FINAL PROJECT REPORT

US DOE NETL Award Number DE-FE0031702

Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells

Issued: 28 April 2022

Prepared for: **U.S. Department of Energy**
National Energy Technology Laboratory

GSI Environmental Inc.
9600 Great Hills Trail, Suite 350E ■ **Austin, TX 78759** ■ **P:** 512.346.4474 ■ www.gsienv.com

TABLE OF CONTENTS

TABLES

FIGURES

APPENDICES

Abbreviations and Acronyms

BHFS .... Bacharach hi-flow sampler
BOE .... Barrels of oil-equivalent
CSU .... Colorado State University
DOE .... Department of Energy
EIA .... Energy Information Administration
EPA .... Environmental Protection Agency
GHGRP .... Greenhouse Gas Reporting Program
GSI .... GSI Environmental Inc.
IOGCC .... Interstate Oil & Gas Compact Commission
LDAR .... Leak detection and repair
METEC .... Methane Emissions Technology Evaluation Center
MBOE .... Thousand barrels of oil-equivalent
MCFD .... Thousand cubic feet of gas per day
NEPA .... National Environmental Policy Act
NETL .... National Energy Technology Laboratory
NSPS .... New Source Performance Standards
OGI .... Optical gas imaging
OTM .... Other Test Method
QA/QC .... Quality assurance/quality control
scfh .... Standard cubic feet per hour
TASC .... Technical Advisory Steering Committee
TPY .... Tons per year

1.0 EXECUTIVE SUMMARY

1.1 Background

There are over 990,000 oil and natural gas wells in the U.S., of which approximately 783,000 (79 percent) are considered "marginal" in terms of their profitability to operators, or low production, defined as producing less than 15 barrels of oil equivalent (BOE) per day of combined oil and natural gas. Marginal wells are a significant source of energy for the U.S., currently accounting for 7 to 8 percent of total oil and gas production (EIA, 2020). In 2018 and 2019, the five states with the largest reported numbers of marginal gas wells were Texas, Pennsylvania, West Virginia, New Mexico, and Oklahoma, and the five states with the most reported marginal oil wells were Texas, Kansas, California, Oklahoma, and Louisiana (EIA, 2020).

In recent years, stakeholders have expressed disparate views regarding whether marginal well sites should be subject to or exempt from fugitive emissions monitoring and associated details of the U.S. Environmental Protection Agency's *New Source Performance Standards* (NSPS, 40 CFR Part 60, Subpart OOOOa), which regulate fugitive emissions from new and modified oil and natural gas facilities. Many independent oil and gas producers contend that potentially expensive leak detection and repair (LDAR) requirements could affect all producers but will, in particular, affect small oil and gas operators of marginal wells, with an associated economic impact. Environmental interests have reasoned that frequent monitoring of emissions from marginal production is necessary for the U.S. to achieve critical methane emission reductions. Despite points of disagreement, stakeholders have generally agreed there is a critical need for a substantial body of nationally representative data on marginal well emissions and associated activity factors to support future decisions and rulemaking on this important issue.

1.2 Study Objective and Approach

This project commenced in March 2019 under an Assistance Agreement with the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), with supplemental cost share provided by oil and gas industry partners. The objective of this research was to measure methane emissions from marginal well sites at various basins across the United States. The goal was to collect and evaluate representative, defensible, and repeatable data and draw quantifiable conclusions on the extent of emissions from marginal wells across oil and gas producing regions of the U.S., and to compare these results to published data on the emissions from nonmarginal wells. A Technical Advisory Steering Committee that included stakeholder representation from industry, federal and state regulatory agencies, non-government organizations, and academia was engaged to provide input and feedback on key project activities. The scope of work primarily consisted of the major tasks summarized below, each described further in the main body of this report.

1.3 Regional Field Campaigns

Employed Procedures: Field site selection and all field activities were performed in accordance with procedures detailed in Regional Field Workplans (GSI, 2019b, 2020). Facilities were selected for measurement using geographically clustered, random sampling. All gas emissions were detected using an optical gas imaging camera and quantified, where possible, using a Bacharach Hi-Flow sampler in conjunction with gas composition-specific analyses or downwind measurement methods.

Visited Field Sites: Overall, 589 oil and gas production sites were visited in coordination with 15 participating host operators, who in addition to direct access to perform emission screening and measurements, provided valuable activity data. Among visited sites, 524 exhibited marginal production at an average rate of 2.5 BOE per day of combined oil and natural gas. Sitewide production or throughput was nonmarginal at 65 sites (approximately 11% of the total visited), where production ranged from 15 to 2100 BOE per day. The relatively small size, low equipment counts, and ease of accessibility of most emission sources led to complete screening at all visited sites and complete measurements of most observed emissions. Besides emissions screening and measurements, detailed activity data, including major equipment counts and oil and gas production rates, were documented at each visited site.

Frequency and Magnitude of Detected Emissions: On a sitewide basis, no emissions were detected at approximately 55% of visited natural gas production sites and approximately 60% of visited oil production sites. Overall, emission rate measurements across the entire study exhibit the long-tail behavior commonly observed in air emissions studies. Figure E1 provides additional perspectives on the relative extent and magnitude of methane emissions among key subpopulations of sites. These plots compare distributions of estimated sitewide methane emissions among site populations distinguished by main product (natural gas vs. oil) and region. Approximately 90% of the observed methane emissions were less than 16 standard cubic feet per hour (scfh; 0.25 kg/h or 2.4 tons per year [TPY]), and 95% of the observed emissions were less than 38 scfh (0.60 kg/h, 5.8 TPY). Study wide, the top 10% of emitting sources contributed 90% of the total methane emissions observed. The ten largest observed sources, each emitting between 100 and 780 scfh of methane (1.6-12 kg/h, 15-120 TPY), accounted for 2% of the total measured emissions.

Equipment-Specific Emissions: Separators, wellheads, and tanks were by far the most common equipment encountered for all types of sites and exhibited the largest volumes of emissions. Section 5.3 of this report summarizes the types and numbers of all major equipment encountered at the visited sites, the frequency and magnitude of detected and measured emissions, and applicable emission factors for emitting equipment and full populations of observed equipment consistent with emission factors used in the EPA's Greenhouse Gas Reporting Program (GHGRP).

1.4 Data Analyses

Exploratory Data Analyses: Statistical exploratory data analyses were performed on the results of the regional field campaigns to identify and assess the significance and strength of correlations among key site metadata and the frequency and magnitude of detected whole gas and methane emissions. These analyses indicate that sitewide methane emissions from oil and gas well sites are most strongly correlated with main product type, major equipment counts, and total oil and gas production rate. No other factors, including geologic basin, geologic region, size, age, well type, etc. were found to be as or more strongly associated with frequency and magnitude of sitewide methane emissions.

Among visited field sites, both the frequency of detected emissions and magnitude of methane and whole gas emission rates are most strongly correlated with the sitewide count of major equipment and weakly correlated with site total oil and gas production rate. The frequency of separator emissions is strongly associated with the number of phases of the separator (two or three) in addition to site production rate. Only weak associations were found between emission detection frequency and evaluated characteristics of tanks and wellheads.

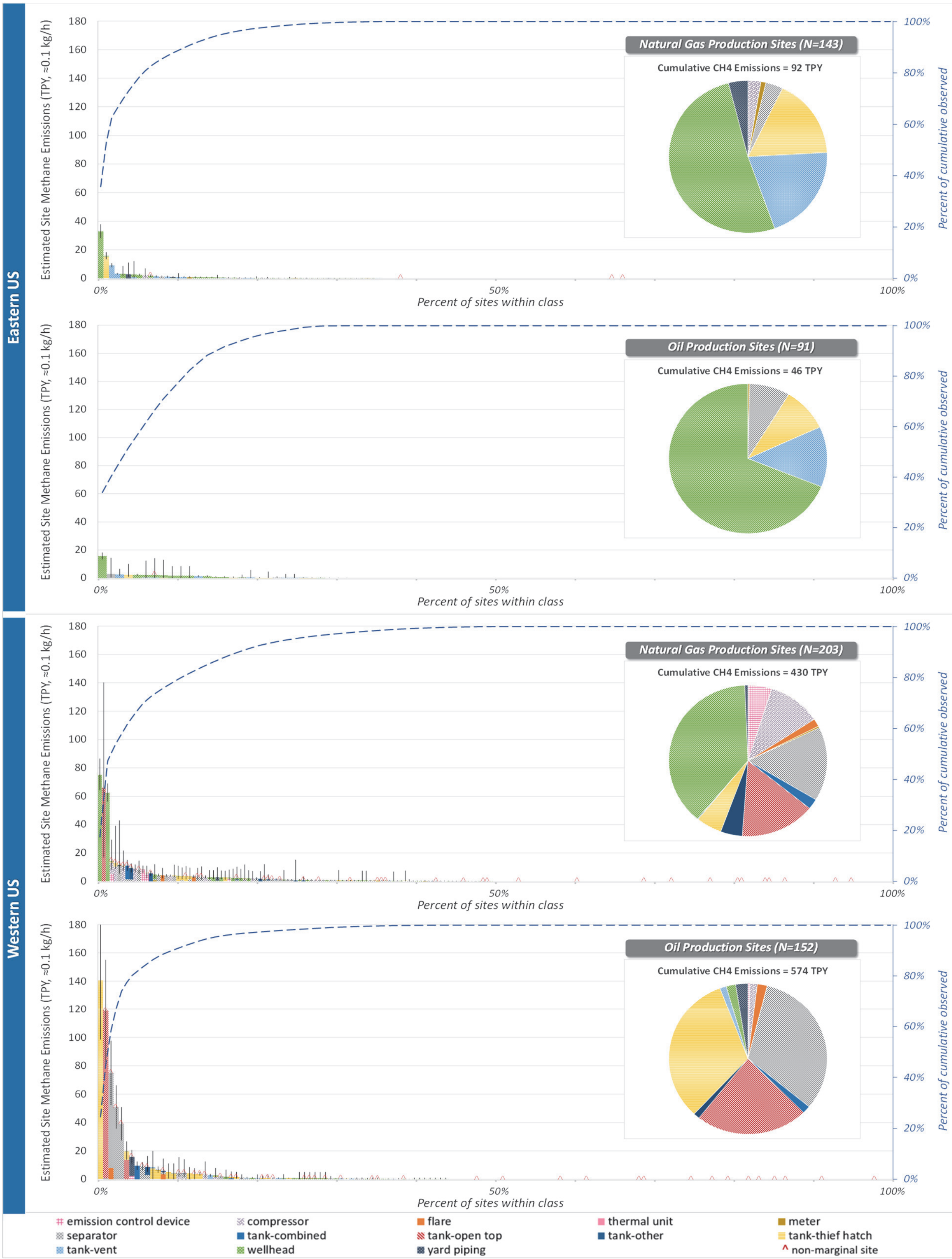


***Figure E1**. Distribution of observed sitewide and equipment-specific methane emissions among visited site subpopulations.*

Production Site Category Emission Profiles: Based on the relative frequency and magnitude of methane emissions observed across all sites visited in the regional field campaigns, applicable emission factors were developed for each of 22 site categories defined and parameterized based on three key distinguishing factors: predominant production type (oil or gas), total oil and gas production rate, and site “size” defined in terms of the total count of major equipment. The upper chart in Figure E2 summarizes the number of visited field sites in each category together with related values on the frequency of detected and measured emissions. The lower chart in Figure E2 summarizes values of two alternate forms of applicable population average emission factors for each site category, one based on absolute emissions per site (left side axis, units of TPY/site) and the other normalized per the total corresponding site oil and gas production (right side axis, units of ton/MBOE).

It is important to recognize that the results of this study correspond only to emissions observed at the time of each site visit and do not include episodic high emission events, such as liquids unloading or manual liquids removal, which were not a key focus of this study and were not observed during the visit to any site. Study-wide, host operators reported that liquids unloading events occurred with varying frequency at 118 of the visited sites.

Relative Magnitude and Extent of Production-Related Methane Emissions: For comparative purposes, state-specific and nationwide estimates of total methane emissions from marginal vs. nonmarginal oil and gas production were developed based on published statewide well counts and production data in combination with key results of this study, including operator-provided activity data from the initial desktop study, the frequency of emissions from key sources, and the magnitude of such emissions based on collected measurements. These estimates account for a wide range and diversity of field conditions, site characteristics, production and equipment types, operational processes, and both permitted and fugitive emission sources observed and documented “as is, where is” at the marginal and nonmarginal production sites visited in the regional field campaigns.

Using both types of average population emission factors shown on Figure E2 for each of 22 discrete categories of production sites, total annual methane emissions were estimated for each oil and gas producing state in the U.S., based on i) the total number of sites in each category times a site count-based emission factor and ii) the total oil and gas production from sites in each category times a production-based emission factor. Considering the combined effects of the multiple sources of uncertainty, Monte Carlo simulations were performed to derive reasonable central, lower, and upper estimates for each state- and category-specific total emission calculation. The resulting annual emission estimates were then summed to yield total statewide and nationwide estimates for key site populations of interest, including marginal vs. nonmarginal gas wells and marginal vs. nonmarginal oil wells. These results are summarized on Table E1 and in Figure E3.

The results of this study suggest that i) marginal oil and gas production in the United States may account for approximately 1 million (±140,000) tons per year (TPY) of “every day” methane emissions, as were observed in the regional field campaigns, ii) marginal gas production accounts for an estimated 60% (±10%) of emissions from U.S. natural gas production, and iii) marginal oil production accounts for an estimated 40% (±10%) of emissions from U.S. oil production.

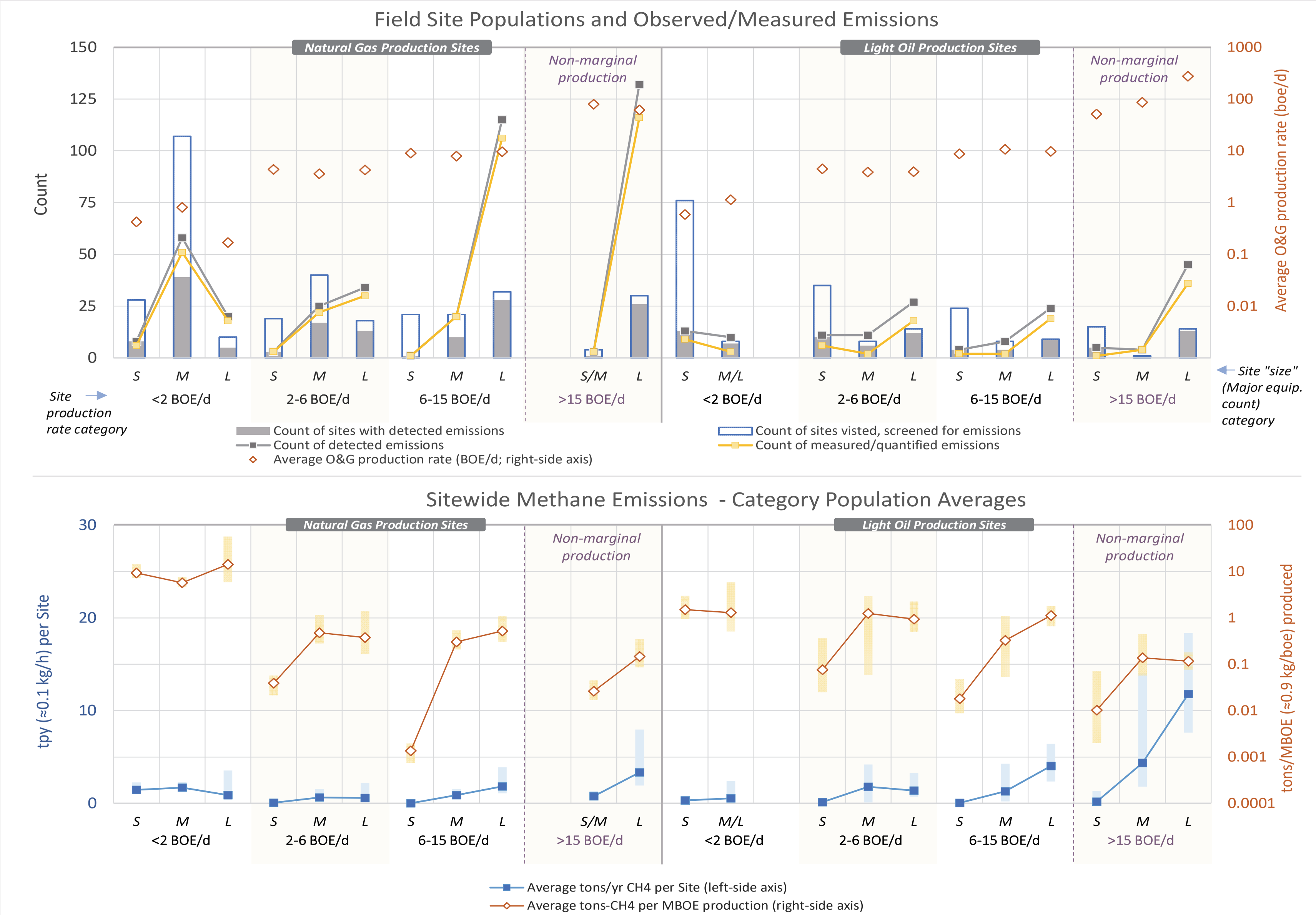


Figure E2. *Production site category population details and average emission profiles*

Table E1. *Relative Estimated Methane Emissions from Marginal and Nonmarginal O&G Production*

	Approx. Well Count		Annual Production		Estimated Cumulative Methane Emissions			Avg. Pop. Emission Factors	
	count	share	boe/yr	share	ton/yr	Tg/yr	share	tons/yr/well	ton/MBOE
Natural Gas Production									
Marginal	420,000	78%	4.6E+8	7%	640,000 ±80,000	0.58 ±0.08	59% ±12%	1.5 ±0.2	1.4 ±0.2
Nonmarginal	120,000	22%	5.8E+9	93%	450,000 ±170,000	0.41 ±0.16	41% ±12%	3.7 ±1.4	0.077 ±0.030
total gas	*540,000*	*100%*	*6.2E+9*	*100%*	*1,090,000 ±260,000*	*0.99 ±0.23*	*100%*	*2.0 ±0.5*	*0.18 ±0.04*
Oil Production									
Marginal	363,000	80%	3.2E+8	8%	360,000 ±50,000	0.33 ±0.05	37% ±9%	1.0 ±0.1	1.1 ±0.2
Nonmarginal	88,000	20%	3.9E+9	92%	610,000 ±150,000	0.55 ±0.14	63% ±9%	7.0 ±1.7	0.16 ±0.04
total oil	*451,000*	*100%*	*4.2E+9*	*100%*	*970,000 ±210,000*	*0.88 ±0.19*	*100%*	*2.2 ±0.5*	*0.23 ±0.05*
Combined Oil & Gas Production									
Marginal	783,000	79%	7.7E+8	7%	1,000,000 ±140,000	0.91 ±0.13	49% ±11%	1.3 ±0.2	1.3 ±0.2
Nonmarginal	208,000	21%	9.6E+9	93%	1,060,000 ±320,000	0.96 ±0.29	51% ±11%	5.1 ±1.6	0.11 ±0.03
total oil & gas	*991,000*	*100%*	*1.0E+10*	*100%*	*2,060,000 ±460,000*	*1.87 ±0.42*	*100%*	*2.1 ±0.5*	*0.20 ±0.04*

Regionally, the Appalachian Basin appears to generate the largest volume of marginal production-related methane emissions from any single geologic basin, with an estimated 290,000 TPY coming from Pennsylvania, West Virginia, and Ohio, New York, Maryland, and Virginia representing 29% of methane emissions from US marginal oil and gas production. Texas, Oklahoma, and New Mexico, which encompass the Permian Basin plus large parts of the Anadarko, San Juan, and other basins, together emit an estimated 380,000 TPY of methane.

