71%]	
Common Single-Unit Vent	23	0	76	[+52%/-45%]	20%
Blowdown Vent	30	1	21.3	[+150%/-70%]	59%
Pocket Vent	23	0	7.81	[+80%/-61%]	34%
Rod Packing Vent	390	7	28.2	[+37%/-24%]	46%
Starter Vent	21	0	296	[+193%/-96%]	86%
Rod Packing Vent (OP)	366	7	28.5	[+35%/-24%]	47%
Rod Packing Vent (NOP)	17	0	23	[+65%/-49%]	
Rod Packing Vent (NOD)	7	0	11.5	[+42%/-37%]	
Tank service					
Common Multi-Unit Vent	15	0	119	[+90%/-68%]	
Common Single-Unit Vent	42	2	48.4	[+86%/-58%]	45%
Thief Hatch	65	0	30.1	[+54%/-41%]	41%
Other					
OEL	23	0	5.58	[+67%/-51%]	31%
Other	42	1	24	[+67%/-49%]	44%
Pump	12	2	35.5	[+74%/-53%]	

Table 3: Methane Leaker Emission Factors

Component	Number Measured	Number Simulated	Emission Factor (scfh CH_4)	Confidence Interval (scfh CH_4)	Fraction of Emissions Due to Largest 5% of Emitters
Non-compressor service					
Connector Flanged	31	1	6.46	[+41%/-37%]	19%
Connector Threaded	82	0	4.94	[+31%/-28%]	25%
PRV	23	0	9.56	[+124%/-82%]	57%
Regulator	43	0	6.49	[+35%/-32%]	20%
Valve	99	0	6.68	[+49%/-37%]	39%
Compressor service					
Connector Flanged	41	1	9.14	[+56%/-39%]	32%
Connector Threaded	107	5	12.1	[+52%/-38%]	49%
PRV	35	1	18.1	[+92%/-58%]	45%
Regulator	37	0	10.9	[+35%/-32%]	19%
Valve	39	1	36.3	[+120%/-68%]	60%
Common Multi-Unit Vent	13	0	57.3	[+84%/-69%]	
Common Single-Unit Vent	23	0	59.8	[+49%/-43%]	20%
Blowdown Vent	30	1	15.7	[+145%/-70%]	60%
Pocket Vent	23	0	6.35	[+69%/-58%]	28%
Rod Packing Vent	390	7	24.4	[+35%/-25%]	49%
Starter Vent	21	0	289	[+190%/-97%]	88%
Rod Packing Vent (OP)	366	7	24.9	[+35%/-26%]	50%
Rod Packing Vent (NOP)	17	0	20.1	[+69%/-50%]	
Rod Packing Vent (NOD)	7	0	9.27	[+40%/-39%]	
Tank service					
Common Multi-Unit Vent	15	0	109	[+100%/-73%]	
Common Single-Unit Vent	42	2	43.7	[+86%/-60%]	46%
Thief Hatch	65	0	25.9	[+61%/-45%]	44%
Other					
OEL	23	0	4.52	[+67%/-51%]	30%
Other	42	1	20.6	[+70%/-51%]	46%
Pump	12	2	26.8	[+79%/-56%]	

4.1.2 Population Emission Factors

Population, or *average*, emission factors represent the distribution of emission rates common to a component type or category. In use, emissions are estimated by multiplying a count of all components of one type by the population factor for that component type. Development of population factors utilizes the same measured emissions data as leaker emission factors: measured emissions are divided by the number of components screened during the field campaign.

Two factors needed to be considered when developing population factors [SI S3-3]:

1. *Complete component counts:* During the field campaign, emissions were screened and measured on one sample of major equipment units, while components were counted on a different

sample of major equipment units. This allowed field teams to balance leak measurement and counting activities, and in the case of component counting, assure that a sufficient sample of each type of major equipment was counted. Therefore, screened and measured units were not necessarily counted, and vice versa. If a unit was screened and measured, but not counted, the total component count on that unit was estimated by using the component counts from other similar units. [SI S3-3.1]

2. *Detected but unmeasured emissions:* As noted earlier, some detected emissions could not be measured. For population emission factors, these emission sources were estimated by using the leaker emission factor for the component. The lone exception to this rule is for large emitters (measurement quality indicator *exceeded capacity*); these emitters were not included in component emission factors for reasons discussed in SI S3-4.2.

All leaker factors do not have a corresponding population factor, as will be evident by comparing Table 2 with Table 4. This occurs when the underlying component count was incomplete or was not performed during the field campaign, and could not be estimated from other information.

Component counts for each component, on each type of major equipment, are provided in SI S3-3.4, Tables S3-30 to S3-35. These tables also compare component counts to those developed in the EPA/GRI 1996 study [16]. Compared to that study, we find that component counts in this study tend to be substantially larger than those from the eastern U.S. and often smaller than those from the western U.S. This disagreement indicates that equipment surveyed in the EPA/GRI study, which focused on well pads and associated equipment, was substantially different from gathering station equipment utilized today.

Population factors are summarized in Table 4 for whole gas and Table 5 for methane. Service categories are the same as discussed for leaker emission factor (Section 4.1.1). *Activity basis* indicates the correct component count to use with each emission factor. For example, the blowdown vent emission factor assumes there is one blowdown vent stack for each compressor. Therefore, compressor count, rather than blowdown stack count, should be used as the activity basis for the emission factor. The categories are:

- *Counted Components:* A count of components was performed, as described above, on a statistically significant sample of major equipment units.
- *One per Compressor:* Component was not counted; we assume there is one component on each compressor skid.
- *Compressor Cylinders:* Component was not counted; we assume that each pocket vent is separately vented.
- *One per Tank:* Most tanks have several vents or outlets that can potentially be open to atmosphere, making counting and classification difficult. Section S3-2.1 discusses the type of vents seen during the field campaign and how single- and multi-tank vents were classified and modeled.

Mean population for each emission factor indicates the number of components screened during the field campaign - i.e. the count of components which *could* have been leaking. For non-compressor service, component counts include all major equipment that is not a compressor skid, i.e. all components on AGRUs, dehydrators, separators, and yard piping. Tank counts were not included, see SI S3-1.5.