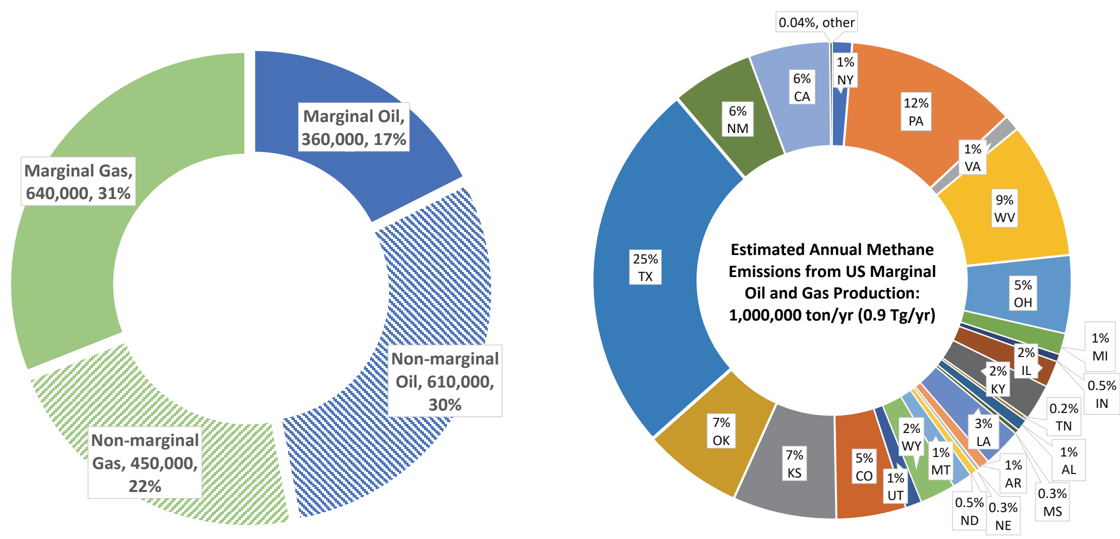


Figure E3. *Relative estimated methane emissions from marginal and nonmarginal O&G production.*

2.0 PROJECT OVERVIEW

2.1 Background

There are over 990,000 oil and natural gas wells in the U.S., of which approximately 783,000 (79 percent) are considered marginal in terms of their profitability to operators, or low production, defined as producing less than 15 barrels of oil equivalent (BOE) per day of combined oil and natural gas. Similarly, wells producing less than 10 BOE per day are commonly referred to as "stripper wells". Marginal wells currently account for 7 to 8 percent of total U.S. oil and gas production (EIA, 2020; IOGCC, 2016).

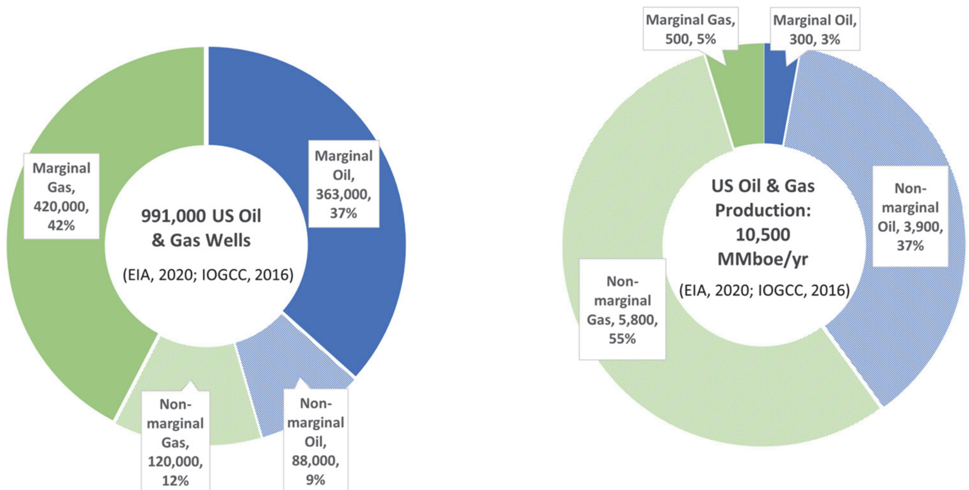


Figure 1. *Current estimated US marginal well population and production.*

In recent years, stakeholders have expressed disparate views regarding whether marginal production operations should be subject to or exempt from fugitive emissions monitoring and associated details of the U.S. Environmental Protection Agency's New Source Performance Standards (NSPS, 40 CFR Part 60), which regulate fugitive emissions from oil and natural gas facilities. (Subpart OOOOa and proposed Subpart OOOOb apply to new, modified, or reconstructed sources, and proposed Subpart OOOOc will apply to existing sources.) Industry research has found that expensive LDAR requirements could preclude potentially decades of continued production from many marginal wells, whose limited profitability already depends on the fluctuating oil and gas market (IOGCC, 2016; Bluestein, 2015). Despite their relatively low production volume, limited earlier research suggested that marginal gas production may be responsible for over 50% of all methane emissions from the U.S. natural gas production segment (Omara et al., 2018).

2.1.1 Federal Regulation of Fugitive Emissions from Oil and Natural Gas Production

The EPA first required semiannual leak monitoring at marginal production sites in June 2016, with amendments to the NSPS, Subpart OOOOa, to reduce fugitive methane emissions from new and modified oil and natural gas facilities. In 2017, EPA granted reconsideration on the applicability of the fugitive emissions requirements to low production well sites. In 2020 EPA rescinded fugitive monitoring requirements for marginal well sites and retained semiannual monitoring for nonmarginal wells. The EPA released information on newly proposed methane emissions regulations on November 15, 2021.

2.1.2 State vs. EPA Fugitive Emissions Monitoring Requirements

Regulations in several states appear to incorporate federal NSPS requirements by reference. These include Kansas, Oklahoma, and West Virginia. In April 2018, during NSPS rulemaking, the EPA analyzed and summarized the requirements of various state fugitive emissions programs for well sites. They compared each state program's requirements to proposed revisions to the NSPS for the oil and natural gas sector (EPA, 2018). This analysis revealed many complexities and nuances of the state programs, which made them very difficult to compare qualitatively. While many differences were noted, EPA concluded that the fugitive emissions requirements related to monitoring, repair, and recordkeeping for California, Colorado, Ohio, Pennsylvania, Texas, and Utah were "equivalent" to those of the NSPS amendments proposed at the time. EPA noted it was unable to determine the equivalency of requirements in Montana, New Mexico, North Dakota, and Wyoming.

In response to EPA's findings, analysts with the Environmental Defense Fund performed an independent comparison in addition to a quantitative analysis accounting for (among other factors) differences in the required timing to repair detected leaks to assess the efficacy of state LDAR requirements to meet specified target methane emissions reductions relative to requirements of both the 2016 NSPS and 2018 proposed amendments. Based on their analysis, they concluded that the existing programs in California and Colorado would outperform the 2016 NSPS requirements in achieving methane reductions, and only these states plus Ohio would outperform requirements of the 2018 proposed amendments (McVay and Roberts, 2018).

2.2 Study Objective and Approach

The objective of this research is to measure methane emissions from representative marginal well sites at various basins across the United States. The goal is to collect and evaluate representative, defensible, and repeatable data and draw quantifiable conclusions on the amount of emissions from marginal wells across oil and gas producing regions of the U.S., and to compare these results to published data available on the emissions from nonmarginal wells. The major sections of the scope of work are summarized below.

- ***Data Source Status Assessment and Master Workplan***: At the onset of the project, key data gaps were identified based on a thorough review of published sources and partially addressed by information derived from a survey of oil and gas well operators for representative production site data across the U.S. This information guided development of a master workplan to establish and document necessary site and technology selection criteria and the overall approach for field data collection, evaluation, and reporting.

  Data for over 80,000 marginal wells were collected in the initial operator survey, 17% of which represented oil wells and 83% gas wells. These numbers equal about 4% of the marginal oil wells and 16% of the marginal gas wells in the U.S. reported by EIA (2020) and IOGCC (2016). Survey responses covered most regions of the country where marginal wells are reported, with notable exceptions being California (where over 40,000 marginal oil wells are reported by EIA) and eastern portions of the Gulf Coast Basin (nearly 8,000 wells in Mississippi and Alabama). Also of note, responses for New Mexico only represented wells in the Permian and not the San Juan Basin (Four Corners area), and responses for Arkansas only represented gas production and no oil production. Overall oil and gas production rates from the operator survey averaged, overall, 1.9 bpd of oil and 13.6 MCFD for gas, which compare very favorably to the average production rates of 2.0 bpd and 13.5 MCFD, reported by IOGCC (2016), and estimates of 2.4 bpd and 17.9 MCFD, based on more recent data from EIA (2020). This suggests the survey data are, in general, representative of national trends with respect to production.

- ***Regional Field Campaigns:*** Between October 2019 and June 2021, methane emissions were screened and measured, where detected, at 524 marginal and 65 nonmarginal oil and gas production sites across multiple U.S. regions and geologic basins. The ultimate objective of these campaigns included capturing the variability and diversity of both physical and operational conditions, especially in areas with large numbers or a high density of marginal wells, or where marginal wells account for a substantial percentage of regional production.
- ***Data Processing, Analysis and Reporting***: Exploratory and statistical data analyses of the comprehensive study dataset were performed to identify key groupings of sites in the studied regions and their distinguishing characteristics and emission profiles. Results were applied to establish site populations to extrapolate and compare nationwide and regional/state-specific estimates of total methane emissions from marginal vs. nonmarginal oil and natural gas production sites across the U.S., including regions not visited in the regional field campaigns.

3.0 REGIONAL FIELD CAMPAIGNS

All of the regional field campaigns were conducted between October 2019 and June 2021, including emissions screening and measurements by scientists with GSI and the Colorado State University (CSU) Energy Institute using the METEC mobile laboratory (see https://energy.colostate.edu/metec/). Based on the frequency of marginal well sites reported in the earlier operator survey responses, the field campaigns were designed to prioritize locations with dense populations of marginal well sites.

3.1 Visited Field Sites

Overall, 589 oil and gas production sites were visited in coordination with 15 participating host operators, who in addition to direct access to perform emission screening and measurements, provided valuable activity data. Site visits were performed in the Appalachian, Forest City, and Illinois Basins, collectively referred to as the "Eastern US" in subsequent descriptions, and the Anadarko, Permian, Piceance, and Upper Green River Basins, collectively referred to as the "Western US" in subsequent descriptions. Field site selection and all field activities were performed in accordance with procedures detailed in regional field workplans (GSI, 2019b, 2020). Regulatory compliance was demonstrated through the issuance of all necessary permits and National Environmental Policy Act (NEPA) approval.

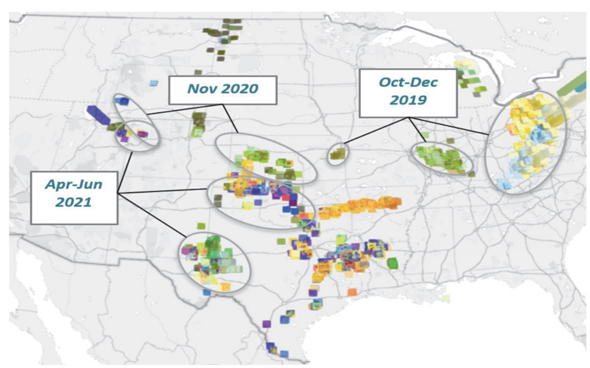


Figure 2. *General locations and times of regional field campaigns.*

Over the course of the field campaigns, a diversity of well design, product separation, and storage configurations encountered contributed to an evolving definition of a "site", with the focus being on collecting data from localized clusters of equipment in close proximity and specifically related to production of a previously identified target wellhead. Thus, a site could include multiple wellheads, while other sites could contain production-related equipment only, such as locations where separation was performed at a central tank battery servicing multiple wells. Such sites were classified as marginal if the total production for all wells sending product to the battery was <15 BOE/d. Figure 3 shows the distributions of total site production rates among visited “natural gas sites” and “oil sites”. The classification of a given site was determined simply by the predominance of either oil or gas production in terms of BOE per day.

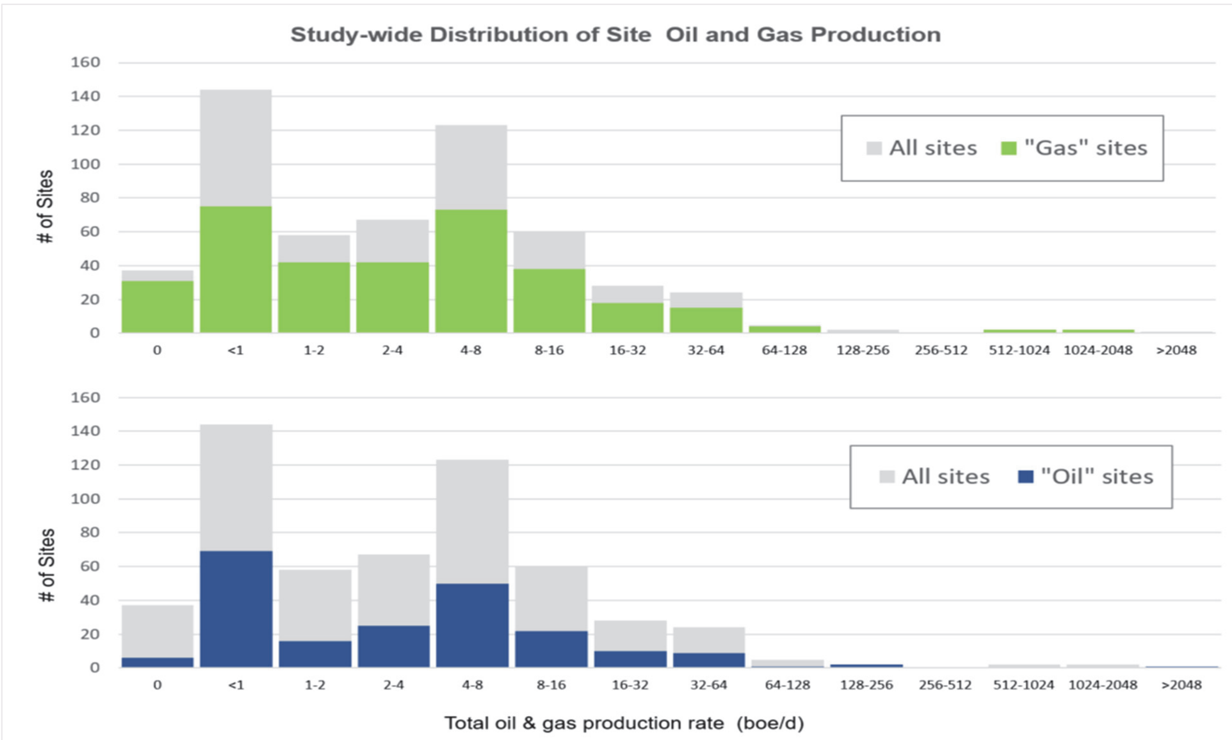


Figure 3. *Study-wide distribution of oil and gas production at visited sites. Sites with total production <15 BOE/d are considered marginal.*

3.2 Field Site Selection

Field sites were selected for measurement using geographically clustered, random sampling. While actual field sites were chosen at random, the initial selection of candidate site clusters was iterative and, to the extent practical, sought to reasonably represent the larger regional and national populations of marginal production sites, maximize the number of facilities visited, and minimize potential biases.

Prior to embarking on each field campaign, target clusters of candidate sites were selected by the research team from region-wide lists provided by each host operator or obtained independently by the research team from a publicly available database. With all operators, candidate site identification was a cooperative and collaborative process largely driven by the research team; therefore, any potential for bias due to so-called volunteer effects is considered low. In the case of large operators, regional candidate site lists included hundreds or, in some cases, many thousands of potentially accessible locations. These were provided by company database managers rather than site managers or environmental personnel. Per agreement with every host, the research team understood all candidate site lists to be fully representative of each operator’s marginal production assets in each target region and, most importantly, that the operator would neither limit nor direct access to potential field site in any way that could bias the results of this study.

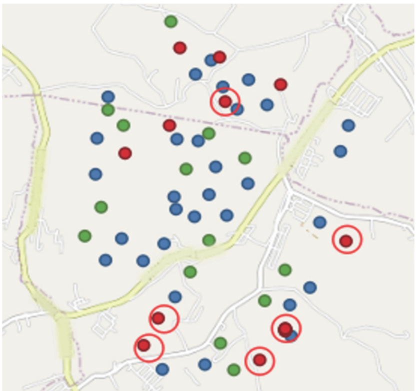


Figure 4. *Daily site selection example. "A", "B", and "C"-sites (red, green, and blue dots, respectively) were chosen at random for measurement. Measured sites are noted with red circles.*

Each day of field sampling was dedicated to a specific cluster of sites with a specific operator. Daily short lists of target field sites were chosen at random by the field team no more than a day in advance of being visited for emissions screening and measurement. This tiered and randomized approach to site selection sought to ensure the integrity of the study results by providing minimal advance notice to operators as to which sites would be visited.

For clusters with more sites than could be visited in a day, the following strategy was used. Sites were randomly selected and rank-ordered as "A", "B", or "C"-sites, which correspond to red, green, and blue dots, respectively, as shown in Figure 4. A-sites were the preferred sites to be visited, then B-sites. C-sites were generally not visited. In rare cases, exceptions were made to this strategy for logistical reasons. For example, if there was time to visit one more site in a day and the next A-site on the list was an hour drive away, a nearby B-site would be visited oppurtunistically to maximize the number of site visits for that day. For clusters with fewer sites, all sites within the cluster were screened.

3.3 Emissions Screening and Measurement

The field investigation team was equipped with a variety of equipment and instrumentation, deployed using various methods, to detect and quantify methane emissions typical of oil and gas operations. Optimal screening and measurement methods were chosen at each site to best capture emissions, considering site-specific circumstances, instrumentation or method limitations, and operator safety. All gas emissions were detected using an Opgal "Eye-C-Gas" 2.0 optical gas imaging (OGI) camera and quantified, where possible, using a Bacharach Hi-Flow Sampler (BHFS) that was specially modified to enable canister samples to be drawn from the inlet flow stream, as shown in Figure 5.

Figure 5. *Emissions identified using OGI and quantified by BHFS.*

Canister samples were drawn for a subset of Hi-Flow measurements and were analyzed for gas species composition by a third-party laboratory. Canister samples were taken for 249 of 460 Hi-Flow measurements to provide insight into typical gas compositions and provide a means for correcting Hi-Flow sensor response variation due to gas composition changes from calibration gas. Multiple samples were not drawn for measurements with a common (or similar) source or if the gas composition did not change at the facility. Instead, the first sample drawn was considered representative. For example, multiple emissions on a common gas feed would rely on the same gas composition sample for correction. Multiple samples were taken when the gas composition was expected to differ significantly. For example, an emission on a wellhead and a tank would require two samples. Further details of the procedure to derive corrected whole gas, methane, and VOC emission rates relative to BHFS instrument readings in the field are discussed in Appendix A.

Additionally, with the METEC mobile laboratory, downwind techniques were available to quantify emissions not suitable for direct measurement with the BHFS, such as due to inaccessibility, high magnitude, or gas composition. Downwind measurements were used to measure large emissions, such as from a tank battery, or where the H_2S content of the field gas presented a safety concern and prevented an attempt at direct measurement. The OTM33a or tracer methods were utilized to quantify 39 emissions which would not have otherwise been measurable due to their size or accessibility. For each of these emissions, only methane was quantified due to the capabilities of the method. Details of the procedures to collect and analyze downwind measurements are discussed in Appendix A.

Among 614 discrete emissions observed at 253 sites, a total of 112 emissions detected at 77 sites were not successfully measured due either to i) malfunctions of the measurement equipment, ii) the emissions not being safely accessible and too small to measure with downwind techniques or, iii) in one case, a host escort closing an open valve before the emission could be measured. All emissions that were identified but not measured are noted and flagged in the field data measurement results. Upon review of the field notes, an additional 13 field measurements with the high flow sampler did not satisfy applicable quality control criteria and were disqualified from use.

Based on OGI recordings of the unquantified emission sources and general observations of the site and equipment operations, these emissions appeared to be “typical” and are expected to fall within the distribution of other observed and measured emissions from comparable emission sources, as characterized in this study. Consequently, for purposes of evaluating statistical population distributions and completeness in estimating values such as total sitewide emissions, detected but unmeasured emissions were accounted for and represented, where needed, by the median emission rate for the corresponding type of equipment in the same U.S. region and, where possible, the same component type. For example, if no qualified measurement is available for an emission observed from a valve on a separator in West Virginia, that emission was represented, as needed, in subsequent analyses by the median of all qualified measurements of valve emissions from separators elsewhere in the Eastern US.