Table 4: Whole Gas Average Emission Factors

Component	Activity Basis	Mean Population	Emission Factor (scfh WholeGas)	Confidence Interval (scfh WholeGas)
Non-compressor service				
Connector Flanged	Counted Components	12,290	0.0213	[+17%/-14%]
Connector Threaded	Counted Components	38,696	0.0127	[+12%/-11%]
PRV	Counted Components	1,067	0.279	[+50%/-22%]
Regulator	Counted Components	608	0.626	[+23%/-19%]
Valve	Counted Components	9,981	0.091	[+28%/-23%]
Compressor service				
Connector Flanged	Counted Components	30,964	0.0186	[+25%/-14%]
Connector Threaded	Counted Components	60,419	0.0308	[+31%/-20%]
PRV	Counted Components	1,698	0.54	[+44%/-25%]
Regulator	Counted Components	658	0.781	[+15%/-14%]
Valve	Counted Components	10,204	0.169	[+38%/-18%]
Common Multi-Unit Vent	One per Station	140	7.2	[+36%/-23%]
Common Single-Unit Vent	One per Compressor	433	4.19	[+22%/-14%]
Blowdown Vent	One per Compressor	416	0.614	[+126%/-22%]
Pocket Vent	Compressor Cylinders	1,506	0.135	[+30%/-17%]
Rod Packing Vent	One per Compressor	412	27.7	[+25%/-11%]
Starter Vent	One per Compressor	426	16.7	[+78%/-31%]
Rod Packing Vent (OP)	One per Compressor	431	25.2	[+25%/-11%]
Rod Packing Vent (NOP)	One per Compressor	435	1.14	[+39%/-28%]
Rod Packing Vent (NOD)	One per Compressor	434	0.15	[+18%/-20%]
Tank service				
Common Multi-Unit Vent	One per Station	127	15.9	[+40%/-27%]
Common Single-Unit Vent	One per Tank	246	5.35	[+33%/-17%]
Thief Hatch	One per Tank	240	8.05	[+9.4%/-9.3%]
Other				
OEL	Counted Components	476	0.294	[+30%/-21%]

Table 5: Methane Average Emission Factors

Component	Activity Basis	Mean Population	Emission Factor (scfh CH4)	Confidence Interval (scfh CH4)
Non-compressor service				
Connector Flanged	Counted Components	12,290	0.0174	[+16%/-14%]
Connector Threaded	Counted Components	38,696	0.0108	[+13%/-11%]
PRV	Counted Components	1,067	0.243	[+48%/-22%]
Regulator	Counted Components	608	0.504	[+22%/-19%]
Valve	Counted Components	9,981	0.0772	[+28%/-24%]
Compressor service				
Connector Flanged	Counted Components	30,964	0.014	[+23%/-14%]
Connector Threaded	Counted Components	60,419	0.0254	[+29%/-19%]
PRV	Counted Components	1,698	0.459	[+51%/-28%]
Regulator	Counted Components	658	0.613	[+16%/-13%]
Valve	Counted Components	10,204	0.15	[+46%/-18%]
Common Multi-Unit Vent	One per Station	140	6.24	[+34%/-23%]
Common Single-Unit Vent	One per Compressor	433	3.21	[+21%/-14%]
Blowdown Vent	One per Compressor	416	0.44	[+129%/-23%]
Pocket Vent	Compressor Cylinders	1,506	0.109	[+26%/-16%]
Rod Packing Vent	One per Compressor	412	24.3	[+26%/-11%]
Starter Vent	One per Compressor	426	16.6	[+81%/-31%]
Rod Packing Vent (OP)	One per Compressor	431	22.1	[+25%/-12%]
Rod Packing Vent (NOP)	One per Compressor	435	0.988	[+40%/-29%]
Rod Packing Vent (NOD)	One per Compressor	434	0.117	[+17%/-22%]
Tank service				
Common Multi-Unit Vent	One per Station	127	14.7	[+40%/-27%]
Common Single-Unit Vent	One per Tank	246	4.8	[+34%/-18%]
Thief Hatch	One per Tank	240	6.94	[+10%/-10%]
Other				
OEL	Counted Components	476	0.238	[+31%/-21%]

4.1.3 Major Equipment Fugitive and Vented Emission Factors

Major equipment emission factors estimate the distribution of fugitive and vented emissions from major equipment units. The major equipment factors from this study include estimates for all emissions detected in the field campaign, including estimates for large emitters [SI S3-4.2], which are not included in component leaker or population factors. Construction of the factors is detailed in SI S3-4.1.

Categories selected for major equipment match component major equipment units reported to the GHGRP for the gathering and boosting sector. Using that structure, major equipment factors include all fugitive emissions, and selected vented emissions for sources which may have both fugitive and vented emissions. In general, the emissions represented by these factors are fugitive emissions (i.e. leaks), with the exception of two categories:

- *Rod packing vents:* Since most compressors were measured while pressurized and operating, emissions from rod packing vents are *vented*, i.e. expected, emissions, although the rod packing on some compressor cylinders may be venting more than manufacturer's specifications.
- *Tank vents:* For uncontrolled tanks, tank vents are primarily used to vent flash gas from liquids in the tank. However, leaks in upstream equipment, such as dump valves on separators, may malfunction and leak gas that is eventually routed to, and emitted from, tank vents. For controlled tanks, all emissions should be routed to a flare or vapor recovery unit, and any measured emissions are fugitive, i.e. unintended.

To estimate all emissions, the major equipment emission factors must be augmented by several remaining emission sources:

- Combustion slip is tracked separately as per common inventory practice; it is not included in compressor emissions.
- Fugitive and vented emissions from pneumatic controllers; as per common practice for GHGI and GHGRP, pneumatic controllers are not included as part of the major equipment where they are located.
- Dehydrator still vents
- AGRU vents
- Uncombusted methane in flare emissions
- Unit and station blowdown events. These emissions occur through the same vent locations as the fugitive emissions discussed earlier, but are classified as specific events, and the emissions are typically estimated using engineering calculations.

Emission factors are summarized in Table 6 for whole gas and Table 7 for methane. The activity basis of each emission factor is typically a unit of major equipment, i.e. one compressor or one dehydrator. Tank emissions are on a per-tank basis, not tank battery. There is one unit of yard piping per station, regardless of the station size. The wide confidence interval reflects the range of yard piping complexity, size and emissions behavior across the stations measured in the field campaign. The mean population for each emission factor is the number of units measured during the field campaign. The AGRU factor is statistically weak, with wide confidence intervals, due to the small number of units encountered in the campaign. [SI S3-4.3]

The number of emission sources is summarized in the last three columns of the table, including the mean and maximum number of sources on any one unit. A substantial number of units had no detected emission sources, from a low of 20% of compressors to over half of all AGRUs, dehydrators, and separators. Approximately half of all stations had no detected emissions on the station's yard piping.

Table 6: Major Equipment Whole Gas Emission Factors

Category	Activity Basis	Mean Population	Emission Factor (scfh whole gas)	Confidence Interval (scfh whole gas)	Mean Sources per Unit	Fraction of Units with No Sources	Maximum Sources per Unit
AGRU[1]	Unit	8	4.04	[+264%/-99%]	0.5	63%	2
Compressor	Unit	435	110	[+78%/-44%]	2.69	20%	18
Dehydrator	Unit	124	3.41	[+76%/-59%]	0.532	74%	6
Separator	Unit	326	0.647	[+78%/-53%]	0.153	90%	6
Tank	Tank	251	39.3	[+130%/-62%]	0.793	44%	4
YardPiping	Station	157	86.3	[+265%/-80%]	1.9	48%	17

[1] Emission factor is based upon few measurements and is unlikely to be robust.

Table 7: Major Equipment Methane Emission Factors

Category	Activity Basis	Mean Population	Emission Factor (scfh CH_4)	Confidence Interval (scfh CH_4)	Mean Sources per Unit	Fraction of Units with No Sources	Maximum Sources per Unit
AGRU[1]	Unit	8	3.61	[+274%/-99%]	0.5	63%	2
Compressor	Unit	435	94.4	[+77%/-46%]	2.69	20%	18
Dehydrator	Unit	124	2.95	[+77%/-59%]	0.532	74%	6
Separator	Unit	326	0.545	[+79%/-54%]	0.153	90%	6
Tank	Tank	251	33.6	[+120%/-61%]	0.793	44%	4
YardPiping	Station	157	74.4	[+238%/-80%]	1.9	48%	17

[1] Emission factor is based upon few measurements and is unlikely to be robust.

4.2 Combustion Slip: Methane in Compressor Engine Exhaust

This section briefly discusses combustion slip measurements. Additional detail is provided in SI Volume 2, and in Vaughn et al. [6].

4.2.1 Method Validation

First, the accuracy of the FTIR used to measure exhaust gas species composition was also periodically checked against known standards over the course of the field campaign [SI S2-2.3].

Several gathering station visits were arranged to coincide with third-party engine compliance testing. At these stations, the CSU study team performed exhaust measurements concurrently with stack testing contractors on seven compressor drivers. As a result, direct comparisons between stack flows predicted by the in-stack tracer method could be made to EPA Method 2 predictions on those seven units.

Exhaust stack flow estimates from the in-stack tracer method were compared to EPA Method 2 stack flow estimates using the Bland-Altman difference method and variance weighted, least-squares regression. Total stack flows estimated by the two methods were found to agree when compared by these methods.

The results of in-stack tracer measurements on 42 engines were also compared with the expected stack flows from manufacturer data sheets and manufacturer-provided software programs as an additional evaluation of the accuracy of the in-stack test method. This check could only be performed against newer engines equipped digital or analog readouts that allowed the study team to collect operating data on the engine (such as load percent, engine RPM and exhaust manifold pressure). In general, the total stack flows for both 4SLB and 4SRB engines agree with manufacturer specifications as shown in Figure 10 and in SI S2-4.

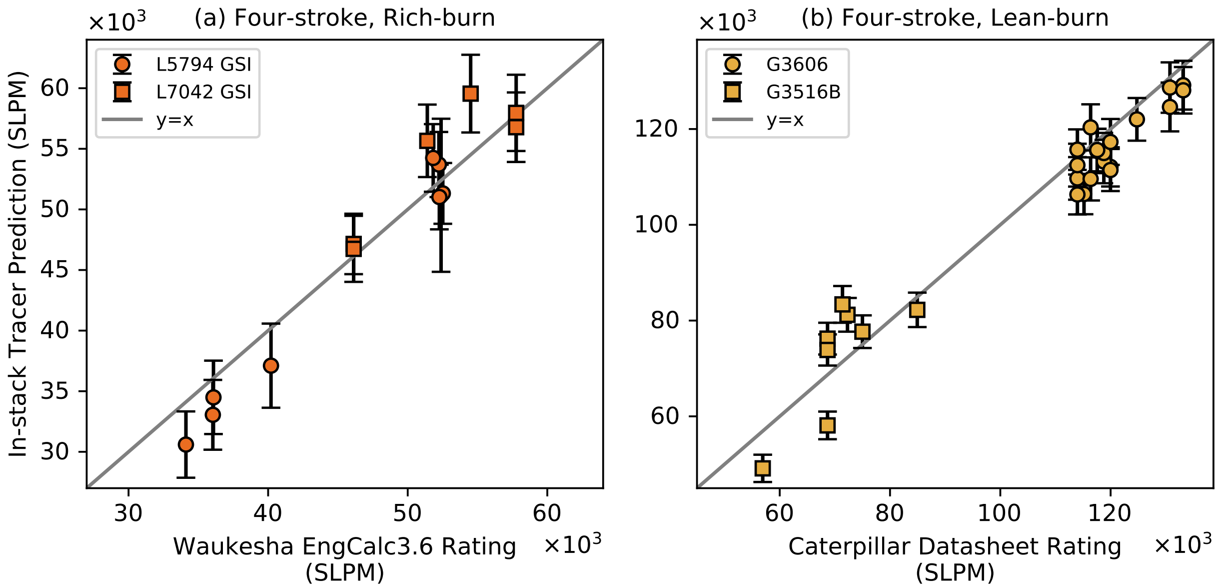


Figure 10: Total stack flows predicted by the in-stack tracer method vs manufacturer specifications for (a) four-stroke, rich-burn units, and (b) four-stroke, lean-burn units. Comparisons were made when manufacturer's software was available and field data supported a comparison. The line of equality (y=x) is shown for reference.