3.4 Site Activity Data Collection

Detailed activity data was documented at each visited site, including oil and gas production rates, major equipment counts, and a general functional description of site processes and activities. Additional data pertinent to understanding any individual measurement, including weather and operating conditions at the time of sampling, and the type and level of fluids in tanks, etc., were also recorded to the extent available.

During each site visit, the host operator representative (usually the site pumper) escorting the sampling team was also “interviewed” to characterize the nature and representativeness of conditions observed during the visit versus at other times, i.e., the expected variability in site conditions with respect to the potential for site emissions. Due to many variations in site layouts, production methods, and equipment types, the host escorts proved invaluable in assisting the field team to recognize and understand many nuances in site conditions and in identifying many different types of equipment, specific components, and relationships among sites, such as product flow from one well pad to a tank on another well pad. Most host operators provided production rate data for each visited site; however, in some cases none was provided or was independently obtained by the research team for a period including up to 1 year prior to the time of the field visit.

4.0 DATA PROCESSING AND ANALYSIS

Upon completion of each field campaign, all collected field notes, photos and recorded OGI video, operator-provided activity data, and emissions measurement data were compiled, archived, checked, and synthesized into a comprehensive project database. Photos and videos from the OGI camera were reviewed to verify the equipment and component type assigned to each emission. All database entries were double checked for accuracy, and all emissions measurements were validated, assessed for usability for further analysis, and either accepted or rejected in accordance with applicable quality assurance/quality control (QA/QC) criteria.

Data analyses were performed on the complete regional field campaign dataset to identify and compare potentially distinct populations of marginal/low producing oil and gas production sites in the studied regions with regard methane emissions and their distinguishing characteristics and emission profiles. For statistical analyses, all data variables were evaluated as either numeric, categorical, or both. For example, in addition to considering exact counts of specific types of equipment as strictly numerical variables, a categorical proxy of site “size” (small, medium, large, etc.) in terms of total major equipment counts facilitated evaluation of a wider range of variable site conditions. Similarly, a series of oil and gas production rate bins was utilized and evaluated as a categorical variable in an effort to reduce the effects of potential unknown inaccuracies or uncertainties in reported production rates. Through the course of exploratory and subsequent data analyses, some of the data were iteratively grouped, divided, and regrouped into relevant categories and subcategories in efforts to identify, characterize, or distinguish significant relationships or findings among the emissions and activity data.

4.1 Exploratory Data Analysis

Statistical exploratory data analyses sought to identify and assess the significance and strength of possible correlations among:

i) Key metadata associated with various characteristics and conditions associated with each visited site, detected and measured emissions, observed equipment, and operational conditions, as documented in the regional field campaigns.
ii) the frequency of detected emissions among visited sites and observed equipment.
iii) the magnitude of qualified methane emissions measurements.

For exploratory purposes, the field site and emissions measurement data and related metadata were sorted, grouped, and evaluated according to two principal subsets: sitewide emissions and equipment specific emissions. Key site factors included the main product type (oil or gas), production rates of oil, gas, and water, frequency of operations, major equipment counts, well or equipment age and condition, region, and operator. A Spearman’s Rank Correlation was used to assess correlations between numeric variables, and a Chi-Squared Test or a Fisher Test (depending on the sample size of the compared dataset) was used to assess the independence of categorical variables. In each case, a p-value of 1% was selected to reject the null hypothesis that any two compared variables are independent. In other words, any test with a p-value less than or equal to 1% indicated the compared variables are not independent and, thus are associated or potentially correlated. For interpretation, the relative strength of association among variables compared using either method was characterized consistently on a scale of 0 to 1 as weak (0.0-0.39), moderate (0.40-0.59), or strong (0.6-1.0) based on the Spearman rank order coefficient (rho) or, for Chi-Squared tests, a normalized primary test statistic. Results of these analyses are discussed in the following section, and additional details on related data evaluation procedures, criteria, and results are presented in Appendix B.

4.1.1 Sitewide Emissions Analysis

Analyses of sitewide emissions separately considered the detection of one or more emissions at any type of equipment, the frequency of emissions expressed as the number of detected emissions divided by the total pieces of equipment at a site, and the total magnitude of methane and whole gas emissions at all sites where 100% of detected emissions were successfully quantified. Importantly, the analysis of site emission detection frequency did not look solely at the absolute emission count (i.e., where one would logically expect the presence of more equipment to correlate with a higher frequency of emissions.) The factors most strongly correlated with sitewide methane emissions are discussed in Section 5.2.1.

4.1.2 Equipment Emissions Analysis

Evaluation of equipment emissions specifically focused on the three most prevalent types of equipment encountered: wellheads, separators, and tanks, which in all of the studied regions were fairly ubiquitous among both oil and gas well sites. These also represent the largest and most frequently observed sources of emissions in all regions. At gas well sites, only meters were encountered with a similar frequency; however, those exhibited relatively few emissions (<3% frequency study wide). Factors considered for wellheads, separators, and tanks included host operator, site production status (active, inactive, shut-in, etc.), basin/region, primary product, oil and gas production rates, and production frequency. Other factors were specific to the equipment characteristics. Tank emissions were evaluated against the quantity of hatches and vents, whether tank vents were atmospheric or pressurized, and the fluid level of the tank while onsite (fullness). Wellhead emissions were evaluated against variables such as the presence of casing vents, well age, well depth (where pressure of the production formation could relate to casing head pressure), artificial lift type, and whether the well was producing brine. Separator emissions were evaluated against variables such as separator age, the number of phases it was designed to separate, maximum design pressure, and operational pressure.

4.2 Emissions-Based Site Category Characterization/Classification

As part of the initial desktop study, a series of site characteristics likely to contribute substantially to overall site-level methane emissions was identified, and related classification criteria were defined to support site selection for the regional field campaigns. These were intended to capture the variability of characteristics encountered among low producing oil and gas well sites throughout the continental US in terms of main product, total oil and gas production rate, and site “size” defined in terms of a total count of major equipment.

As discussed further in the next section, analysis of the results of the regional field campaigns and subsequent data analysis indicate that sitewide methane emissions from oil and gas well sites are indeed most strongly correlated with main product type, major equipment counts, and production rate. No other factors, including geologic basin, geologic region, size, age, well type, etc. were found to be as or more strongly associated with frequency and magnitude of sitewide methane emissions. Based on the relative frequency and magnitude of methane emissions observed across all sites visited in the regional field campaigns, with respect to sitewide emissions the results of this study were evaluated in terms of classification categories defined and parameterized as shown on Table 1.

Table 1. *Production Site Classification Criteria for Methane Emissions Characterization and Estimation*

Parameter	Categories			
Main Product	Natural Gas		Oil	
Production Rate (BOE/day/site)	0-2	>2-6	>6-15	>15 (nonmarginal)
Well Pad Size (Pieces of equipment)	Small (1-2)	Medium (3-5)	Large (6+)	-

All possible combinations of these criteria would give rise to 24 distinct categories. However, across all of sites visited in the regional field campaigns, only one "large" oil site producing <2 BOE/d and no nonmarginal gas sites with fewer than 3 pieces of equipment were visited. For purposes of subsequent data analyses and representation of results, these categories were combined with adjacent categories relative to the size criterion. Figure 6 summarizes the breakdown of field site populations for the resulting 22 site categories and related figures on the frequency of emissions detections and measurements.

4.3 National and Regional Methane Emissions Estimates

For comparative purposes, state-specific and nationwide estimates of total methane emissions from marginal vs. nonmarginal oil and gas production operations were developed based on published statewide well counts and production data in combination with key results of this study, including operator-provided activity data from the initial desktop study, the frequency of emissions from key sources, and the magnitude of such emissions based on collected measurements. These estimates account for a wide range and diversity of field conditions, site characteristics, production and equipment types, operational processes, and both permitted and fugitive emission sources observed and documented "as is, where is" at the marginal and nonmarginal production sites visited in the regional field campaigns.

Based on the geographic extent and range of sites characteristics reported in the operator data survey and judicious design and planning of the regional field campaigns, the sites visited and conditions observed in this study are believed to substantially represent the full range of "every day" conditions and emissions one can expect to encounter in the course of typica LDAR inspections or other fugitive emissions monitoring at most onshore oil and gas production facilities anywhere in the U.S. However, it bears emphasizing that sources of a potentially large fraction of *all* production-related methane emissions, including, in particular, liquids unloading at natural gas wells or other potentially high-emitting episodic events, were neither the focus of this study nor encountered at any visited site. Consequently, use of the word "total" in this report to describe emissions on a sitewide, statewide, or nationwide basis, should be understood to mean "sum" or "aggregate" in the context described above, rather than "all."

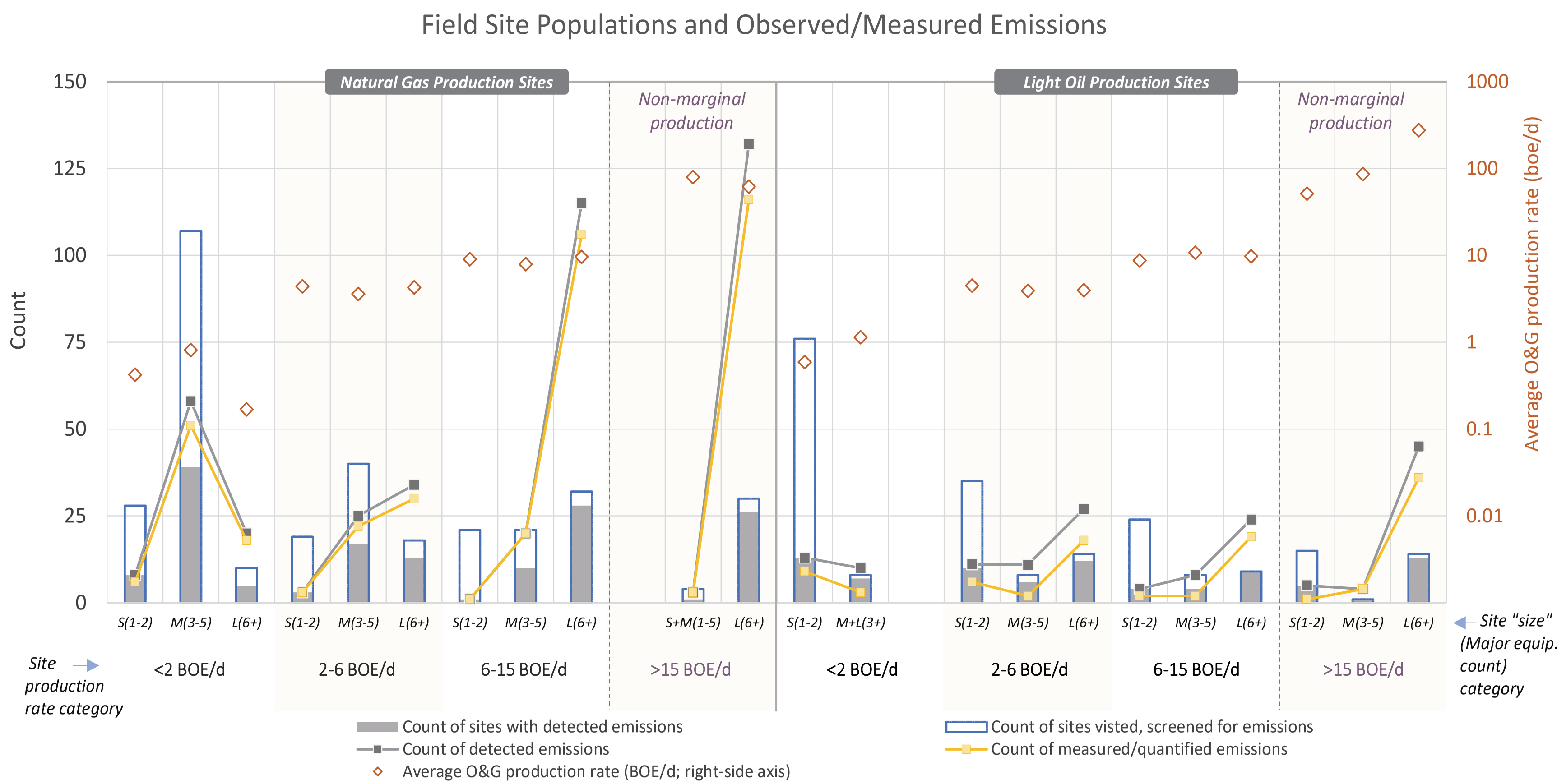


Figure 6. *Field site populations and emission detection/measurement frequency for emissions-based site categories. Similar field sites were sorted into groups based on sitewide production rates and equipment counts, as detailed on Table 1.*

State-specific well count and production rate data, sorted by production rate category, were obtained from a U.S. Energy Information Administration database (EIA, 2020) for all oil and gas producing states except Indiana and Illinois. Comparable well counts and production rate distributions for Indiana and Illinois were derived from information published by IOGCC (2016) in addition to data for sites in those states represented in the operator survey database. For all states, the categorization of sites according to "size" (i.e., major equipment count) was primarily based on corresponding distributions of site size represented in the operator survey database, as neither the EIA database nor the IOGCC data reflect differences in this parameter. This assumption is subject to a high degree of uncertainty, however, as some states are not represented in the survey database, and the survey results may not accurately reflect the actual distribution of site sizes in some states. The handling of these and other uncertainties in this analysis is discussed further below.

Based on the classification criteria listed on Table 1 and applicable emission factors for the 22 site categories delineated in Figure 6, total annual methane emissions were estimated for each oil and gas producing state, based on i) the total number of sites in each category times a site count-based emission factor and ii) the total oil and gas production from sites in each category times a production-based emission factor. The resulting annual emission estimates for each category were summed and averaged, as appropriate, to yield statewide, regional, and nationwide total estimates for key site populations of interest, including marginal vs. nonmarginal gas wells and marginal vs. nonmarginal oil wells. The applicable emission factors used in these calculations are discussed in Section 5.2.2, and the values of those emission factors and related ranges of measurement uncertainty are presented on Table 4. An additional source of uncertainty evaluated in these calculations arises from the highly skewed distribution of measured emission rates (see Figure 7), which form the basis of the applied emission factors, and the possibly that a similar or even more highly skewed distribution exists among emissions that were detected but not successfully measured in the regional field campaigns.

The combined effects of the three sources of uncertainty described above were addressed by employing a Monte Carlo model to derive reasonable central, lower, and upper estimates for each state- and category-specific total emission calculation. The sensitivity of these estimates to a potentially highly skewed distribution of detected but unmeasured emissions was assessed by additional simulations. For each Monte Carlo simulation, 10,000 iterations were performed, varying a series of uniformly distributed random variables considering i) alternate reasonable state-specific assumptions regarding the distribution of site sizes, ii) the full range of measurement uncertainty associated with each applicable site category emission factor, and iii) alternate assumptions of moderate vs. high skewness in the rates of detected but unmeasured emissions in the regional field campaigns. The results of this analysis are presented and discussed in Section 5.4.

5.0 RESULTS AND DISCUSSION

5.1 Emissions Measurement Results

In Figure 7, plots of the 498 study-wide measured emission rates exhibit the long-tail behavior commonly observed in air emissions studies. In this study, approximately 90% of the observed methane emissions were less than 16 scfh (0.25 kg/h, 2.4 TPY) and 95% of the observed methane emissions were less than 38 scfh (0.60 kg/h, 5.8 TPY). Study wide, the top 10% of emitting sources contributed approximately 90% of the total methane emissions observed.

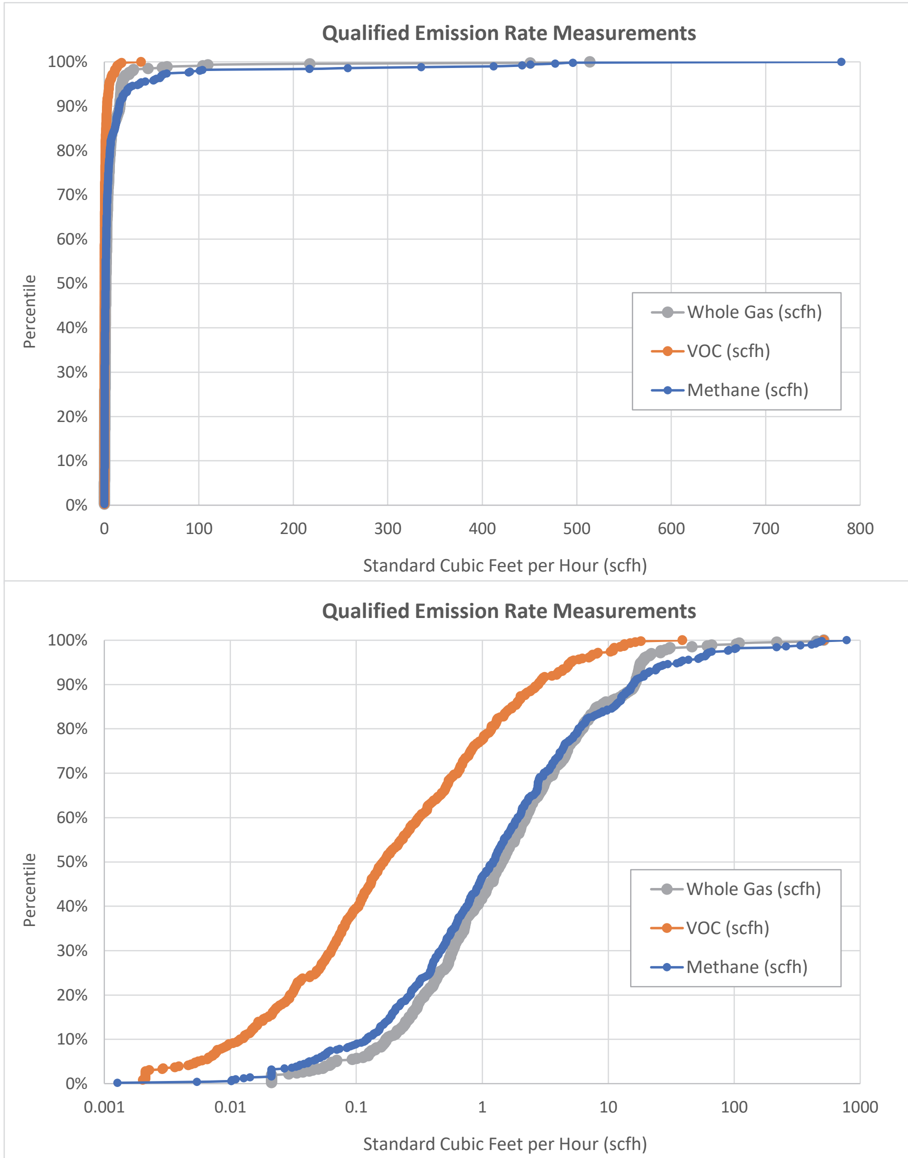


Figure 7. *Long-tail behavior observed in the study-wide measured emission rates. A small number of the emitters contributes a large portion of the emissions.*

Table 2 summarizes details of the 10 largest emissions measured among 613 emissions detected in the studied regions. Notably, four of these are related to general operational conditions, including the largest emission of 780 scfh (12 kg/h; 120 TPY) coming from an open top produced water tank, which accounted for 12% of study-wide observed methane emissions. Two corresponded to valves left open to allow wellhead surface casings to vent, and another to an open hole on the side of a well casing. Another eight emissions, ranging in magnitude from 2 to 90 scfh (0.0003 to 1.4 kg/h; 0.003 to 14 TPY) appeared related to general operation conditions or human factors rather than leaking or malfunctioning equipment.