4.2.2 Comparison to EPA Emission Factors

Combustion slip measurements were made on 116 engines (70 4SLB and 46 4SRB) during the field campaign. An example of time series emission and activity data collected for each tested unit can be found in SI figures S2-4 to S2-6. The data reduction methodology outlined in SI S2-2.2 was applied to each set of stack test data to quantify measurement error and calculate in-stack tracer flow and combustion slip emission rates. The resulting combustion slip emission rates were aggregated according to their AP-42 classification (only 4SLB and 4SRB engines were measured during this study) and compared to the following corresponding methane emission factors:

- US EPA compilation of air pollutant emission factors for reciprocating natural gas engines (AP-42) [1]
- US EPA GHGI estimates [30]

- US EPA GHGRP estimates [31]

Study factors were compared in two ways. First, measured combustion slip emission rates were compared directly, without consideration of the difference in the mix of engines nationally compared to the mix measured in the field campaign. A high level overview is provided in Table 8, and more detail in the attached data tables. For the population of lean burn engines measured, study estimates agree well with AP42 and the similar factors used in the GHGI. For the measured rich burn engines, the study estimates half the emissions as AP42, and since the GHGI uses fleet average emission factors aggregating multiple engine types, both the study and AP42 estimate less substantially lower emissions than the GHGI. As noted elsewhere, the GHGRP Subpart C emission factor for engines is not representative of engine emissions, and underestimates by a factor of approximately 500 for lean burns and 45 for rich burn engines.

Table 8: Mean Combustion Slip Emission Factors for Compressor Drivers Measured in the Field Campaign

Engine Type	Number of Engines*	Average Rated HP	Mean Emissions Per Engine ($g \cdot (HP \cdot h)^{-1}$ CH_4) Study	AP42+	GHGI#	GHGRP Subpart C†
4SLB	63	1800	3.10	3.40	3.95	0.0060
4SRB	39	1360	0.30	0.69	3.75	0.0066

* Includes all engines in the field campaign that passed quality control checks. Emission factor is based upon *rated* power, in horsepower.
\+ Ref. [1]
\# Ref. [30]
† Ref. [31]

Second, published emission factors were applied to the population of engines measured in this study. The resulting combustion slip emission rate estimates were compared to those measured directly in this study. This approach was used because the combustion slip emission factors used in the GHGI appear to be based on the emission factors from the GRI/EPA 1996 report [32], which include activity weighting applicable to the population of compressor engines in use at the time of publication. The distinction between "measured emission factors" and "activity-weighted" emission factors is important to note when attempting to use these factors to estimate emissions. The underlying mix of equipment, and utilization rates, may change with time, which in turn may decrease the future accuracy (or even applicability) of activity-weighted emission factors. Additionally, while activity weighted emission factors may properly account for emissions in aggregate (national, an entire industry), they may have limited value for gaining insight into emissions at finer scales (regional, sub-sector, facility).

4.3 Pneumatic Controllers

Long-duration measurements were successfully made on 72 PCs (40 intermittent vent, 24 low bleed and 8 high bleed PCs) at 15 natural gas gathering compressor stations between June 2017 and May 2018. The average measurement duration of these recordings was 76 hours. To anonymize each data set, stations visited were assigned a randomly generated letter and each PC measured on that site was given a number 1-6 corresponding to the number of the flow meter that was connected to that device. All measured devices were then identified using this naming scheme. The gas temperature, pressure and flow rates recorded for PC D-1 (measurement made on site 'D' using meter #1) are shown in Figure 11.

Comprehensive metadata were collected for each PC measured at each station. Metadata collected included PC make/model, process variable controlled, operational mode of controlled valve (throttling or snap acting), associated major equipment, and EPA classification. Metadata for device D-1 is shown in Table 9.

Time series plots of emissions rates and metadata for all PCs measured during this study are included in SI S1-7. The proportional band settings (for PCs fitted with this feature) and the supply gas pressures when meters were attached to vent ports *were not* recorded in the field. A PC's proportional band and supply gas pressure can have a significant effect on the expected emission rate and should be recorded in future studies.

During the final deployment of the field campaign, it was discovered that the flow meters used

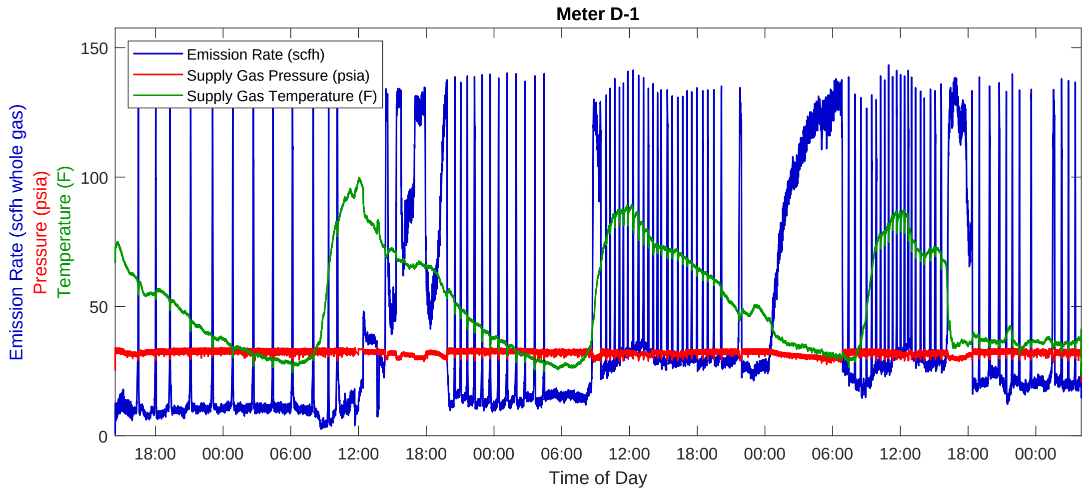


Figure 11: Example of flow meter recordings of PC emissions, supply gas temperature and supply gas pressure for Site D, meter 1, recorded over an 85-hour period. D-1 is an intermittent vent PC that exhibits multiple abnormal behaviors. For a substantial fraction of the recording period, emissions do not return to zero between actuations – one type of abnormal behavior. In addition, while D-1 actuates quickly during some recorded periods, it shows no distinct actuations and elevated emissions during other periods. As a result, D-1's emissions are significantly higher than emissions from D-4, shown in Fig. 12 as an example of a properly functioning intermittent vent controller.