Table 2. *Top 10 Largest Observed Emissions*

Rank	Methane Emission Rate (scfh)	(kg/h)	(tpy)	Emission Location	Emission Location Detail	Basin	Region2	Mech. or Oper. Issue?	Notes	Site type; Major equipment present
1	780	12	118	Tank	Produced water tank	Permian	Western US	Operational	open top tank	Nonmarginal oil, 1 wellhead, 6 separators, 9 tanks
2	499	7.8	76	Wellhead	Surface casing valve	Permian	Western US	Operational	open valve on wellhead	Marginal gas, 1 wellhead, 1 tank
3	486	7.6	74	Tank	Thief hatch	Permian	Western US	Mechanical	failing pressurized vent	Marginal oil tank battery, no wellhead, 2 separators, 1 meter, 4 tanks (2 emissions on separate tanks at same site)
4	460	7.2	70	Tank	Thief hatch	Permian	Western US	Mechanical	failing pressurized vent	
5	442	6.9	67	3-phase Separator	Water dump valve	Permian	Western US	Mechanical	malfunctioning pneumatic device	Nonmarginal oil "satellite", no wellhead, 4 separators, 2 meters, no tanks
6	437	6.9	66	Wellhead	Surface casing valve	Permian	Western US	Operational	open valve on wellhead	Marginal gas; 1 wellhead, 1 meter, 1 separator, 1 tank
7	337	5.3	51	3-phase Separator	Water dump valve	Permian	Western US	Mechanical	malfunctioning pneumatic valve	Nonmarginal oil "satellite", no wellhead, 3 separators, 3 meters, 1 compressor, no tanks
8	258	4.0	39	3-phase Separator	Water dump valve	Permian	Western US	Mechanical	malfunctioning pneumatic valve	Nonmarginal oil "satellite", no wellhead, 2 separators, 2 meters, no tanks
9	186	2.9	28	Wellhead	Surface casing	Appalachian	Eastern US	Operational	open hole on side of surface casing	Marginal gas, 1 wellhead, 1 meter
10	106	1.7	16	Wellhead	Sucker Rod Packing	Forest City	Eastern US	Mechanical	rod leaking during pumping	Marginal oil, well only

5.2 Total Emissions by Site

The precise definition and classification of an oil or natural gas production "site" proved challenging and could be subjective. For purposes of this study, the designation of a "site" generally denotes all equipment located together at a single contiguous well pad or physical location. During the field campaigns several locations were visited where multiple wells sharing a common tank battery were located relatively close to one another, but not on the same well pad (e.g., 20 wells spaced hundreds of feet apart over a 100-acre area). For purposes of data analysis, such locations were classified and counted separately as "small" sites due to a greater similarity of their characteristics with many other well-only sites visited, compared to "large" sites, where multiple wells were located on a single well pad. If the flow of production from a single wellhead continued offsite to a set of separators or tanks collecting fluid and/or gas from multiple wellheads on multiple pads, the pad and separation station sites were considered related, but separate.

5.2.1 Factors Most Strongly Correlated with Sitewide Methane Emissions

As noted above and described in detail in Appendix B, exploratory data analyses showed both the frequency of detected emissions and magnitude of methane and whole gas emissions among visited field sites to be most strongly correlated to the count of major equipment and secondarily correlated with site total oil and gas production rate. The correlation between major equipment count and site emission frequency (expressed as the number of detected emissions per piece of major equipment, i.e., not absolute count of emissions), was strong with the categorical site "size" variable and moderate (positive) with the numeric equipment count.

Among evaluated numeric variables, site equipment count also exhibited the strongest associations with both frequency and magnitude of sitewide emissions, exhibiting only a moderate positive correlation with detection frequency and weak associations with whole gas and methane emission rates. Weak correlations were also consistently detected among both the frequency and magnitude of emissions, total oil and gas production, and gas production rates.

5.2.2 Production Site Category Emission Profiles

Emission rates and factors can be considered in different ways, including: i) in absolute terms of the volume or mass of emissions per unit time, and ii) normalized relative to the rate of gas or oil produced in conjunction with a given emission. The latter of these can be considered a metric of methane intensity. In Figures 8 and 9, methane emission profiles in terms of both of these types of emission factor are compared among the 22 site categories shown in Figure 6. As described in Section 4.2, each category is characterized by a unique combination of production type (gas or oil), site size (in terms of major equipment count), and production rate bin. Additional details are presented on Table 4.

Figure 8 compares average emission factors for the full population of field sites in each category, i.e., all visited sites where emissions both were and were not detected. As such, these values account for the average frequency of detection as well as the average magnitude of detected emissions among all sites in each category. In contrast, Figure 9 shows average emissions among only those sites in each category where emissions were detected. The difference in these is analogous to the difference between population and "leaker" emissions factors in the EPA's Greenhouse Gas Reporting Program. On both charts, error bars reflect the propagation of uncertainty estimates associated with the emission measurements taken in this study, where the largest ranges of uncertainty are generally associated with downwind measurements of the largest emissions (see Appendix A).

These results are consistent with findings reported by others. For the Appalachian Basin, this study found average emission rates for sites producing less than 2 BOE/d to be 0.18 kg/h (1.7 TPY, 11 scfh) for small gas sites, 0.038 kg/h (0.37 TPY, 2.4 scfh) for small oil sites, and 0.075 kg/h (0.72 TPY, 4.8 scfh) overall for combined oil and gas sites. For comparison, Deighton et al. (2020) reported average methane emissions of 0.128 kg/h (1.24 TPY; 8.16 scfh) from 48 marginal and gas wells in Ohio, all producing less than 1 BOE/d, and Riddick et al (2019) report average methane emissions of 0.138 kg/h (1.33 TPY; 8.80 scfh) from 74 active conventional oil and gas wells in West Virginia.

5.2.3 Considerations Regarding Liquids Unloading

It is important to note that the results of this study correspond only to emissions observed at the time of each site visit and do not include episodic high emission events, such as liquids unloading or manual liquids removal. This process involves removing liquids from a gas producing well when a buildup of fluid has prevented the flow of gas at the wellhead. Although no liquids unloading events were observed during the site visits, they were reported by the host operators to occur at 118 of the 589 visited sites with various frequencies, as shown on Table 3.

Table 3. *Operator-Reported Frequency of Liquids Unloading Events at Visited Gas Production Sites.*

Reported Frequency	Approx. # per year	Number of Sites
As needed	unknown	84
Annually	1	8
Twice/year	2	5
Once/4 months	3	1
Quarterly	4	1
Once every few months	5	1
Once/2 months	6	5
Monthly	12	6
Twice/month	24	1
Weekly	52	5
Only during maintenance	<1	1

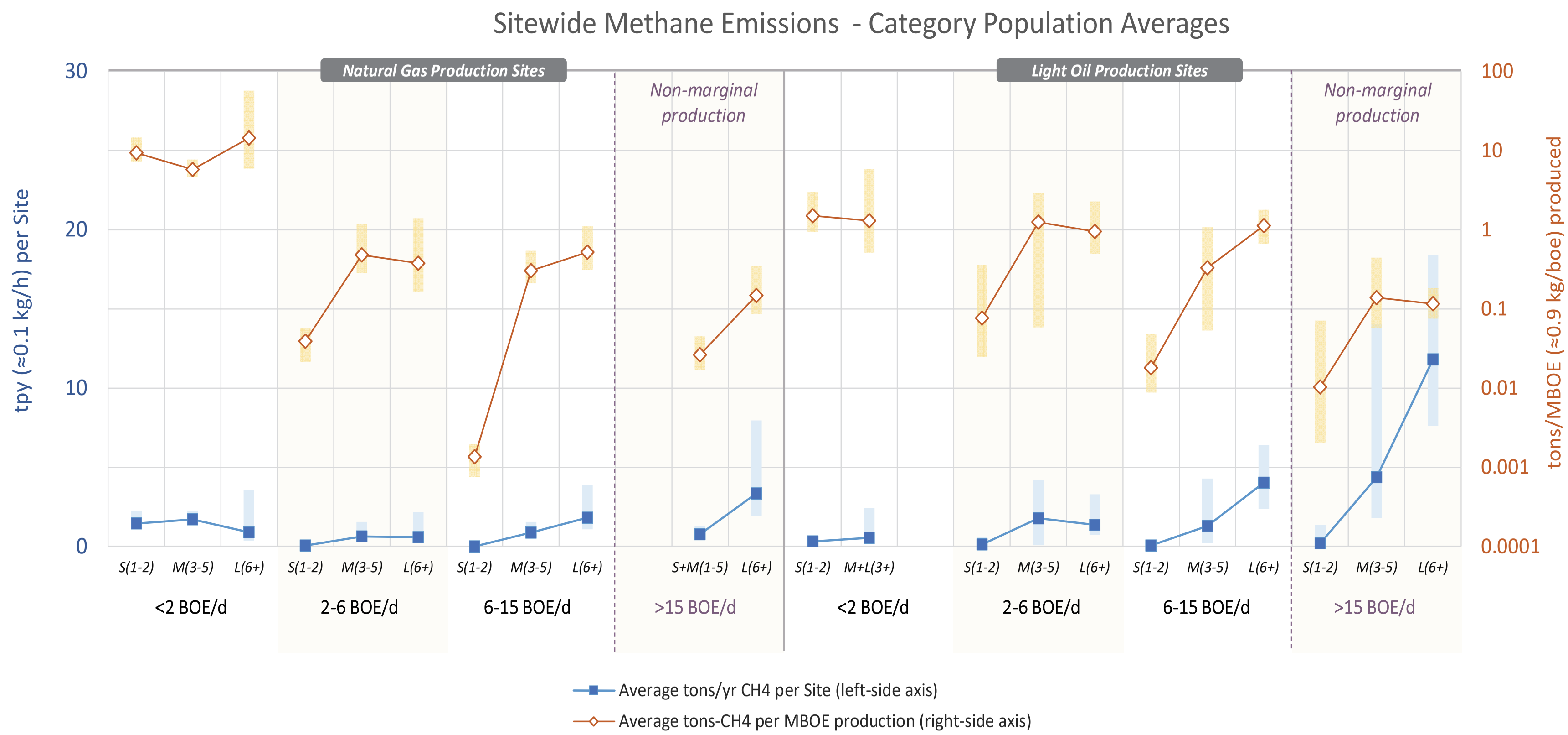


Figure 8. *Production site category emission profiles – Category Population Averages*

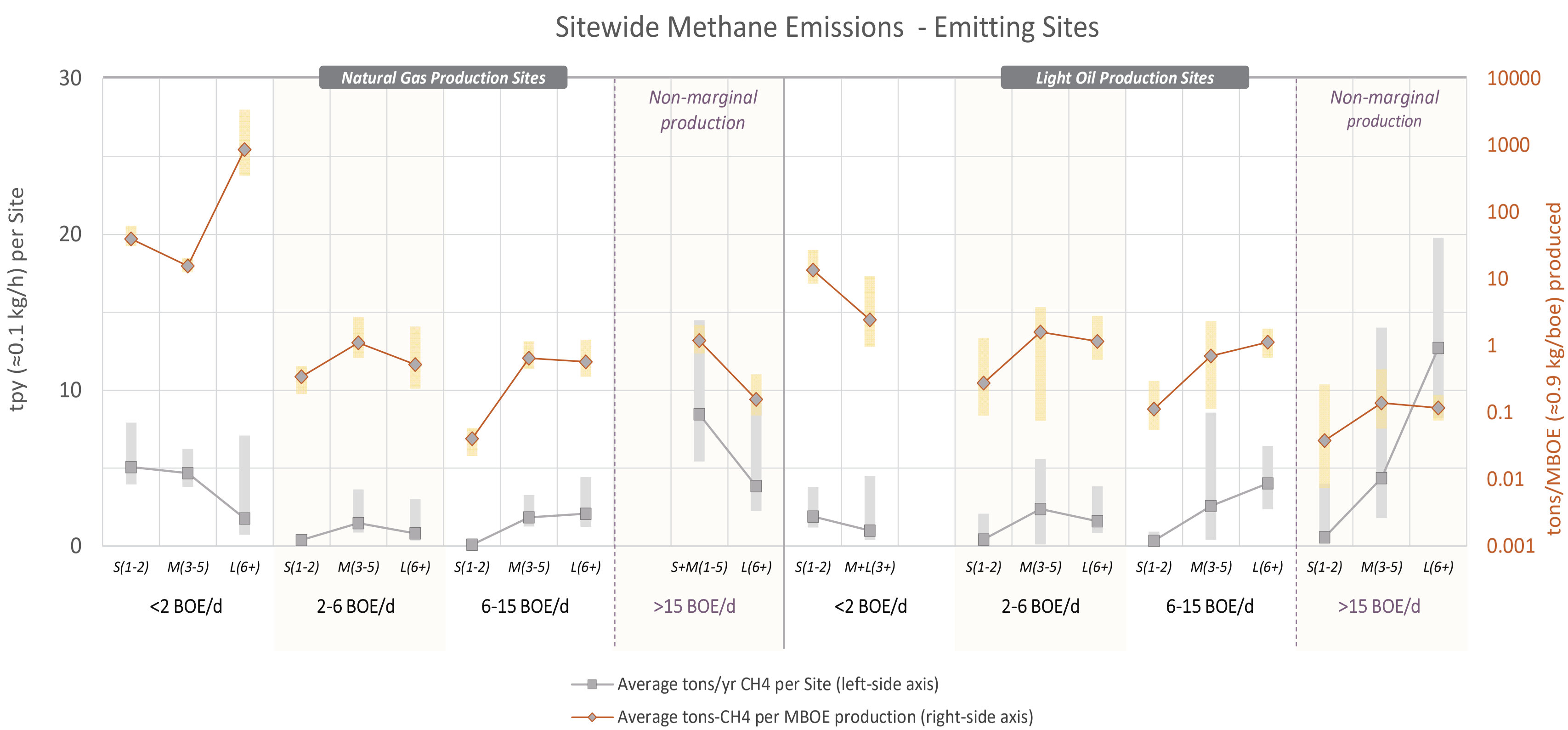


Figure 9. *Production site category emission profiles – Emitting Sites*

Table 4. *Site Category Population Summary*

bin		Production Category	Site Size (Equip. count)	#-sites		#-emissions		Avg. prod rate (boe/d)	Population Average - Site Count-Based						Population Average - Production Rate-Based					
				Visited	Emission Det.	Det.	Meas.		(kg/h/site)			(tpy/site)			(kg/boe)			(ton/MBOE)		
									Avg.	*minus*	*plus*	**Avg.**	*minus*	*plus*	**Avg.**	*minus*	*plus*	**Avg.**	*minus*	*plus*
1	**Natual gas sites**	boe_<2	S(1-2)	28	8	8	6	4.2E-1	1.5E-1	*3.3E-2*	*8.4E-2*	1.5E+0	*3.2E-1*	*8.1E-1*	8.5E+0	*1.9E+0*	*4.8E+0*	9.4E+0	*2.1E+0*	*5.2E+0*
2			M(3-5)	107	39	58	51	8.1E-1	1.8E-1	*3.4E-2*	*5.8E-2*	1.7E+0	*3.3E-1*	*5.6E-1*	5.2E+0	*1.0E+0*	*1.7E+0*	5.8E+0	*1.1E+0*	*1.9E+0*
3			L(6+)	10	5	20	18	1.7E-1	9.2E-2	*5.4E-2*	*2.8E-1*	8.9E-1	*5.2E-1*	*2.7E+0*	1.3E+1	*7.7E+0*	*3.9E+1*	1.4E+1	*8.4E+0*	*4.3E+1*
4		boe_2-6	S(1-2)	19	3	3	3	4.4E+0	6.5E-3	*2.9E-3*	*2.9E-3*	6.3E-2	*2.9E-2*	*2.8E-2*	3.6E-2	*1.6E-2*	*1.6E-2*	3.9E-2	*1.8E-2*	*1.8E-2*
5			M(3-5)	40	17	25	22	3.6E+0	6.5E-2	*2.7E-2*	*9.5E-2*	6.3E-1	*2.6E-1*	*9.2E-1*	4.3E-1	*1.8E-1*	*6.3E-1*	4.8E-1	*2.0E-1*	*7.0E-1*
6			L(6+)	18	13	34	30	4.3E+0	6.1E-2	*3.4E-2*	*1.6E-1*	5.9E-1	*3.3E-1*	*1.6E+0*	3.4E-1	*1.9E-1*	*9.2E-1*	3.8E-1	*2.1E-1*	*1.0E+0*
7		boe_6-15	S(1-2)	21	1	1	1	9.0E+0	4.6E-4	*2.1E-4*	*2.0E-4*	4.5E-3	*2.0E-3*	*2.0E-3*	1.2E-3	*5.5E-4*	*5.4E-4*	1.4E-3	*6.1E-4*	*6.0E-4*
8			M(3-5)	21	10	20	20	7.9E+0	9.1E-2	*2.8E-2*	*7.1E-2*	8.8E-1	*2.7E-1*	*6.8E-1*	2.8E-1	*8.6E-2*	*2.1E-1*	3.0E-1	*9.5E-2*	*2.4E-1*
9			L(6+)	32	28	115	106	9.6E+0	1.9E-1	*7.6E-2*	*2.1E-1*	1.8E+0	*7.4E-1*	*2.1E+0*	4.7E-1	*1.9E-1*	*5.3E-1*	5.2E-1	*2.1E-1*	*5.9E-1*
10		boe_>15	M(3-5)	11	1	3	3	8.0E+1	8.0E-2	*2.9E-2*	*5.7E-2*	7.7E-1	*2.8E-1*	*5.5E-1*	2.4E-2	*8.6E-3*	*1.7E-2*	2.6E-2	*9.5E-3*	*1.9E-2*
11			L(6+)	30	26	132	116	6.2E+1	3.5E-1	*1.5E-1*	*4.8E-1*	3.3E+0	*1.4E+0*	*4.6E+0*	1.3E-1	*5.7E-2*	*1.9E-1*	1.5E-1	*6.2E-2*	*2.0E-1*
12	**Oil sites**	boe_<2	S(1-2)	76	13	13	9	5.9E-1	3.4E-2	*1.3E-2*	*3.4E-2*	3.3E-1	*1.2E-1*	*3.2E-1*	1.4E+0	*5.1E-1*	*1.4E+0*	1.5E+0	*5.6E-1*	*1.5E+0*
13			M(3-5)	13	7	10	3	1.1E+0	5.6E-2	*3.4E-2*	*2.0E-1*	5.4E-1	*3.3E-1*	*1.9E+0*	1.2E+0	*7.1E-1*	*4.1E+0*	1.3E+0	*7.9E-1*	*4.5E+0*
14		boe_2-6	S(1-2)	35	10	11	6	4.5E+0	1.3E-2	*8.8E-3*	*4.9E-2*	1.3E-1	*8.5E-2*	*4.7E-1*	6.9E-2	*4.7E-2*	*2.6E-1*	7.7E-2	*5.2E-2*	*2.9E-1*
15			M(3-5)	8	6	11	2	3.9E+0	1.8E-1	*1.8E-1*	*2.5E-1*	1.8E+0	*1.7E+0*	*2.4E+0*	1.1E+0	*1.1E+0*	*1.5E+0*	1.2E+0	*1.2E+0*	*1.7E+0*
16			L(6+)	14	12	27	18	4.0E+0	1.4E-1	*6.7E-2*	*2.0E-1*	1.4E+0	*6.5E-1*	*1.9E+0*	8.6E-1	*4.1E-1*	*1.2E+0*	9.5E-1	*4.5E-1*	*1.3E+0*
17		boe_6-15	S(1-2)	24	4	4	2	8.7E+0	6.0E-3	*3.1E-3*	*9.9E-3*	5.8E-2	*3.0E-2*	*9.6E-2*	1.6E-2	*8.5E-3*	*2.7E-2*	1.8E-2	*9.4E-3*	*3.0E-2*
18			M(3-5)	8	4	8	2	1.1E+1	1.3E-1	*1.1E-1*	*3.1E-1*	1.3E+0	*1.1E+0*	*3.0E+0*	3.0E-1	*2.5E-1*	*6.9E-1*	3.3E-1	*2.8E-1*	*7.6E-1*
19			L(6+)	9	9	24	19	9.8E+0	4.2E-1	*1.7E-1*	*2.5E-1*	4.0E+0	*1.7E+0*	*2.4E+0*	1.0E+0	*4.2E-1*	*6.1E-1*	1.1E+0	*4.6E-1*	*6.7E-1*
20		boe_>15	S(1-2)	15	5	5	1	5.1E+1	2.0E-2	*1.6E-2*	*1.2E-1*	1.9E-1	*1.6E-1*	*1.1E+0*	9.4E-3	*7.6E-3*	*5.5E-2*	1.0E-2	*8.3E-3*	*6.1E-2*
21			M(3-5)	1	1	4	4	8.6E+1	4.5E-1	*2.7E-1*	*1.0E+0*	4.4E+0	*2.6E+0*	*9.7E+0*	1.3E-1	*7.4E-2*	*2.8E-1*	1.4E-1	*8.1E-2*	*3.1E-1*
22			L(6+)	14	13	45	36	2.8E+2	1.2E+0	*4.3E-1*	*6.8E-1*	1.2E+1	*4.2E+0*	*6.6E+0*	1.1E-1	*3.7E-2*	*5.9E-2*	1.2E-1	*4.1E-2*	*6.5E-2*

5.3 Equipment-Specific Emissions

As discussed in Section 4.1.2, during the field campaigns, separators, wellheads, and tanks were by far the most common equipment encountered for all types of sites and exhibited the largest volumes of emissions. Meters were commonly encountered at natural gas sites with a much lower emission frequency, and a small number of compressors was also encountered, with a majority of those exhibiting one or more discrete emissions. Table 5 summarizes the types and numbers of all major equipment encountered at the visited sites, the frequency of detected emissions and the average magnitude of emissions among i) emitting equipment only, representing effective "leaker" emissions in the parlance of the EPA Greenhouse Gas Reporting Program, and ii) the full population of observed equipment representing effective population emission factors. These results are presented separately for oil vs. natural gas sites and for the study as a whole vs. regionally for Eastern and Western US, consistent with such breakdowns in the GHGRP, as well as for this study as a whole.




While not every type of equipment where emissions were ultimately detected (such as combustors and glycol heaters) were specifically tallied at every site, Table 5 summarizes the observed emissions at the most commonly seen equipment types and the equipment types identified as the largest or more common sources of emissions. Note, the high frequency of emissions for certain equipment (e.g., >100% among 3-phase separators) reflects the rather frequent observation of multiple emissions on a single unit of equipment and does not mean that emissions were detected from every observed unit. There were occasions where distinct emissions were observed among separate components on the same separator. Nine emissions were attributed to yard piping rather than a specific piece of equipment. These ranged from 0.22 scfh (0.0035 kg/h, 0.033 TPY) to 19 scfh (0.30 kg/h, 2.9 TPY) from small threaded connectors and regulators and were 16 scfh (0.25 kg/h, 2.4 TPY) and 89 scfh (1.4 kg/h, 13 TPY) from an underground line and a pipe manifold building, respectively. Equipment-specific exploratory analyses are described in detail in Appendix B and summarized as follows.

- ***Separator emissions:*** Emission detection frequency is strongly associated with the number of phases (2 or 3) of the separator and site production rates, corresponding to throughput. Maximum and operational design pressures exhibited a strong to moderate association with emission detection frequencies but not magnitude.
- ***Wellhead emissions:*** Only weak associations were apparent between emission detection frequency and evaluated wellhead characteristics. The strongest of these were with host operator, basin, well depth (possibly a proxy for wellhead casing pressure), and gas production rate. Notably, well type and age did not exhibit significant association with either emission frequency or magnitude.
- ***Tank emissions:*** Only weak associations were found between emission detection frequency and evaluated tank characteristics. The strongest of these were with the presence of pressurized or atmospheric vents, oil production rate, and liquid level.

Table 5. *Frequency and Magnitude of Equipment Specific Emissions*

Region / Equipment	Equipment Observed	Emissions Detected	Detection frequency	Emissions Quantified	Avg. Methane Emission Rate						Equipment Observed	Emissions Detected	Detection frequency	Emissions Quantified	Avg. Methane Emission Rate					
					Emitting Equipment			Population Avg.							Emitting Equipment			Population Avg.		
	(#)	(#)	(%)	(#)	(scfh)	(kg/h)	(tpy)	(scfh)	(kg/h)	(tpy)	(#)	(#)	(%)	(#)	(scfh)	(kg/h)	(tpy)	(scfh)	(kg/h)	(tpy)
Eastern US	**Natural Gas Sites**										**Light Oil Sites**									
Compressor	4	1	25%	1	14	0.21	2.1	3.4	0.054	0.52	2	0	0%	0	--	--	--	--	--	--
Dehydrator	2	0	0%	0	--	--	--	--	--	--	0	0	--	0	--	--	--	--	--	--
Meter	167	4	2%	3	1.7	0.026	0.25	0.040	0.00063	0.0061	14	2	14%	2	0.52	0.0081	0.078	0.074	0.0012	0.011
Separator	127	14	11%	12	1.6	0.025	0.24	0.17	0.0027	0.026	35	4	11%	1	19	0.30	2.9	2.2	0.035	0.33
2-phase	125	13	10%	11	0.99	0.016	0.15	0.10	0.0016	0.016	20	1	5%	0	--	--	--	--	--	--
3-phase	0	0	--	0	--	--	--	--	--	--	15	3	20%	1	19	0.30	2.9	3.9	0.061	0.59
Tank	155	17	11%	15	14	0.22	2.2	1.6	0.025	0.24	82	25	30%	16	3.3	0.051	0.50	1.0	0.016	0.15
thief hatch	149	3	2%	3	34	0.54	5.2	0.69	0.011	0.10	84	9	11%	7	3.5	0.055	0.53	0.37	0.0059	0.057
vent	176	14	8%	12	9.3	0.15	1.4	0.74	0.012	0.11	29	16	55%	9	3.1	0.049	0.47	1.7	0.027	0.26
Wellhead	159	31	19%	27	11	0.17	1.7	2.1	0.034	0.32	95	15	16%	8	17	0.27	2.6	2.8	0.043	0.42
Yard piping	--	3	--	3	8.0	0.13	1.2	--	--	--	--	0	--	0	--	--	--	--	--	--
Western US	**Natural Gas Sites**										**Light Oil Sites**									
Compressor	18	20	111%	20	15	0.24	2.3	17	0.27	2.6	17	9	53%	8	6.8	0.11	1.0	3.6	0.056	0.54
Dehydrator	10	0	0%	0	--	--	--	--	--	--	0	0	--	0	--	--	--	--	--	--
Flare	6	2	33%	1	19	0.30	2.9	6.4	0.10	0.97	13	2	15%	2	39	0.60	5.8	5.9	0.093	0.90
Meter	185	6	3%	5	1.5	0.024	0.23	0.050	0.00078	0.0075	80	3	4%	1	0.15	0.0024	0.023	0.0058	0.000090	0.00087
Separator	191	198	104%	187	2.3	0.036	0.35	2.4	0.038	0.36	133	40	30%	28	42	0.66	6.4	13	0.20	1.9
2-phase	73	29	40%	25	3.4	0.053	0.51	1.3	0.021	0.20	41	11	27%	9	6.6	0.10	0.99	1.8	0.028	0.27
3-phase	114	169	148%	162	2.2	0.034	0.33	3.2	0.050	0.48	82	27	33%	18	62	0.97	9.4	20	0.32	3.1
Tank	340	71	21%	56	5.5	0.087	0.84	1.2	0.018	0.17	189	55	29%	35	58	0.90	8.7	17	0.26	2.5
thief hatch	222	48	22%	38	3.4	0.053	0.51	0.73	0.011	0.11	159	33	21%	23	47	0.73	7.1	9.7	0.15	1.5
vent	103	6	6%	5	0.92	0.014	0.14	0.053	0.00084	0.0081	13	13	100%	6	4.7	0.073	0.71	4.7	0.073	0.71
open top	1	1	100%	0	--	--	--	--	--	--	2	2	100%	2	435	6.8	66	435	6.8	66
Emiss. control dev.	15	5	33%	3	23	0.36	3.5	7.6	0.12	1.2	6	1	17%	1	15	0.24	2.3	2.5	0.039	0.38
Wellhead	260	46	18%	41	26	0.41	4.0	4.6	0.073	0.70	118	30	25%	14	2.6	0.041	0.40	0.7	0.010	0.10
Yard piping	--	2	--	2	9.2	0.14	1.4	--	--	--	--	4	--	3	31	0.48	4.7	--	--	--
Study Total	**Natural Gas Sites**										**Light Oil Sites**									
Compressor	22	21	95%	21	15	0.24	2.3	15	0.23	2.2	19	9	47%	8	6.8	0.11	1.0	3.2	0.050	0.49
Dehydrator	12	0	0%	0	--	--	--	--	--	--	0	0	0%	0	--	--	--	--	--	--
Flare	6	2	33%	1	19	0.30	2.9	6.4	0.10	0.97	13	2	15%	2	39	0.60	5.8	5.9	0.093	0.90
Meter	352	10	3%	8	1.6	0.025	0.24	0.045	0.00071	0.0068	94	5	5%	3	0.40	0.0062	0.060	0.021	0.00033	0.0032
Separator	318	212	67%	199	2.3	0.036	0.34	1.5	0.024	0.23	168	44	26%	29	42	0.65	6.3	11	0.17	1.7
2-phase	198	42	21%	36	2.6	0.041	0.40	0.56	0.0088	0.085	61	12	20%	9	6.6	0.10	0.99	1.3	0.020	0.20
3-phase	114	169	148%	162	2.2	0.034	0.33	3.2	0.050	0.48	97	30	31%	19	60	0.94	9.0	18	0.29	2.8
Tank	495	88	18%	71	7.4	0.12	1.1	1.3	0.021	0.20	271	80	30%	51	41	0.64	6.2	12	0.19	1.8
thief hatch	371	51	14%	41	5.6	0.089	0.86	0.78	0.012	0.12	243	42	17%	30	37	0.58	5.6	6.3	0.099	0.96
vent	279	20	7%	17	6.8	0.11	1.0	0.49	0.0077	0.074	42	29	69%	15	3.7	0.059	0.57	2.6	0.040	0.39
open top	1	1	100%	0	--	--	--	--	--	--	2	2	100%	2	--	--	--	--	--	--
Emiss. control dev.	15	5	33%	3	23	0.36	3.5	7.6	0.12	1.2	6	1	17%	1	15	0.24	2.3	2.5	0.039	0.38
Wellhead	419	77	18%	68	20	0.32	3.1	3.7	0.058	0.56	213	45	21%	22	8.0	0.13	1.2	1.7	0.027	0.26
Yard piping	--	5	--	5	8.5	0.13	1.3	--	--	--	--	4	--	3	31	0.48	4.7	--	--	--

5.4 Relative Magnitude and Extent of O&G Production-Related Methane Emissions

Figures 10a and 10b summarize the results of Monte Carlo simulations used to estimate state-specific annual methane emissions estimates marginal vs. nonmarginal oil and gas production operations. As described in Section 4.3, these account for observed and reported regional differences in production types and rates, site characteristics including size (i.e., major equipment counts), equipment types, frequency and magnitude of emissions and related uncertainties. Sensitivity analyses found that assuming the distribution of detected but unmeasured emissions was very highly skewed versus moderately skewed would increase all of these estimates by approximately 1%. On each plot in Figures 10a and 10b, the x-axis represents total estimated methane emissions, in TPY, based on the reported number of wells in each state, and the y-axis represents corresponding estimates, based on the reported oil and gas production in each state. The 95% confidence interval of each result is less than 2% for marginal production and less than 3% for nonmarginal production.

As shown by the distribution of points around each 1:1 diagonal, estimates by the separate estimates generally agree, especially for marginal production. However, for nonmarginal oil production the site count-based estimates is notably larger than the production-based estimate for most states. The reason for this is not clear; however, it could at least partially be due to an overestimation of “site” counts, assumed equal to well counts for nonmarginal categories. Greater scatter exhibited in the results for nonmarginal production is likely due to multiple factors. Figure 8 and Table 4 show that applicable emission factors for the five nonmarginal site categories exhibit much greater ranges of measurement uncertainty than the to 17 marginal site categories. Additionally, nonmarginal production represented only a small proportion (~10%) of sites visited in the regional field campaigns, consistent with the focus and design of this study; however, these exhibited a much larger range of production rates and major equipment counts than marginal production sites and a disproportionate number (~30%) of detected but unmeasured emissions, resulting in even greater uncertainty.

Figures 11 and 12, provide additional perspectives on these results for comparison. As it is impossible to know for a given state whether the site count-based or production-based estimate is more accurate or reliable, the average of these considered the most reasonable estimates, as represented in the bar charts and largest pie charts. Overall, the comprehensive results of this study suggest that i) marginal oil and gas production in the United States may account for approximately 1 million (±140,000) TPY of “every day” methane emissions, as were observed in the regional field campaigns, ii) marginal gas production accounts for an estimated 60% (±10%) of emissions from U.S. natural gas production, and iii) marginal oil production accounts for an estimated 40% (±10%) of emissions from U.S. oil production. Table 6 presents additional details of these findings.

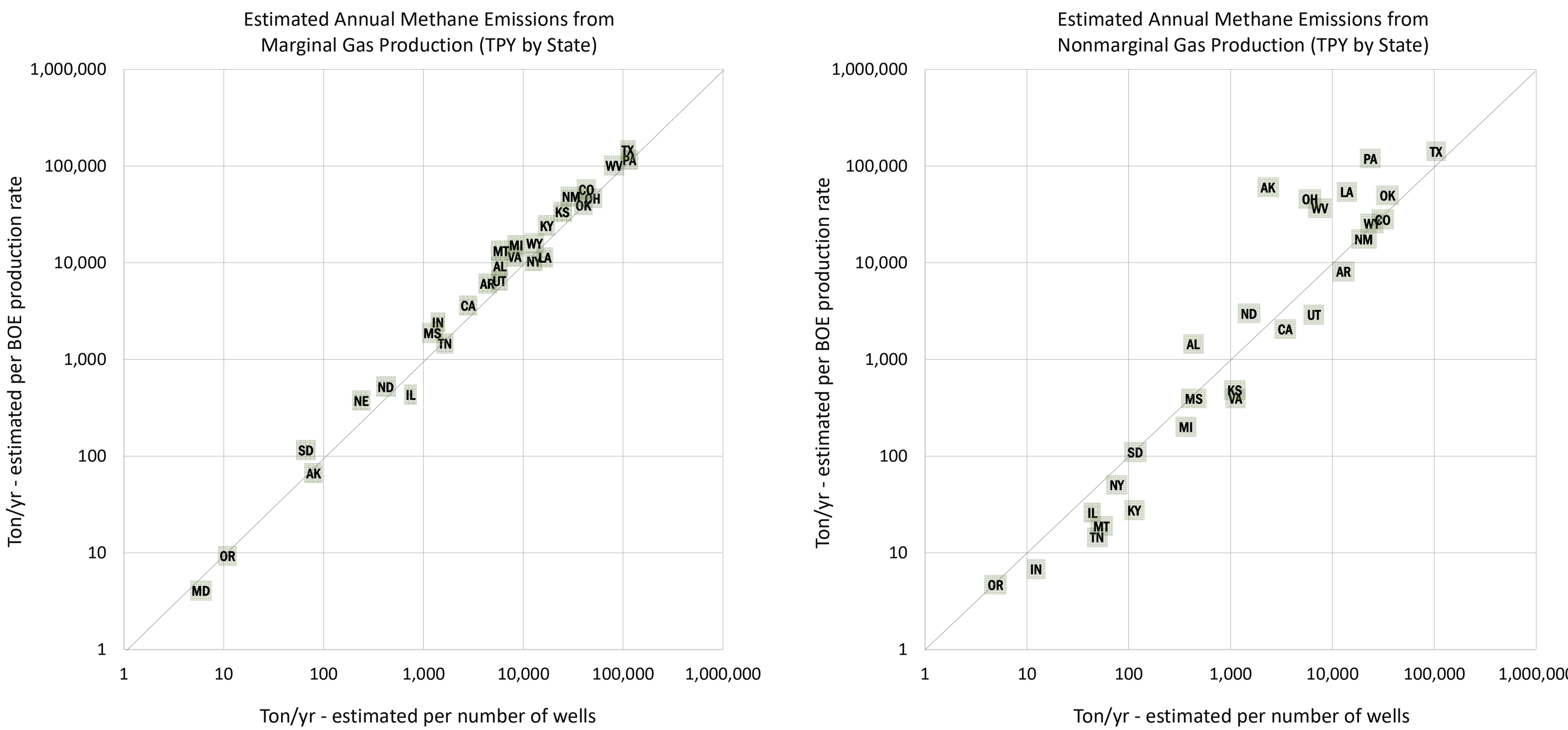
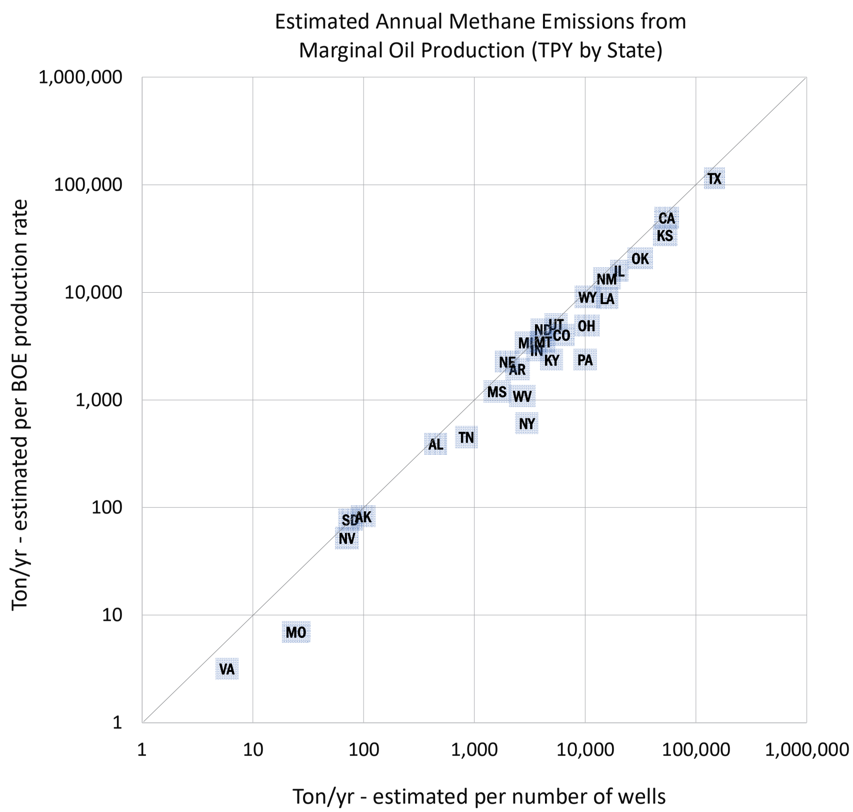


Figure 10(a). *Estimated annual methane emissions by state: Marginal and nonmarginal gas production.*



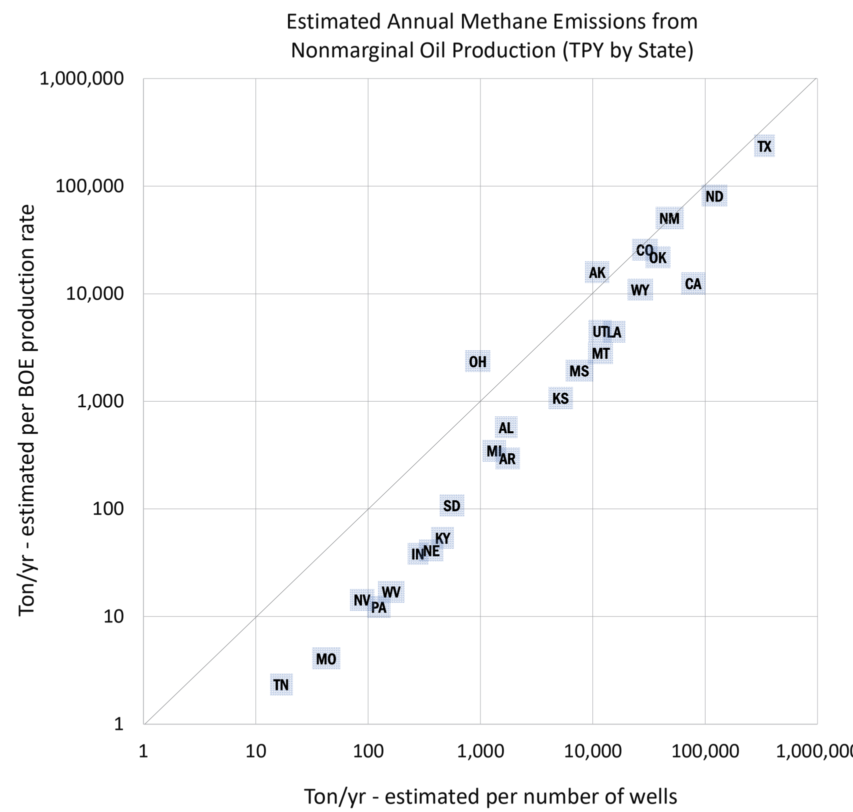


Figure 10(b). *Estimated annual methane emissions by state: Marginal and nonmarginal oil production.*