Table 9: Summary of metadata relevant to device operation collected for PC D-1

PC Specific Data	Valve Operation[1]	EPA Type[2]	Major Equipment[3]	Process Variable	PC Make Model
PC D-1	Snap Acting	IV	Compressor	Liquid Level	Murphy L1200N

[1] 'Snap acting' or 'throttling' designation provided by station operator.
[2] Intermittent vent, low bleed or high bleed designation originally provided by station operator. Inconsistencies in EPA type identification were clarified and resolved by independent panel (Section S1-5)
[3] Major equipment category where PC is operating. Compressor, dehydrator, separator, yard piping or acid gas removal unit.

in the study recorded non-zero (referred to as NZ) flow rate values when the meter was pressurized, but gas was not flowing. Lab tests showed that readings increased with higher supply gas pressure and decreased to near-zero at supply gas pressures below 30-35 psia. Flow meters installed in-line on PCs with supply gas pressures above 30-35 psia consistently exhibited NZ behavior.

Laboratory testing performed after the field campaign at METEC quantified the NZ error [SI

S1-4.2.1], establish meter specific pressure-NZ value correlations [SI S1-6], develop a data correction method based on these correlations [SI Table S1-1], and test the efficacy of the correction method under field conditions [SI S1-4.5]. A complete summary of corrections applied to each data set is outlined in SI S1-4.3. The results of these tests indicated that 42% of measured PCs were impacted by NZ error, to varying degrees. Data from 14 PCs (of 86 PCs sampled in total) were discarded after corrections were applied, as it appeared all gas flow recorded for those tests could be due to meter error [SI S1-7.4]. The severity of the impact on the remaining 72 successful measurements are summarized and discussed in SI S1-4.4. The data summaries provided [SI S1-7] are organized by severity of the NZ error on measurements.

The most significant implication of this meter error is the effective increase of the meter's lower detection limit at higher supply gas pressures. At pressures where a meter can show a false NZ reading, any actual flows below the NZ baseline are indistinguishable from meter noise. After correcting for this problem, there are restrictions on the use of the resulting data.

First, while the corrections have an impact on the average emission rates, they do not obscure the qualitative emissions behavior of the PC. Corrections only impact (i.e. obfuscate or even zero out) measured emission rates near the low end of the meter range. Measurements of higher emission rates, which define the overall behavior of the PC, are not impacted by this correction. Therefore, the measurements affected by NZ behavior can still be used for qualitative evaluation of PC emission behavior.

Second, the meter error and corrections have a non-uniform impact across the population of PC types. In particular, a subset of the population was discarded, which may impact certain types of emission behaviors disproportionately, and bias the remaining sample. Therefore, average emissions rates (i.e. emission factors) are impacted in an unknown, possibly biased, fashion and *should not* be used for quantitative purposes, such as developing new emission factors for PCs in service at gathering stations.

The long-duration measurements recorded during this study provide insight into PC emissions behaviors that are not reflected in manufacturer's literature and have not been shown in prior studies. Analysis of recorded PC data shows a high degree of variability in operation over the course of hours or days, especially for intermittent vent PCs. PC data also show frequent occurrences of irregular emission behavior, inconsistent with intended operations.

To understand the qualitative behavior of the PCs, the study team assembled a panel of four industry experts to evaluate time series data from each PC. The panel first confirmed the EPA classification for each PC based on its make, model and service application. The panel and study team then categorized each PC's emission behavior as normal or abnormal. [SI S1-5] The panel developed rules to classify each PC as normally or abnormally operating:

High-bleed PCs were deemed to be operating normally if emissions were below the maximum specified by the manufacturer [SI S1-5.2]. The average emissions from all eight of the high-bleed PCs measured in this study were consistent with manufacturer specifications, and therefore operating normally from an emissions perspective.

Low-bleed PCs were deemed to be operating normally if average emission rates were below the EPA threshold of 6 scfh [SI S1-5.2]. Five of 24 low bleed PCs had average emissions that exceeded the 6 scfh threshold [SI Figure S1-24]. The average emission rates for these five abnormally operating PCs were much higher than the emission rates for normally operating PCs (34 [+20.57/-19.78] scfh vs 0.68 [+0.50/-0.42] scfh). These five PCs also had high emission rates throughout the measurement period.

Random sampling of short-duration (15 minute) samples from the multi-day data sets demonstrates that the emissions from both high-bleed and low-bleed PCs were generally consistent over the duration of recordings [SI Figure S1-23].

Intermittent-bleed PC's showed a wide range of emission patterns and required a more comprehensive set of criteria to categorize emission behavior. An example of emissions from a normally operating intermittent-bleed PC are shown in Figure 12.

For the population of intermittent-bleed PCs measured in this study, 15 exhibited this expected

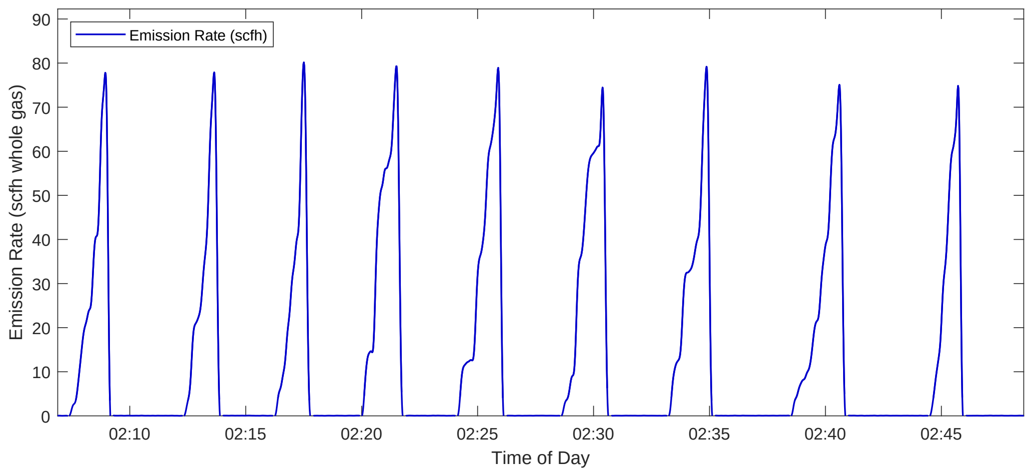


Figure 12: Time series emission data for a normally operating intermittent-bleed PC. This behavior is characteristic of intended operation; The emission profile shows distinct actuation events (ie. short peaks in emissions) that are < 3 minutes in duration, and emissions return to zero between each actuation event. 15 of 40 intermittent-bleed PCs measured in this study exhibited this expected emissions profile

emissions behavior. The remaining 25 PCs showed unexpected emission patterns at some point during measurement. The industry panel evaluated the time series emission data for each of these 25 PCs and established four categories to classify abnormal emission patterns [SI S1-5.2]:

1. Continuous emission rates or lack of distinct actuation events [SI Figure S1-18]
2. An extended ramp up in emissions prior to actuation events [SI Figure S1-19]
3. Emissions not returning to zero between actuation events [SI Figure S1-20]
4. Other irregular behavior [SI Figure S1-21]

Approximately 50% of the intermittent-vent PCs that had abnormal emissions violated more than one of the above criteria for abnormal operation. The criteria violated by each abnormally operating PC is shown in SI Table S1-22.