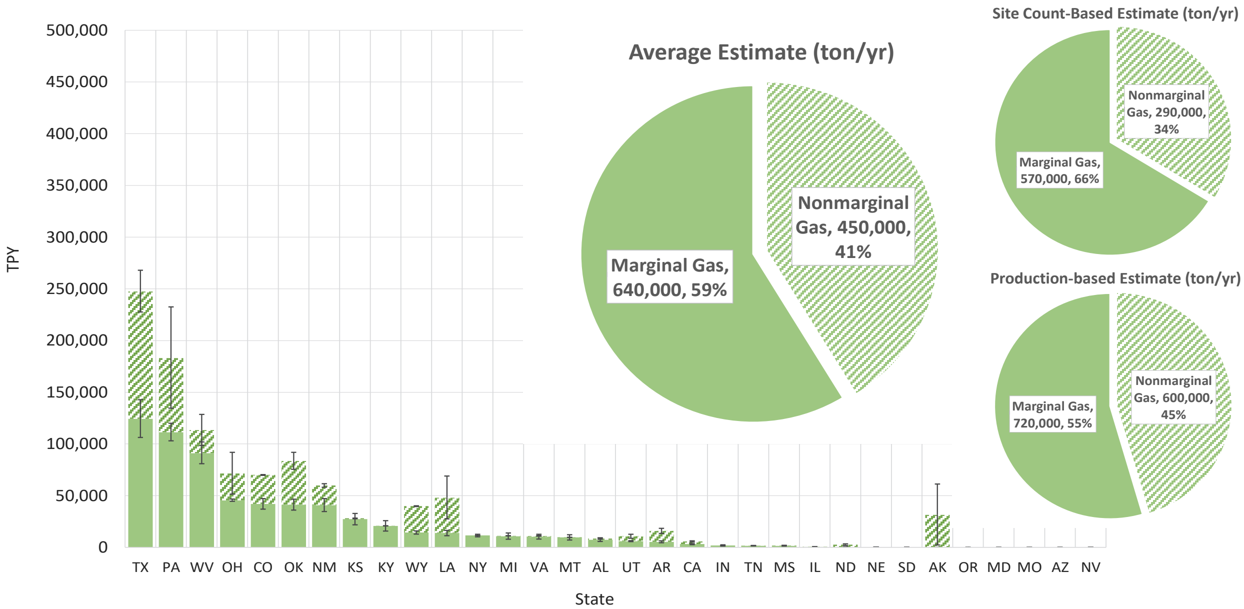


Figure 11. *Estimated overall methane emissions from marginal and nonmarginal gas production.*

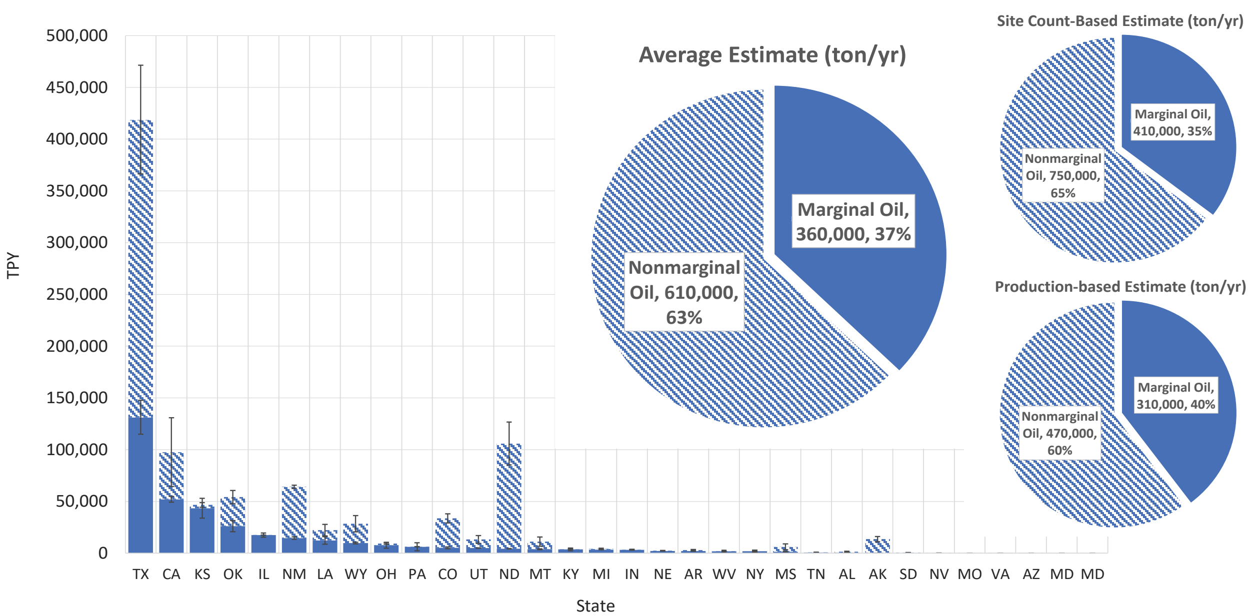


Figure 12. *Estimated overall methane emissions from marginal and nonmarginal oil production.*

Table 6. *Relative Estimated Methane Emissions from Marginal and Nonmarginal O&G Production*

	Approx. Well Count		Annual Production		Estimated Cumulative Methane Emissions			Avg. Pop. Emission Factors	
	count	share	boe/yr	share	ton/yr	Tg/yr	share	tons/yr/well	ton/MBOE
Natural Gas Production									
Marginal	420,000	78%	4.6E+8	7%	640,000 ±80,000	0.58 ±0.08	59% ±12%	1.5 ±0.2	1.4 ±0.2
Nonmarginal	120,000	22%	5.8E+9	93%	450,000 ±170,000	0.41 ±0.16	41% ±12%	3.7 ±1.4	0.077 ±0.030
total gas	*540,000*	*100%*	*6.2E+9*	*100%*	*1,090,000 ±260,000*	*0.99 ±0.23*	*100%*	*2.0 ±0.5*	*0.18 ±0.04*
Oil Production									
Marginal	363,000	80%	3.2E+8	8%	360,000 ±50,000	0.33 ±0.05	37% ±9%	1.0 ±0.1	1.1 ±0.2
Nonmarginal	88,000	20%	3.9E+9	92%	610,000 ±150,000	0.55 ±0.14	63% ±9%	7.0 ±1.7	0.16 ±0.04
total oil	*451,000*	*100%*	*4.2E+9*	*100%*	*970,000 ±210,000*	*0.88 ±0.19*	*100%*	*2.2 ±0.5*	*0.23 ±0.05*
Combined Oil & Gas Production									
Marginal	783,000	79%	7.7E+8	7%	1,000,000 ±140,000	0.91 ±0.13	49% ±11%	1.3 ±0.2	1.3 ±0.2
Nonmarginal	208,000	21%	9.6E+9	93%	1,060,000 ±320,000	0.96 ±0.29	51% ±11%	5.1 ±1.6	0.11 ±0.03
total oil & gas	*991,000*	*100%*	*1.0E+10*	*100%*	*2,060,000 ±460,000*	*1.87 ±0.42*	*100%*	*2.1 ±0.5*	*0.20 ±0.04*

Figure 13 summarizes the estimated geographic distribution of overall methane emissions from marginal oil and gas production across the US. This analysis indicates that the Appalachian Basin produces the largest volume of marginal production-related methane emissions from any single geologic basin, with an estimated 290,000 TPY coming from Pennsylvania, West Virginia, and Ohio, New York, Maryland, and Virginia representing 29% of methane emissions from US marginal oil and gas production. Texas, Oklahoma, and New Mexico, which encompass the Permian plus large parts of the Anadarko, San Juan, and other basins, together emit an estimated 380,000 TPY of methane (38%).

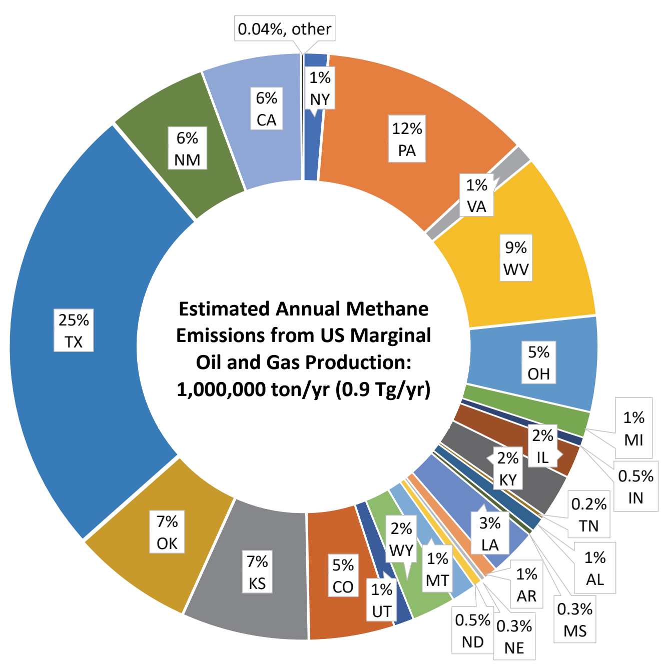


Figure 13. *Estimated regional distribution of methane emissions from US marginal oil and gas production.*

6.0 ACKNOWLEDGMENTS

6.1 Technical Advisory Steering Committee

There has been a high level of interest and participation on this project from industry and regulatory stakeholders concerned with quantification of methane emissions from marginal oil and gas wells. A Technical Advisory Steering Committee (TASC) was established and implemented to provide input and feedback on key aspects of the project work scope. The TASC was tiered, with a full committee that included representation from industry, regulators, non-government organizations, and academia, and a sub-committee comprised of industry representatives only. The industry sub-committee played a major role during the initial data assessment and master workplan development. Subsequently, the full TASC was engaged to ensure site selection, regional workplans, measurement technologies, and data measurement and analysis approaches were adequately addressed to meet stakeholder requirements and QA/QC standards. The TASC convened on four occasions as follows:

- ***April 2019:*** Four calls covering identical topics were held to introduce the project, discuss the preliminary literature review, planning of the operator data survey, and proposed field strategy.
- ***August 2019:*** Four calls covering identical topics were held to discuss the results and findings of the Data Source Status Assessment Report and draft Master Workplan, including site selection criteria and procedures for the subsequent field investigations. The research team incorporated extensive TASC feedback in preparation of the Regional Field Workplans.
- ***March 2020:*** Two calls covering identical topics were held to discuss preliminary results and findings from Field Campaign 1 and plans for Field Campaign 2.
- ***September 2021:*** Two calls covering identical topics were held to discuss preliminary results and findings from Field Campaigns 2 and 3 and plans for comprehensive data analyses.

Recurring engagement and open communication with the TASC provided excellent opportunities for the GSI and CSU project team to inform key stakeholders of project plans and findings and for TASC participants to increase project efficiency by providing timely feedback on sampling protocols, data analysis, interpretation of findings, and review of preliminary draft reports. The researchers gratefully acknowledge the interest and participation all TASC members, with special thanks to participants who engaged actively with the research team through constructive dialog and discussions and provided concrete, unbiased input and feedback.

6.2 Operator Survey Respondents and Facilitators

Effective design and planning of the regional field campaigns and the extrapolation of results for comparison of nationwide marginal and nonmarginal production-related emissions was largely made possible by a wealth of data contributed by respondents to the confidential, data-blinded operator survey conducted at the beginning of this project. The research team gratefully acknowledges all respondents who took time to complete and return the survey questionnaire in addition to multiple cooperating industry organizations throughout the country, who widely disseminated the questionnaire and encouraged their membership and others to support this study.

6.3 Field Site Host Operators and Escorts

Effective planning and execution of the field campaigns and the interpretation of results would not have been possible without access to field sites and supplemental activity data graciously and generously contributed by 15 host operators. These companies cooperated extensively with the research team under binding agreements that ensured protections for the integrity of the project, unbiased selection of field sites, host anonymity outside of the project team, and data blinding of company confidential and proprietary information, including all identifying information on specific field sites. The researchers gratefully acknowledge the assistance of dozens of individuals with these companies, from corporate executive, administrative, and EH&S personnel to regional field superintendents, local well pumpers and supervisors, whose knowledge, experience, insights, advice, and tremendous cooperation with the project team were invaluable.

6.4 Project Funders

The project was primarily funded under an assistance agreement with U.S. Department of Energy, Office of Fossil Energy, and managed by the National Energy Technology Laboratory (NETL). Supplemental funding was provided by the American Petroleum Institute (API), the Michigan Oil and Gas Association, the Indiana Oil & Gas Association, the Illinois Oil & Gas Association, the Kansas Independent Oil and Gas Association, the University of Texas System-University Lands, and other private contributors.

7.0 REFERENCES

Bluestein, B. J., Mallya, H., Yandoli, L., Polchert, M., & Amarin, N. (2015). Methane Emissions from the Oil and Gas Industry: "Making Sense of the Noise." ICF White Paper. https://www.icf.com/resources/white-papers/2015/methane-emissions-from-the-oil-and-gas-industry

Deighton, J.A., A. Townsend-Small, S. J. Sturmer, J. Hoschouer & L. Heldman (2020) Measurements show that marginal wells are a disproportionate source of methane relative to production, Journal of the Air & Waste Management Association, 70:10, 1030-1042, DOI: 10.1080/10962247.2020.1808115

Environmental Commenters (2018). Comments on behalf of Environmental Defense Fund, Chesapeake Bay Foundation, Clean Air Council, Clean Air Task Force, Center for Biological Diversity, Earthjustice, Earthworks, Environmental Integrity Project, Environmental Law & Policy Center, National Parks Conservation Association, Natural Resources Defense Council, and Sierra Club," December 17,2018, EPA Docket ID No. EPA-HQ-OAR-2017-0483. https://www.edf.org/sites/default/files/content/Joint_Environmental_Comments_on_EPAs_Proposed_NSPS_Reconsideration.pdf

EIA (2020). The Distribution of U.S. Oil and Natural Gas Wells by Production Rate, December 2020, U.S. Energy Information Administration, Washington, DC https://www.eia.gov/petroleum/wells/pdf/full_report.pdf

EPA (2018). Memorandum: Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa, April 12, 2018, EPA Docket ID No. EPA-HQ-OAR-2017-0483. https://www.epa.gov/sites/production/files/2018-09/documents/equivalency_of_state_fugitive_emissions_programs_for_well_sites_and_compressor_stations.pdf

GSI (2019a). Data Source Status Assessment Report and Master Workplan, US DOE NETL Award Number DE-FE0031702, 30 September 2019, GSI Environmental Inc., Austin, Texas.

GSI (2019b). Regional Field Workplan, US DOE NETL Award Number DE-FE0031702, 23 October 2019, GSI Environmental Inc., Austin, Texas.

GSI (2020). Regional Field Campaigns Workplan, US DOE NETL Award Number DE-FE0031702, 23 October 2020 (updated 8 April 2021), GSI Environmental Inc., Austin, Texas.

IOGCC (2016). Marginal Wells: Fuel for Economic Growth, Interstate Oil & Gas Compact Commission. http://iogcc.ok.gov/Websites/iogcc/images/MarginalWell/Marginal%20Well%202016%20-%20FINAL.pdf

McVay , R. and K. Roberts (2018). Assessment of State-Level Fugitive Emissions Programs in Comparison to EPA NSPS Reconsideration Proposal, December 17, 2018, Environmental Defense Fund, Austin, Texas. https://www.edf.org/sites/default/files/content/Appendix_A_McVay_and_Roberts_Assessment_of_State-Level_Fugitives_Emiss....pdf

Omara, M., Zimmerman, N., Sullivan, M. R., Li, X., Ellis, A., Cesa, R., Subramanian, R., Presto, A. A. & Robinson, A. L. (2018). Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, *Environmental Science & Technology* 2018 52 (21), 12915-12925. DOI: 10.1021/acs.est.8b03535.

Riddick, Stuart N., Denise L. Mauzerall, Michael A. Celia, Mary Kang, Kara Bressler, Christopher Chu, and Caleb D. Gum. “Measuring methane emissions from abandoned and active oil and gas wells in West Virginia.” Science of the Total Environment 651, no. 2 (2019): 1849-1856.

APPENDIX A

Field Measurement Data Reduction

APPENDIX A
Field Measurement Data Reduction

Field measurements to quantify methane and/or VOC emissions at marginal well sites were made using both onsite, direct, and downwind measurements. Sources identified onsite during Optical Gas Imaging (OGI) surveys were measured directly using a Bacharach Hi-Flow Sampler (Hi-Flow) that was specially modified to enable canister samples to be drawn from the inlet flow stream. Canister samples were drawn for a subset of Hi-Flow measurements and were analyzed for gas species composition by a third-party lab using ASTM D-1945 compliant methods. Canister samples were taken for 249 of 460 Hi-Flow measurements to provide insight into typical gas compositions and provide a means for correcting Hi-Flow sensor response variation due to gas composition changes from calibration gas. Multiple samples were not drawn for measurements with a common (or similar) source or if the gas composition did not change at the facility. Instead, the first sample drawn was considered representative. For example, multiple emissions on a common gas feed would use the same gas composition sample for correction. Multiple samples were taken when the gas composition was expected to differ significantly. For example, an emission on a wellhead and a tank would require two samples.

Figure A1: *Direct, onsite measurements were performed with a Bacharach Hi-Flow sampler that was specially modified to allow canister samples to be drawn from its inlet.*

Downwind measurements were made using OTM33A or dual tracer flux methods with the CSU mobile laboratory. The mobile laboratory was equipped with a 3-D sonic anemometer, GPS, laser range finder, Aerodyne Research Inc QC-TLDS, Picarro G-2210i, and Licor 850 trace gas analyzers.

Figure A2: *The CSU mobile laboratory was used to make downwind measurements using both OTM33A and dual tracer flux methods. The lab is equipped with trace-gas analyzers targeting methane, nitrous oxide, acetylene, carbon dioxide, and water vapor, and supporting instrumentation to collect weather and positioning data.*

Onsite, Direct Measurements

Field measurements were made using a Bacharach Hi-Flow Sampler (Hi-Flow) which was specially modified for canister sampling. The Hi-Flow is currently the only known (commercially available) instrument for making total capture, direct emission rate quantifications of identified emission sources. The device draws in the total emission being sampled entrained in high volume of air and measures the total flow and the gas concentration. An emission rate is calculated from these measurements. The device is typically calibrated on methane at both low (2.5% CH_4 by volume) and high (99.99% CH_4 by volume) concentrations. The Hi-Flow does not measure methane directly; it measures whole gas response relative to the calibration gas and is sensitive to other hydrocarbon species. Therefore, corrections needed to be made to individual measurements based on the specific gas composition encountered during that measurement. Hi-Flow measurement parameters were recorded for each measurement including nominal flow setpoint (25%, 50%, 75%, or 100%), “Flow LPM”, “Leak %” and “Leak LPM”. The gas sensor within the Hi-Flow operates in one of two modes: catalytic oxidation (CatOx) or thermal conductivity (TCD). The transition between these two modes happens when the Leak % reaches 5% (nominally) but can vary slightly based on calibration and sensor condition.

The subset of measurements where lab samples were taken directly were compared to the Leak % reported by the Hi-Flow during measurement, as shown in Figure A3. The was done by computing a “Lab Canister Leak %” by partitioning the lab results into “whole gas” and “air” and calculating the whole gas percent of the mixture. “Air” was made of nitrogen, oxygen, and a proportional amount of carbon dioxide based on a 400-ppm atmospheric mixing ratio. The remaining carbon dioxide and hydrocarbon species were considered “whole gas” from the emission source and used to calculate a “Lab Canister Leak %.”

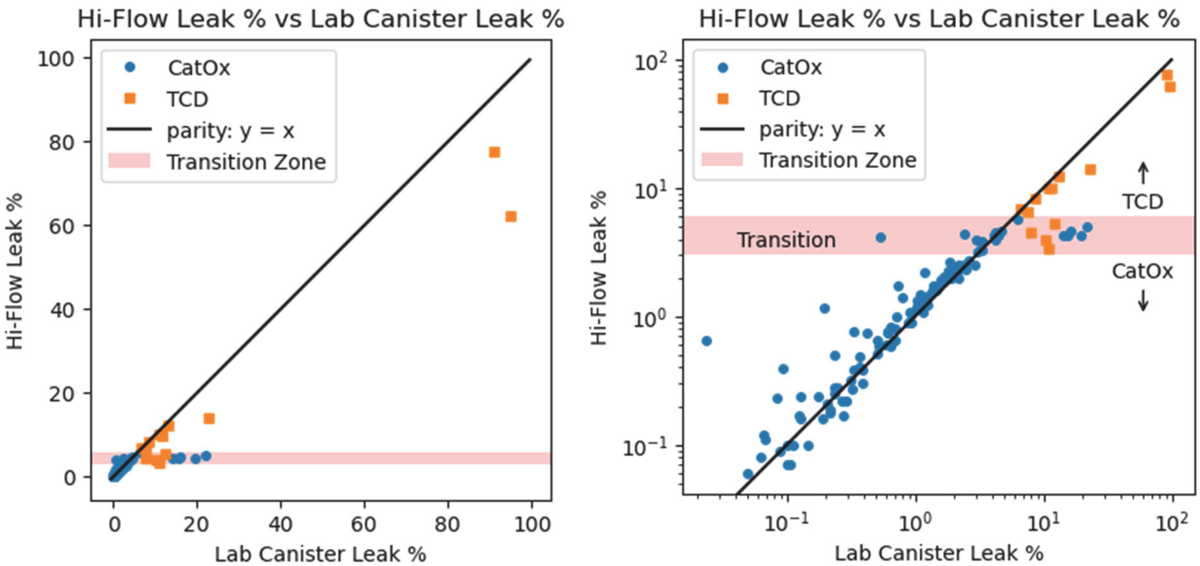


Figure A3: *Hi-Flow indicated leak % vs calculated lab canister leak % results. Linear scale plot on left, log-log scale plot on right. The high flow overpredicted leak % relative to lab results for lower concentrations (CatOx mode) and under predicted leak % relative to lab results at higher concentrations (TCD mode). No clear relation was evident in the transition zone between the two modes.*

Results shown in Figure A3 indicate that Hi-Flow and canister results follow similar trends but disagree at both low and high concentrations. This comparison also illustrates that no clear relationship can be established in the "transition zone", defined here as Hi-Flow indicated "Leak %" between 3 % and 6 %. As a first step in understanding this apparent discrepancy, gas speciation from lab canister analyses were used to compute expected relative responses of the instrument in both CatOx and TCD modes based on sensor response characteristics reported in data sheets. These did not improve agreement between Lab Canister Leak % and Hi-Flow Leak % substantially, and only changed Hi-Flow Leak % values slightly. This suggests that some other factor (or, more likely, combination of factors) influence the Leak % results reported by the Hi-Flow. Transition mode points were not considered during these comparisons.

Next, Hi-Flow Leak % and Lab Canister Leak % were compared considering the inaccuracies in each measurement method. The Hi-Flow manual states that the overall reported leak rate uncertainty is +/- 10 % of the reported value, the flow measurement is +/- 5 % of the reported value and the gas concentration measurement is the greater of 0.02 % or 5 % of the measured value. Tests in our own laboratory indicate that the flow measurements were +/- 5-6 % of the reported value using a calibrated laminar flow element. The uncertainty for Lab Canister Leak % uncertainty was calculated by propagating repeatability limits indicated for each species measurement in each sample through the calculation used to derive the Lab Canister Leak %. For the sake of comparison both Hi-Flow and lab were considered a 95% (1.96 sigma) uncertainty. The results were compared using a variance-weighted, least-squares (VWLS) regression for each mode, as shown in Figure A4. This comparison considers the uncertainty in each method, for each data point. Further, a bootstrap of the VWLS fit was performed by randomly varying the values of each point in accordance with its individual uncertainty and then re-performing the VWLS fit 1000 times. This provides a confidence interval on the fit and indicates the likelihood of bias at a given confidence level.

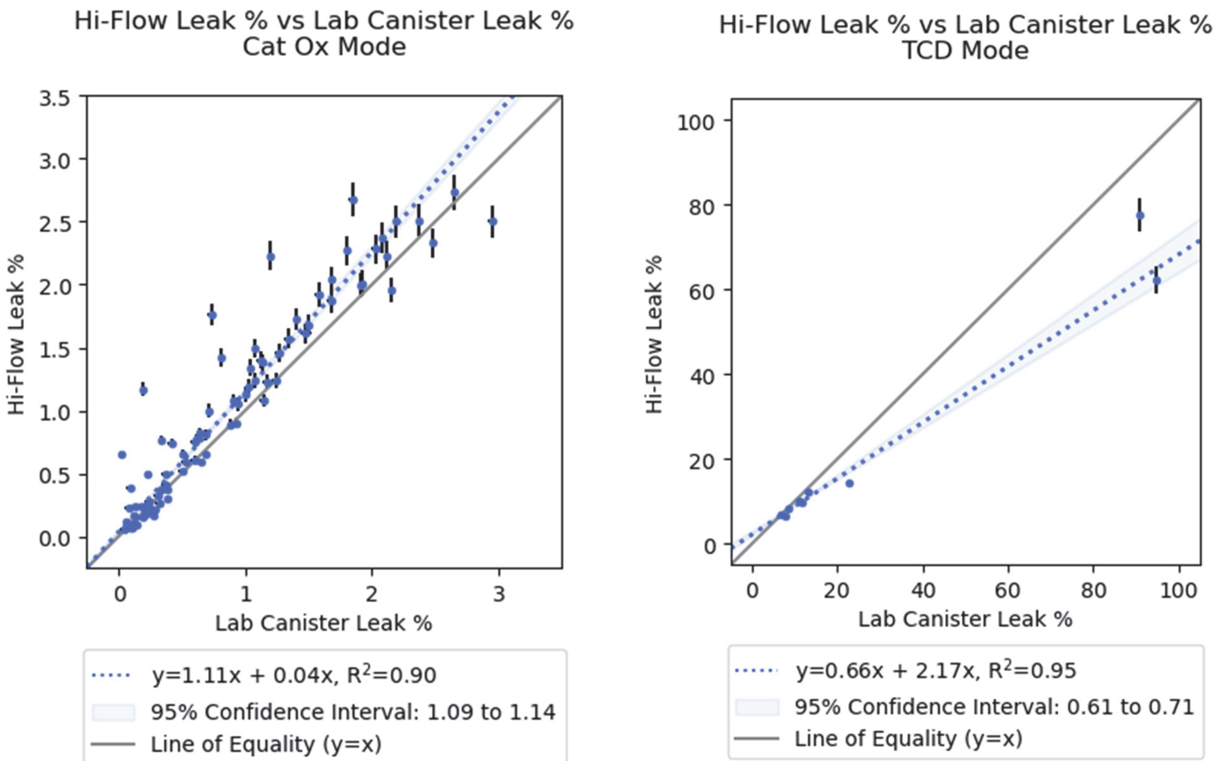


Figure A4: *VWLS regressions for Hi-Flow Leak % vs Lab Canister Leak % in both CatOx (left) and TCD (right) modes. Results indicate a bias in each of the modes. In CatOx mode, Hi-Flow Leak % is 11% high, in aggregate, relative Lab Canister Leak % results. In TCD mode, Hi-Flow Leak % is 44% low, in aggregate, relative Lab Canister Leak % results.*

For CatOx mode, the VWLS comparison indicated that Hi-Flow Leak % reported values were biased 11% high relative to Lab Canister Leak % results. The parity line was not included in the 95% confidence interval range of the bootstrap fits, indicating that the results are likely biased. An analogous procedure was performed for TCD mode measurements which indicate that Hi-Flow TCD measurements were biased 44% low relative to lab results. The confidence interval on the VWLS fit also did not include the parity line indicating that the results are biased 44% low at the 95% confidence level.

To correct for errors introduced by sampling gas composition differing from calibration, and establish an uncertainty estimate for each individual measurement (specific to the dataset acquired in this study), the following approach was used. First, to account for the bias relative to the Lab Canister Leak % results, all CatOx and TCD Leak % measurements were transformed using the VWLS best-fit equation to bring them into parity with Lab Canister Leak % results. Next, an empirical uncertainty was derived for each Hi-Flow measurement emission rate in a Monte Carlo model which considered the residuals from the VWLS fit (specific for each mode), the sensor uncertainty, and the flow uncertainty. For each measurement 10,000 Monte Carlo iterations were performed to provide a range of possible results for each measurement and provide a central, lower, and upper estimate. In each iteration of the model, Hi-Flow measurements falling in the transition zone were discarded and then randomly assigned a value from Lab Canister Leak % observations within the transition zone.

Most Hi-Flow measurements of a single emission source were replicated twice, each at a different Flow LPM. However, some measurements had only one replicate and some had several. For some emission points, several individual Hi-Flow measurements needed to be summed to quantify the emission entirely. Bias-corrected individual measurements (with uncertainty from the Monte Carlo model) were combined (replicates averaged and/or summed) using appropriate logic and quadrature rules for the individual case to result in a final emission rate with uncertainty.

Downwind Measurements

Downwind measurements were made using both OTM33A and dual tracer flux methods. OTM33A was used for all but one downwind measurement, which employed dual tracer flux. Tracer flux application was limited by the availability of downwind roads transecting plumes, and often the presence of closely grouped, confounding sources. Additionally, OTM33A measurements can be performed in a shorter time (20 minutes to 1 hour) compared to dual tracer flux (2-3 hours) which aligned well with the goal of maximizing the number of facilities screened each day. OTM33A measurements were offsite, onsite, or on site-access roads not suitable for transecting emission plumes from the facility. The fact that OTM33A measurements are made while the vehicle is stationary makes measurements from adjacent open terrain possible, where transects would not be feasible. Most OTM33A measurements made were of a single sources or closely spaced group of sources which had previously been identified during an OGI survey and could be isolated from other sources and quantified directly. Both measurement techniques proved useful when the presence of hydrogen sulfide (H_2S) gas eliminated the possibility of direct measurement.

Forty-one OTM33A measurements were made, with emission rates ranging from 0.02 to 368 SLPM. Downwind measurement distances were most typically between 30 m and 60 m but ranged between 12 and 250 m. Distances were measured with a laser rangefinder (Nikon ProStaff 3i) at the time of measurements and confirmed using satellite imagery (Google Earth) during data processing. Measurement periods were typically 20 minutes in length. Time-aligned ethane concentration data (Aerodyne QC or Picarro G-2210i) TLDAS instantaneous (1 Hz) wind speed and direction (Gill Windmaster or Gill Windsonic) were combined using software based on the EPA OTM33A method as published[1]. Wind bin sizes were varied between 6 and 30 degrees for each measurement to account for variation in wind speed, direction, and downwind distance in varying atmospheric stability classes. This effort was performed manually to minimize residuals to Gaussian fits and ensure that binned data points followed a Gaussian profile, as shown in Figure A5. Each OTM33A measurement was assigned an uncertainty of (+/- 30 %) of the measured value based on tests of the method against known releases in previous work [2–4].

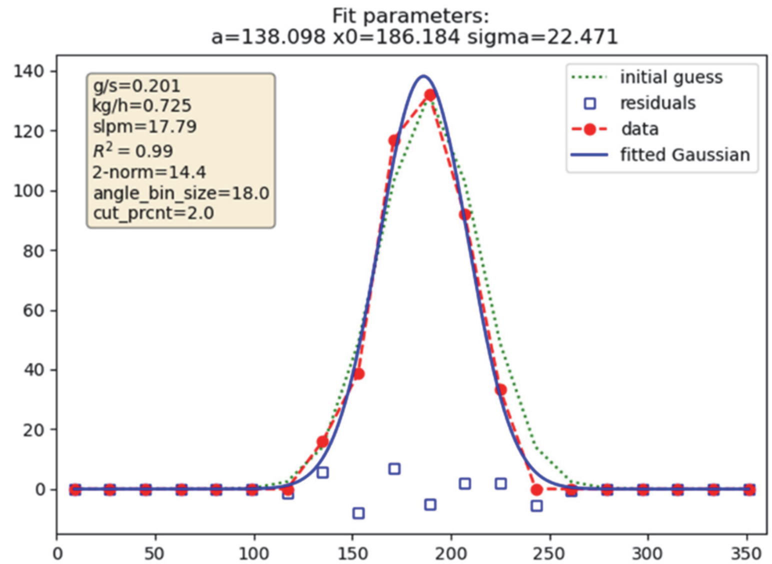


Figure A5: *Example OTM33A measurement computation output. Wind bin sizes were varied to identify a best fit.*

One dual tracer flux measurement was made during the field campaign. This measurement was of a tank battery with high H_2S content. The measurement was ideally sited with unimpeded downwind access and an absence of upwind or nearby confounding sources. Ten dual correlation plumes were accepted after passing QA/QC criteria outlined in Roscioli et al.[5] Measurement uncertainty for this source is reported as a 95% confidence interval about the mean based on a bootstrap mean performed on the emission rate calculated for each of the ten individual plumes.

1. US EPA ORD. OTM 33 Geospatial Measurement of Air Pollution, Remote Emissions Quantification (GMAP-REQ) and OTM33A Geospatial Measurement of Air Pollution-Remote Emissions Quantification-Direct Assessment (GMAP-REQ-DA) https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=309632 (accessed 2019 -06 -21).
2. Brantley, H. L.; Thoma, E. D.; Squier, W. C.; Guven, B. B.; Lyon, D. Assessment of Methane Emissions from Oil and Gas Production Pads Using Mobile Measurements. Environ. Sci. Technol. 2014, 48 (24), 14508–14515. https://doi.org/10.1021/es503070q.
3. Robertson, A. M.; Edie, R.; Snare, D.; Soltis, J.; Field, R. A.; Burkhart, M. D.; Bell, C. S.; Zimmerle, D.; Murphy, S. M. Variation in Methane Emission Rates from Well Pads in Four Oil and Gas Basins with Contrasting Production Volumes and Compositions. Environ. Sci. Technol. 2017, 51 (15), 8832–8840. https://doi.org/10.1021/acs.est.7b00571.
4. Edie, R.; Robertson, A. M.; Field, R. A.; Soltis, J.; Snare, D. A.; Zimmerle, D.; Bell, C. S.; Vaughn, T. L.; Murphy, S. M. Constraining the Accuracy of Flux Estimates Using OTM 33A. Atmospheric Meas. Tech. 2020, 13 (1), 341–353. https://doi.org/10.5194/amt-13-341-2020.
5. Roscioli, J. R.; Yacovitch, T. I.; Floerchinger, C.; Mitchell, A. L.; Tkacik, D. S.; Subramanian, R.; Martinez, D. M.; Vaughn, T. L.; Williams, L.; Zimmerle, D.; Robinson, A. L.; Herndon, S. C.; Marchese, A. J. Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Methods. Atmos Meas Tech 2015, 8 (5), 2017–2035. https://doi.org/10.5194/amt-8-2017-2015.

APPENDIX B

Statistical Exploratory Data Analyses

APPENDIX B
Statistical Exploratory Data Analyses

Exploratory data analyses were performed identify and assess the significance of possible correlations among:

i) Key metadata associated with various site, equipment, and operational conditions documented in the study field campaigns, such as well/site age, production rate, main product type, equipment count, region, and operator).

ii) The frequency of detected emissions among visited sites and observed equipment.

iii) The magnitude of qualified methane and/or whole gas emissions measurements.

All data variables were evaluated as either numeric values or categorical variables. A Spearman's Rank Correlation was used to assess correlations between numeric variables, and a Chi-Squared Test or a Fisher Test (depending on the sample size of the compared dataset) was used to assess the independence of categorical variables. In each case, a p-value 1% was used to reject the null hypothesis that any two compared variables are independent. In other words, any test with a p-value less than or equal to 1% indicates the compared variables are not independent.

Factors specific to major equipment types or components were investigated to identify any significant correlation to emission detection frequency or measured methane or whole gas emission rates. Emission rates were observed and compared based on their causes, identifying where the emitting components warranted repair or if operational conditions or practices warranting improvement.

CORRELATION ANALYSIS METHODS

Categorical Variables

Depending on sample size, a Chi-Squared Test or a Fisher was used to assess correlations between key categorical variables and i) the frequency of detected emissions and ii) the magnitude of measured emissions. Where possible, a Chi-Squared Test was used to determine if two categorical variables were independent; however, if the sample size was too small (expected frequency less than 5%) a Fisher Test was used. For purposes of these analysis, emissions frequency and magnitude (as numerical variables) were converted to categorical variables as follows:

- Low - value <= 25th Percentile
- Medium - value > 25th Percentile and value < 75th Percentile
- High - value >= 75th Percentile

Categorical variables were similarly established for sitewide equipment counts (a proxy for "site size") and sitewide (total) oil and gas production rates using the following bins based on the observed numeric distributions of these variables:

- Small = 1 piece of equipment
- Medium = 2-3 pieces of equipment

- Large = 4-5 pieces of equipment
- X-Large = 5+ pieces of equipment
- boe_0 = 0 boe/day
- boe_0-1 = 0-1 boe/day
- boe_2-4 = 2-4 boe/day
- boe_4-8 = 4-8 boe/day
- boe_8-16 = 8-16 boe/day
- boe_32-64 = 32-64 boe/day
- boe_64-128 = 64-128 boe/day
- boe_>128 = 128+ boe/day

In the tables below, a p-value of less than or equal to 1% for both the Chi-Squared and Fisher tests was used to reject the null hypothesis that the compared variables are independent. Related test statistics are also shown for the Chi-Squared tests, where the primary test statistic is reflective of the sample size, and the adjusted statistic (contingency coefficient) is normalized to range from 0 to 1 independent of sample size. These adjusted test statistics can be used as a relative indicator of the strength of association between compared variables; however, they do not indicate or account for positive vs. negative association. For interpretation, the relative strength of association among variables compared using a Chi-Squared test was considered based on the following scale:

- Weak: Chi-Squared adjusted statistic between 0.0 – 0.39
- Moderate: Chi-Squared adjusted statistic between 0.40 – 0.59
- Strong: Chi-Squared adjusted statistic between 0.6 – 1.0

Numeric Variables

A Spearman's Rank Correlation was used to assess correlations between key numeric variables and specific numeric values quantifying i) the frequency of detected emissions and ii) the magnitude of measured emission for each site or type of evaluated equipment. Spearman's Rank Correlation is a non-parametric method used to test the hypothesis of no association between population datasets and indicates if any significant monotonic relationship (either increasing or decreasing) exists between the compared variables. The Spearman rank order coefficient (rho) falls between -1 (perfectly negative correlation) and +1 (perfectly positive correlation). In the tables below, a p-value of less than or equal to 1% for the Spearman's Rank Correlation indicates the compared variables are associated. For interpretation, the relative strength of association among variables compared using a Spearman's Rank Correlation was considered based on the following scale:

- Weak: Spearman *rho* between +/- 0.0 – 0.39
- Moderate: Spearman *rho* between +/- 0.40 – 0.59
- Strong: Spearman rho between +/- 0.6 – 1.0

SITEWIDE EMISSIONS ANALYSIS

Exploratory analyses of sitewide emissions separately considered the detection of one or more emissions at any type of equipment, the frequency of emissions expressed as the number of detected emissions divided by the total pieces of equipment at a site, and the total magnitude of methane and whole gas emissions at all sites where 100% of detected emissions were successfully quantified.

Variables included in the exploratory analysis of sitewide emissions were:

- Primary product – gas or oil
- Gas production rate, boe/d
- Oil production rate, boe/d
- Total O&G production, boe/d
- Total O&G production (categorical)
- Major equipment count (numeric)
- Major equipment count/Site "size" (categorical, e.g., small, medium, large)
- Gas production frequency
- Oil production frequency
- Routine emissions monitoring frequency
- Host operator
- Basin
- Eastern or Western US
- Age of the well or site

Table B.1 summarizes the site variables on which sitewide emissions frequency and/or magnitude were determined to be dependent. Site emission frequency is most strongly correlated to major equipment count, especially as a categorical variable (described above) and moderately positive with the numeric value. Site equipment count also exhibited the strongest associations among evaluated numerical variables with both frequency and magnitude of emissions, yet with only a moderate positive correlation with detection frequency and weak associations with whole gas and methane emission rates. Weak correlations were also consistently detected among both the frequency and magnitude of emissions, total oil and gas production, and gas production rates.

Weak associations were also noted with either detection frequency or magnitude and host operator or region; however, no such associations were noted consistently with both frequency and magnitude, as were major equipment counts and total oil and gas production. Moreover, any apparent association with host operator could be due to the large range in the number of sites visited with each operator, ranging from 3 (including, 100% of one operator's wells) to over 100 across several of the regions. This was not further evaluated due to the strength of other more likely significant correlations.