The time each intermittent vent PC exhibited abnormal emission behavior was variable. By assuming several parameters to define *normal* behavior, it is possible to calculate the amount of time each PC exhibited abnormal emissions using the criteria established by the expert panel. The algorithm uses signal processing to locate emission peaks in time series data [SI S1-2] and then makes the simple assumption that a "normal actuation" should last 3 minutes before, and 5 seconds after the peak. Any emissions within this time window are normal; any outside are attributed to abnormal behavior.

As an example, Figure 13 shows one recording shaded to highlight emissions occurring during abnormal operation. In this example, the majority of emissions are due to abnormal operation.

While new emission factors cannot be developed from the long-duration PC emission measurements, the data provide insight on the frequency of abnormal PC behavior, and its affect on emissions. The relatively high occurrence of abnormal behavior – 25 of 40 intermittent vent PCs – indicate that more information is needed.

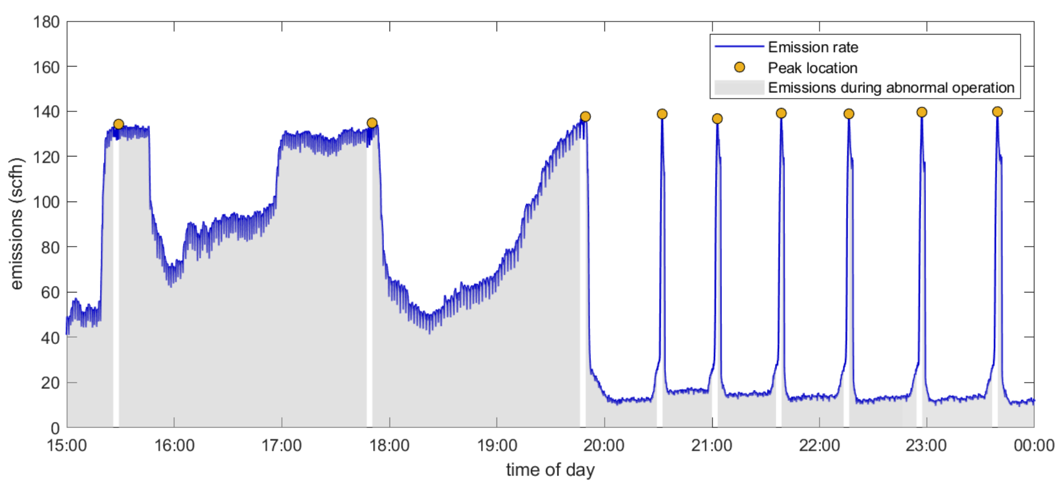


Figure 13: Time series of pneumatic controller emissions that exhibits multiple criteria for abnormal operation. The gray shaded area indicates times when the PC is emitting abnormally, based upon criteria established by an expert panel. Yellow circles indicate where control actuations were detected. Emissions for three minutes prior, and 15 seconds after, the yellow circle are considered normally-operating emissions. Over the first 7.5 hours of this recording the pneumatic controller emits gas continuously. At 19:50, the pneumatic controller begins showing distinct actuation patterns, but the actuation events last 8-10 minutes and emissions do not return to zero between events.

4.4 Station Emissions

Station emissions estimates include estimates for all non-episodic methane emissions at a station, including fugitive and vented emissions, combustion slip, and flaring. Episodic emissions – primarily unit and station blowdowns – are not included to make the results comparable to previous studies which did not measure episodic events [3].

The field campaign measured emissions on 180 gathering stations, which represented 11% of all partner stations. Of the 180 stations, 177 stations had one or more units of major equipment screened and measured. The remaining 3 stations had no complete units of equipment screened and measured, either due to time constraints or weather conditions. All stations had at least one compressor, 54% had dehydrators, and 93% had atmospheric tanks. Stations ranged from small stations consisting of a single compressor skid with an electric motor drive to large facilities with more than 10 compressors.

Emissions for each station were computed by summing all of the emissions for the station. If a unit of major equipment was screened and measured, those emissions were used; if not, emissions were drawn from the major equipment emission factors developed in this study. Emissions from dehydrator and AGRU vents, flares, and pneumatic controllers were estimated using GHGRP methods and emission factors. Combustion slip was estimated as described elsewhere in this report. SI S3-5 discusses the modeling of each emission source in more detail.

Station emission estimates are provided in Table S3-44 in SI S3-5.1. Each station was classified by the type of equipment on the facility:

- *C:* Compression only
- *C/D:* Compression and dehydration
- *C/D/T:* Compression, dehydration and treating, i.e. acid gas removal.
- *C/T:* Compression and treating

The number of compressors at each station is also listed. While compressors vary widely in gas throughput, the number of compressors is a reasonable surrogate for station size. The table also lists the number of large emitters, electric compressors, and whether the station used instrument air for pneumatic controllers. For the 157 stations where throughput was available, throughput-normalized emissions are also provided in the table.

Station emissions span five orders of magnitude, from 0.00386 to 437 $kg \cdot h^{-1}$ CH_4. Throughput spans a similar range, from 0.03 to 260 MMscfd whole gas. While throughput and emissions are also correlated ($R^2 = 0.63$), the range of throughput-normalized emissions is similarly broad, at 0.0052% to 12% of throughput.

Figure 14 illustrates station emissions and correlation between throughput and emissions. While throughput and emissions are correlated, two groups of stations have different emission characteristics than the rest of the stations. First, the field campaign included 11 stations with only electric compressor drivers. These stations are also small - all have throughput in the bottom 14% of throughput. It is therefore impossible to separate the emissions impact of electrification from size. Second, 5 stations had throughput below 0.2 MMscfd, and also exhibited emissions lower than the trend line through all other stations. Both the electric and low throughput stations are of an atypical configuration, consisting of only one compressor skid and little other supporting equipment. While no definitive statements can be made, this type of small station appears to have throughput-normalized emissions that are lower than expected for their size and configuration.

Large emitters are scattered across a wide range of throughput and emission rates, exhibiting no clear trend. However, two of the top three emitting stations have two large emitters each, illustrating the impact of large emitters on station emission rates.

Visually, stations with instrument air appear to have emissions below the trend line, and thus lower than other stations, but the effect is not statistically significant. While instrument air indisputably lowers station emissions, the largest fraction of station emissions is combustion slip, which has substantial station-to-station variability, followed by the larger fugitive and vented emitters, which are scattered between stations and therefore also highly variable. The variability in these factors dominates the overall variance in station emissions, and is large enough that the impact of instrument air is not independently visible.

Across all stations, 38% [30% to 43%] of all emissions are due to combustion slip – the largest category of methane emissions. Since combustion slip is strongly related to operating engine horsepower, and throughput is also a function of operating engine horsepower, combustion slip is the principal driver of the correlation between throughput and emissions. Fugitive and vented emissions account for a similar emission rate, 24% [15% to 38%] from yard piping, 21% [16% to 28%] from other major equipment, and 11% [8.5% to 12%] from pneumatic controllers. The remaining emissions are due to flares and AGRU and dehydrator vents.

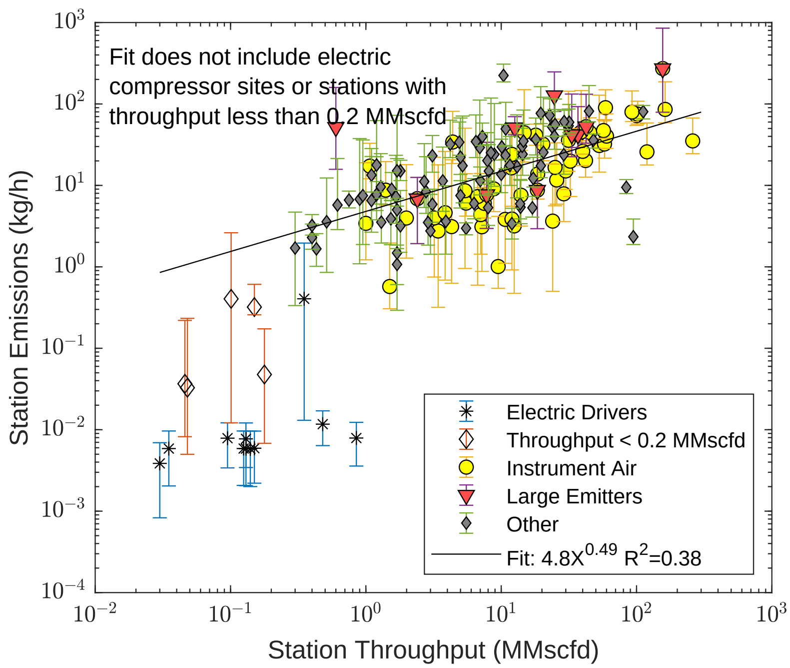


Figure 14: Emission rate as a function of throughput for the 157 stations in the field campaign where throughput data was available. Key characteristics of each station are indicated by point shape, including stations with all electric compressor drivers, stations where gas pneumatics and associated actuators are powered by instrument air, and stations with large emitters. Fit does not include 5 stations with throughput below 0.2 MMscfd or 11 small, all-electric, stations.

4.5 National Emissions

The national emissions model includes all emissions estimated for stations plus estimates for episodic emissions reported to the GHGRP. A primary focus of the national model was to test methods which could be readily replicated for inventories like the GHGI. Like station emissions, the estimate of U.S. national emissions utilizes major equipment emission factors for most emission estimates, coupled with GHGRP estimates for emissions from blowdowns, flares, dehydrator vents and AGRU vents. For activity data, the national model utilizes similar methods to the station estimate, but a largely independent source for the activity estimate: Station estimates used equipment counted during the field campaign, while the national model utilizes equipment counts reported to the GHGRP. The national estimate of emissions is computed by multiplying counts of major equipment units from the GHGRP by major equipment emission factors, and then scaling that estimate to account for units which are not reported to the GHGRP. [SI S3-6.]

GHGRP reports contain neither a station count nor a complete count of separators. To estimate these counts, scaling factors of stations per compressor and separators per compressor were developed from partner data. [SI S3-6.1] These scaling factors were developed *per-basin* to reflect differences in station size and configuration between basins; differences in produced gas composition and the age of the gathering infrastructure are reflected in the station size and design in a basin. Using the developed ratios, we estimate 2.8 [2.68 to 2.93] compressors per station on an average national basis.

While GHGRP reports contain compressor counts, they do not indicate the type of compressor driver, which had to be estimated from partner data to estimate combustion slip emissions.

Finally, GHGRP reports are required only when an operator's total GHG emissions exceed 25,000 mtCO2eq annually. To account for major equipment units that are not reported to the GHGRP, the study scales reports using data about gas production in each basin. Overall, we estimate that 7.5% [6.6% to 8.6%] of stations nationally are not reported to the GHGRP. [SI S3-6.2]

The method described here and in the supplementary volume is suitable for annually updating national emissions from the gathering and boosting sector using annually-reported GHGRP activity data, and any emissions estimates or measurements also reported to the GHGRP.

Table 10 summarizes results from the national model. The study estimates national methane emissions of 1,292 [1,243 to 1,371] $Gg \cdot y^{-1}$, which is statistically lower than the current GHGI estimate of 1,955 $Gg \cdot y^{-1}$. In contrast, we estimate more stations nationally (6,111 [+4.4%/-4.2%]) than the current GHGI estimate of 5,241 stations. Both estimates reflect a larger number of smaller stations in this estimate, compared with previous work completed by Marchese et al.[4] using data from a 2013-14 field campaign [3]. Comparison of the two data sets indicates that the previous work sampled more complex stations – a higher fraction of stations with both compression and dehydration – that generally operated at higher throughput than this study. This differences may explain a substantial portion of the emissions difference, as discussed for station emissions in Section 4.4. Two factors lend credibility that this study may be a more representative, and more current, sample of gathering stations nationally: First, this study drew its sample from a larger partner station population (1705 stations versus ≈700 stations) provided by a more diverse set of operators (9 operators versus 4 operators). Second, activity data from the GHGRP, which was not available to the previous study, provides activity data from a large set operators for the entire U.S.

Additionally, in the intervening four years since the Mitchell measurements [3], methane emissions have received substantial attention in *all* natural gas sectors [33, 34]. As a result, there is anecdotal evidence that operators have placed additional emphasis on reducing emissions during operations and have emphasized lower emission designs when developing new stations.

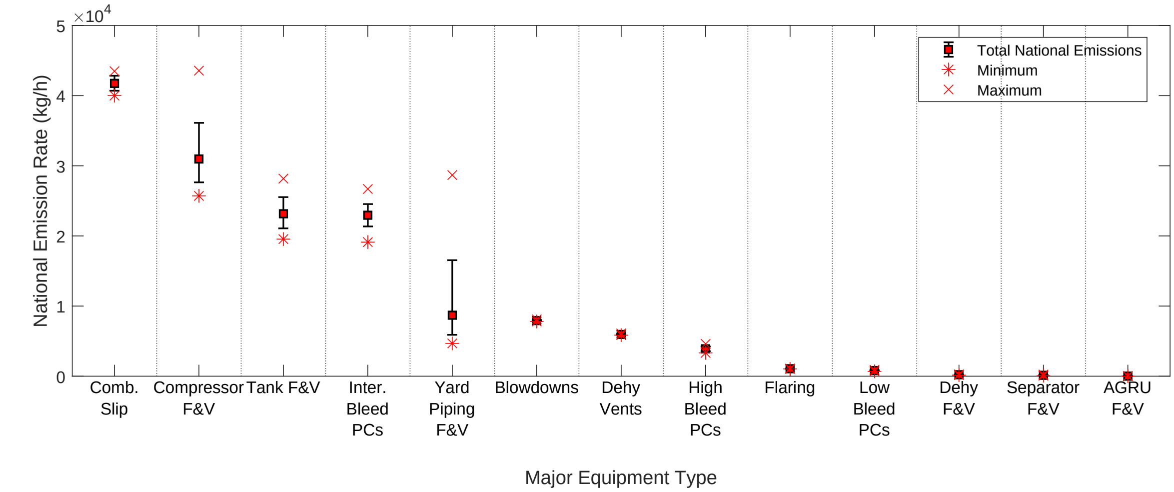
Figure 15 illustrates the contributing categories for the national emission estimate. As with station emissions, combustion slip is the largest component of methane emissions for the sector, accounting for over 40% of emissions. Fugitive and vented emissions from compressors and tanks, as well as intermittent bleed pneumatic controllers, are also significant contributors. Nationally, approximately 71% of pneumatic controllers are intermittent bleed devices, and 24% are low continuous bleed devices.

Table 10: National and Station Summary of Emissions

Estimate	Total Methane Emissions ($Gg \cdot y^{-1} CH_4$)	Activity Factor (Stations)	Emission Factor ($kg \cdot h^{-1} station^{-1} CH_4$)
National Estimate & Comparison			
Marchese et. al [4]	1697 [1,512 to 1,886]	4,459 [3,756 to 5,380]	42.6 [34.6 to 52.6]
EPA GHGI[9]	1,955.1	5,241	42.6*
This Study	1,292 [1,243 to 1,371]	6,111 [5,852 to 6,377]	24.2 [22.8 to 25.9]
Study Field Campaign Comparison+			
Mitchell et. al [3]		115	55.5 [41 to 73]
Study Field Campaign		180	24.2 [18.5 to 31.2]

* Current GHGI estimate for G&B uses the Marchese et al. emission factor.
+ Comparison of field campaign results does not include episodic emissions, which were not measured in either field campaign.

(a) Emission Rate



(b) Fraction of total emissions

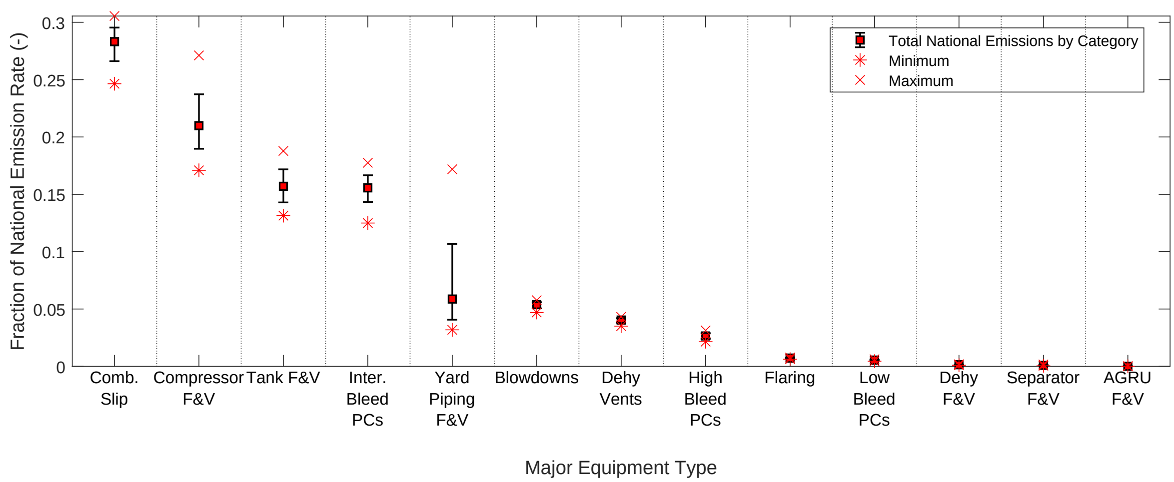


Figure 15: Estimated national emissions divided into categories by major equipment and emissions type. Top panel provides the emission rate for each category. Bottom panel indicates the fraction of total emissions in each category. Fugitive and vented emissions, including emissions from leaks and normally operating vents, are indicated as "F&V". Combustion slip accounts for methane in combustion exhaust from compressor drivers, dehydrator vents for methane in dehydrator reboiler vents, and flaring for methane in flare combustion exhaust. Blowdowns include system and unit blowdown events; leak emissions through closed blowdown valves are included in the F&V emissions for the equipment units where the blowdown vents were located. Dehydrator vents, blowdowns, and flaring emissions were taken directly from GHGRP reports and not measured in the field campaign.

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