***Table B.1** Summary of Site Variables Associated with Sitewide Emissions Detection Frequency and Magnitude*

Variable-Y	Test(s)	Chi/Fisher p-Value	Adjusted Statistic	Spearman p-Value	Spearman *rho*	Est. Association
Frequency of Detected Emissions						
Gas production rate	Spearman	-	-	8.06e-03	0.112	weak
Total O&G production	Fisher, Spearman	1.00e-03	-	1.09e-04	0.163	weak
Basin	Chi-Squared	2.91e-13	0.414	-	-	moderate
Eastern or Western US	Chi-Squared	8.94e-05	0.248	-	-	weak
Emissions monitoring frequency	Fisher	5.00e-04	-	-	-	-
Major equipment count	Chi-Squared, Spearman	1.38e-46	0.648	2.14e-27	0.42600	strong (cat.), moderate (num.)
Whole Gas Emission Rate – Sitewide Average						
Host Operator	Fisher	0.0040	-	-	-	-
Basin	Fisher	0.0030	-	-	-	-
Methane Emission Rate – Sitewide Average						
Host Operator	Fisher	0.0025	-	-	-	-
Basin	Fisher	0.0030	-	-	-	-
Well Age	Spearman	-	-	5.95e-03	0.2930	weak
Whole Gas Emission Rate – Sitewide Total						
Host Operator	Fisher	0.0005	-	-	-	-
Major equipment count	Fisher, Spearman	0.0005	-	8.43e-09	**0.3900**	weak
Gas production rate	Spearman	-	-	3.83e-04	0.2530	weak
Total O&G production	Spearman	-	-	9.85e-03	0.1850	weak
Methane Emission Rate – Sitewide Total						
Host Operator	Fisher	0.01000	-	-	-	-
Eastern or Western US	Chi-Squared	0.00544	0.312	-	-	weak
Major equipment count	Fisher, Spearman	0.00100	-	8.28e-07	0.3370	weak
Gas production rate	Spearman	-	-	1.29e-03	0.2300	weak
Total O&G production	Spearman	-	-	5.54e-04	0.2460	weak

EQUIPMENT EMISSIONS ANALYSIS

Exploratory analyses of equipment-specific emissions focused exclusively on the three most frequently encountered, most frequently emitting, and largest emitting types of equipment: tanks, separators, and wellheads. Factors considered for all three types of equipment type included host operator, site production status (active, inactive, shut-in, etc.), basin/region, primary product, oil and gas production rates, and production frequency. Other factors were specific to the equipment characteristics. Tank emissions were evaluated against the quantity of hatches and vents, whether tank vents were atmospheric or pressurized, the fluid level of the tank while onsite (fullness). Wellhead emissions were evaluated against variables such as the presence of casing vents, well age, well depth (where pressure of the production formation could relate to casing head pressure), artificial lift type, and whether the well was producing brine. Separator emissions were evaluated against variables such as separator age, the number of phases it was designed to separate, maximum design pressure, and operational pressure.

Equipment were first evaluated against all available data to explore factors relating to whether an emission was either detected or not detected at a piece of equipment, then variables associated with the occurrence of detections were further analyzed relative to the frequency of and magnitude of emissions among the respective equipment types. Table B.2 displays the variables which were determined to be dependent based on tests based on equipment type. Key findings of the equipment-specific exploratory analysis are as follows:

- ***Separator emissions:*** Emission detection frequency appears to be strongly associated with the number of phases (2 or 3) of the separator and site production rates, corresponding to throughput. Maximum design pressures exhibited a strong statistical association with emission detections, however operational pressure had a moderate association. Although the adjusted Chi-Squared statistic indicates even stronger correlation the site basin, this is most likely due to the prevalence and near uniqueness of encountering only 3-phase vs. 2-phase separators in some of the basis.
- ***Wellhead emissions:*** Only weak associations were apparent between emission detection frequency and evaluated wellhead characteristics. The strongest of these were with host operator, basin, well depth (potentially a proxy for wellhead casing pressure), and gas production rate.
- ***Tank emissions:*** Only weak associations were found between emission detection frequency and evaluated tank characteristics. The strongest of these were with the presence of pressurized or atmospheric vents, oil production rate, and liquid level.

Table B.2: *Correlations determined through Fisher and Chi-Squared tests for equipment types.*

Variable-Y	Test(s)	P-Value	Adjusted Statistic
Separator Emissions Detection			
Host Operator	Fisher	5.00e-04	-
Basin	Chi-Squared	3.63e-53	0.749
Eastern or Western US	Chi-Squared	5.28e-16	0.434
Monitoring Frequency	Fisher	5.00e-04	-
Active/Inactive	Chi-Squared	9.84e-04	0.216
Primary Product	Chi-Squared	9.02e-13	0.387
Frequency of Oil Production	Chi-Squared	7.49e-04	0.231
Average Oil Production Rate	Chi-Squared	1.04e-13	0.44
Average Gas Production Rate	Chi-Squared	1.05e-13	0.439
Sitewide Production Rate	Chi-Squared	9.36e-12	0.408
Max Pressure	Chi-Squared	1.71e-31	0.677
Operational Pressure	Chi-Squared	2.71e-14	0.504
Equipment Age	Chi-Squared	2.07e-03	0.22
Separator Phases	Chi-Squared	8.97e-15	0.432
Wellhead Emissions Detection			
Host Operator	Fisher	5.00e-04	-
Basin	Chi-Squared	8.39e-05	0.267
Well Age (Years)	Chi-Squared	6.42e-03	0.227
Well Depth (Ft)	Chi-Squared	7.07e-04	0.268
Monitoring Frequency	Fisher	7.00e-03	-
Average Gas Production Rate	Chi-Squared	1.13e-04	0.235
Sitewide Production Rate	Chi-Squared	8.36e-03	0.172

Variable-Y	Test(s)	P-Value	Adjusted Statistic
Tanks Emissions Detection			
Host Operator	Fisher	5.00e-04	-
Basin	Chi-Squared	2.47e-03	0.201
Oil Production Frequency	Chi-Squared	1.10e-03	0.197
Average Oil Production Rate	Chi-Squared	3.95e-07	0.275
Average Gas Production Rate	Chi-Squared	2.23e-03	0.179
Sitewide Production Rate	Chi-Squared	4.10e-04	0.202
Tank Fullness	Chi-Squared	6.32e-04	0.22
Primary Product	Chi-Squared	6.86e-04	0.173
Quantity of Hatches	Fisher	5.00e-04	-
Pressurized or Atmospheric Vents	Chi-Squared	1.52e-09	0.325

Table B.3: *Correlations determined through Fisher, Chi-Squared, and Spearman tests for equipment types.*

Variable	Test(s)	P-Value	Adjusted Statistic	Spearman P-Value	Spearman Rho
Magnitude of Whole Gas Emission Rate - Separators					
Host Operator	Fisher	0.0070	-	-	-
Basin	Fisher	0.0045	-	-	-
Monitoring Frequency	Fisher	0.0010	-	-	-
Magnitude of Methane Emission Rate - Separators					
Host Operator	Fisher	0.0005	-	-	-
Basin	Fisher	0.0015	-	-	-
Monitoring Frequency	Fisher	0.0020	-	-	-
Magnitude of VOC Emission Rate – Wellheads					
Well Depth	Spearman	-	-	0.00956	0.3820
Eastern or Western US	Chi-Squared	0.00142	0.54	-	-
Basin	Fisher	0.0025	-	-	-
Monitoring Frequency	Fisher	0.0035	-	-	-
Oil Vs. Gas	Fisher	0.0005	-	-	-
Magnitude of VOC Emission Rate – Separators					
Host Operator	Fisher	0.0005	-	-	-
Basin	Fisher	0.0005	-	-	-
Monitoring Frequency	Fisher	0.0005	-	-	-
Operational Pressure	Spearman	-	-	0.0086	-0.2050
Oil Vs. Gas	Fisher	0.0005	-	-	-
Magnitude of VOC Emission Rate – Tanks					
Host Operator	Fisher	0.0005	-	-	-
Basin	Fisher	0.0005	-	-	-
Oil Production	Spearman	-	-	0.00106	0.332
Sitewide BOE/d	Spearman	-	-	0.000056	0.399

Among evaluated numeric variables, site equipment count also exhibited the strongest associations with both frequency and magnitude of sitewide emissions, exhibiting only a moderate positive correlation with detection frequency and weak associations with whole gas and methane emission rates. Weak correlations were also consistently detected among both the frequency and magnitude of emissions, total oil and gas production, and gas production rates. Figures B1 through B4 illustrate that these correlations are apparent among the data for total sitewide emissions for both gas sites and oil sites, respectively.

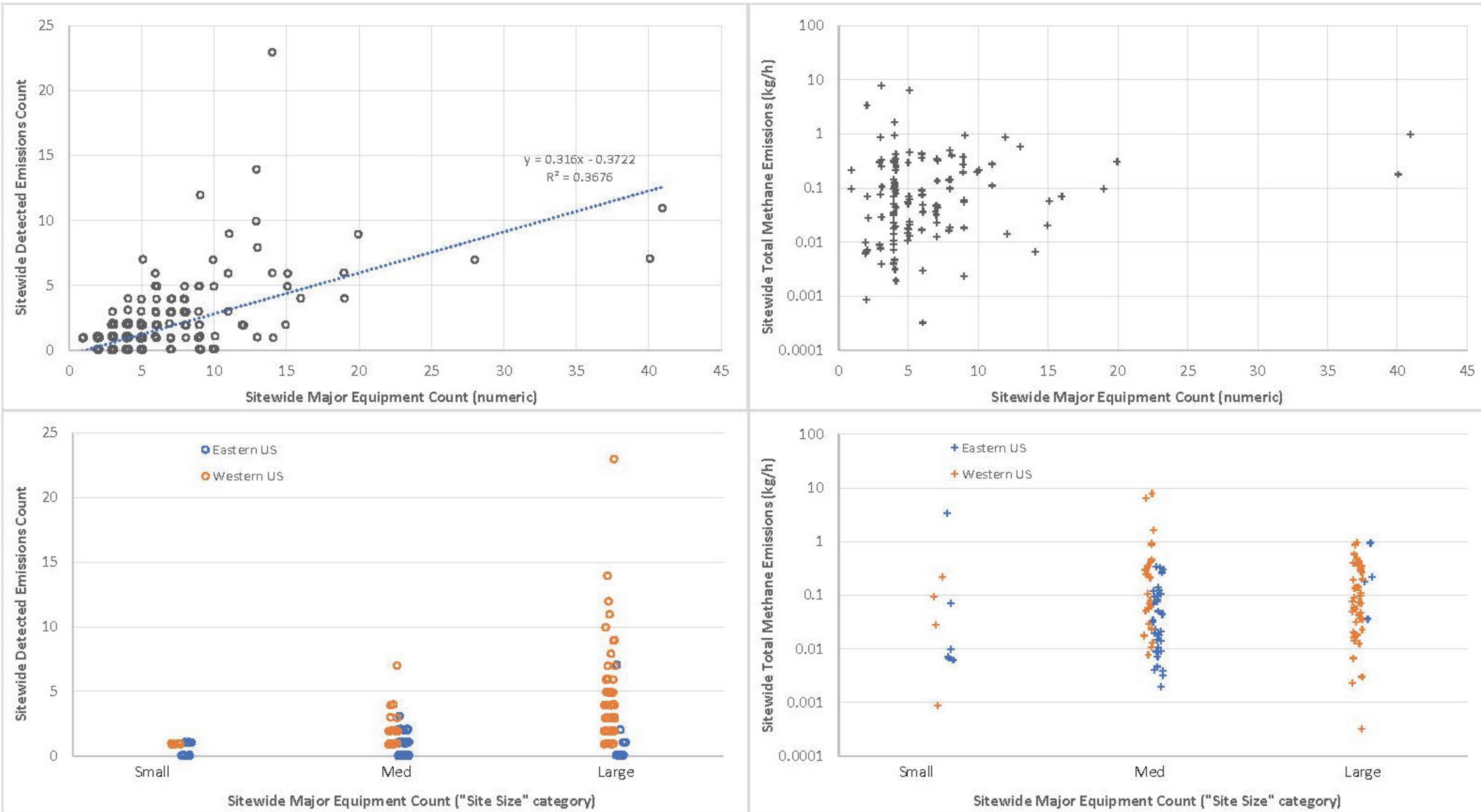


Figure B1. *Magnitude and frequency of methane emissions compared to equipment counts at natural gas sites.*

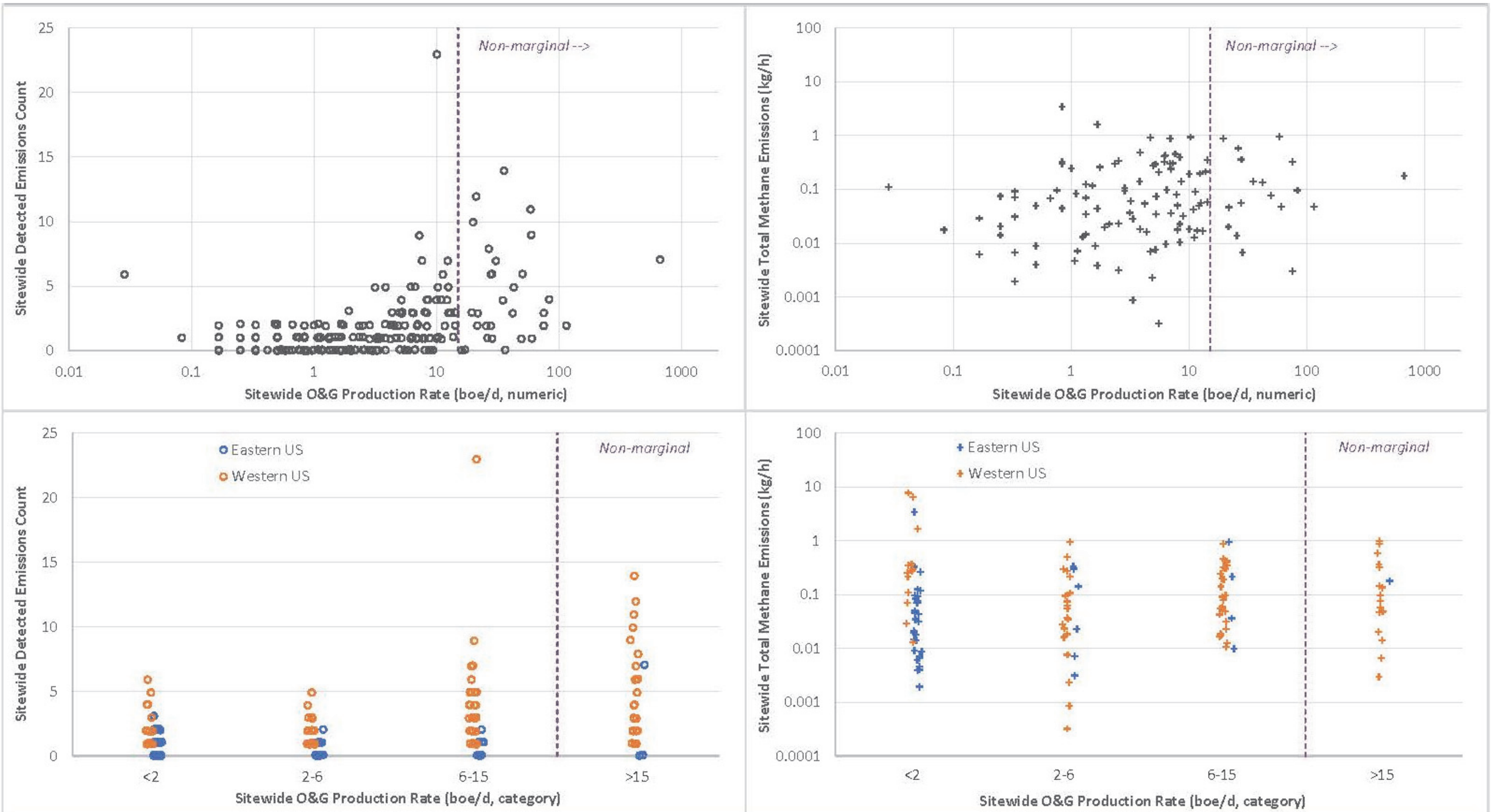


Figure B2. *Magnitude and frequency of methane emissions compared to production rates at natural gas sites.*

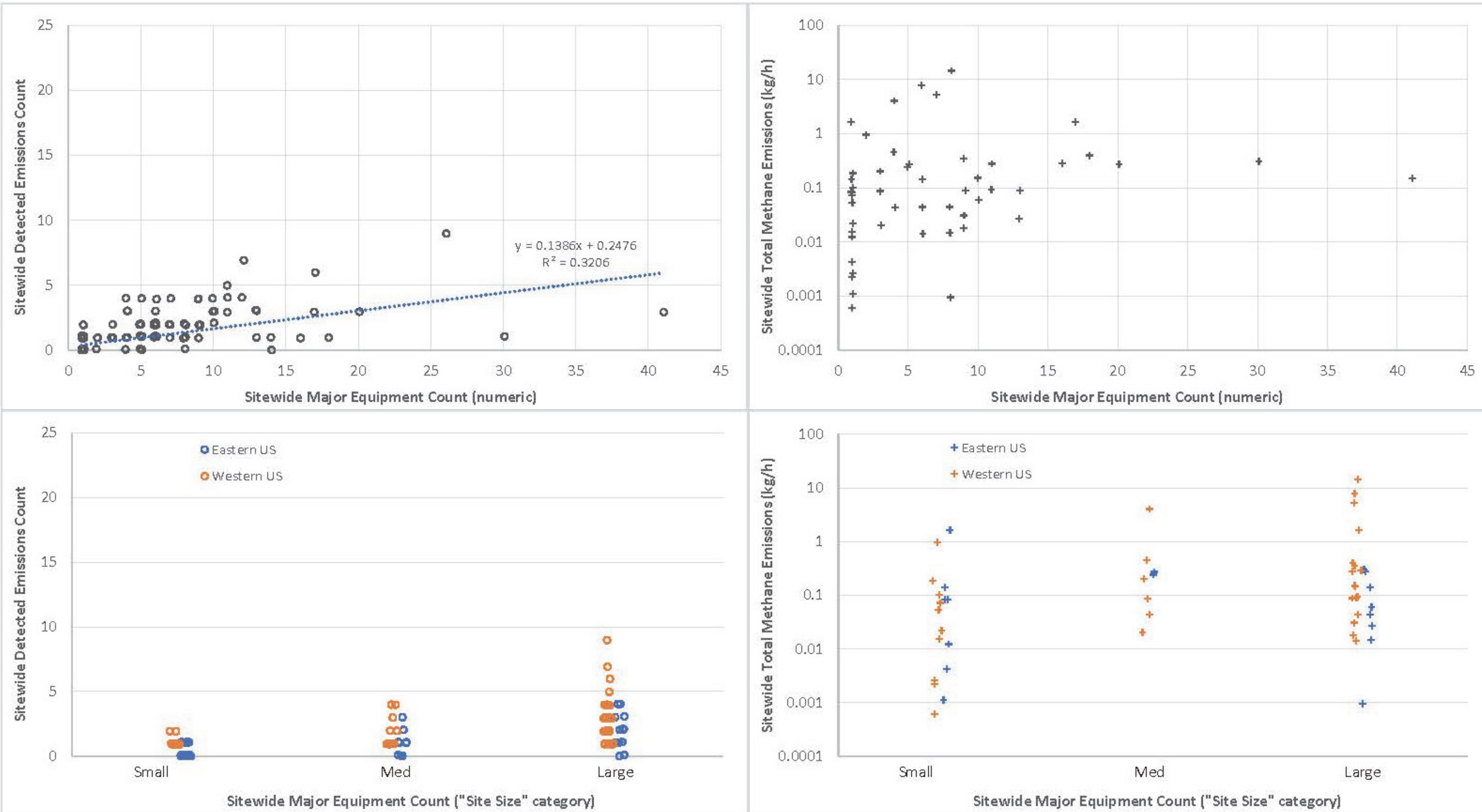


Figure B3. *Magnitude and frequency of methane emissions compared to equipment counts at oil sites.*

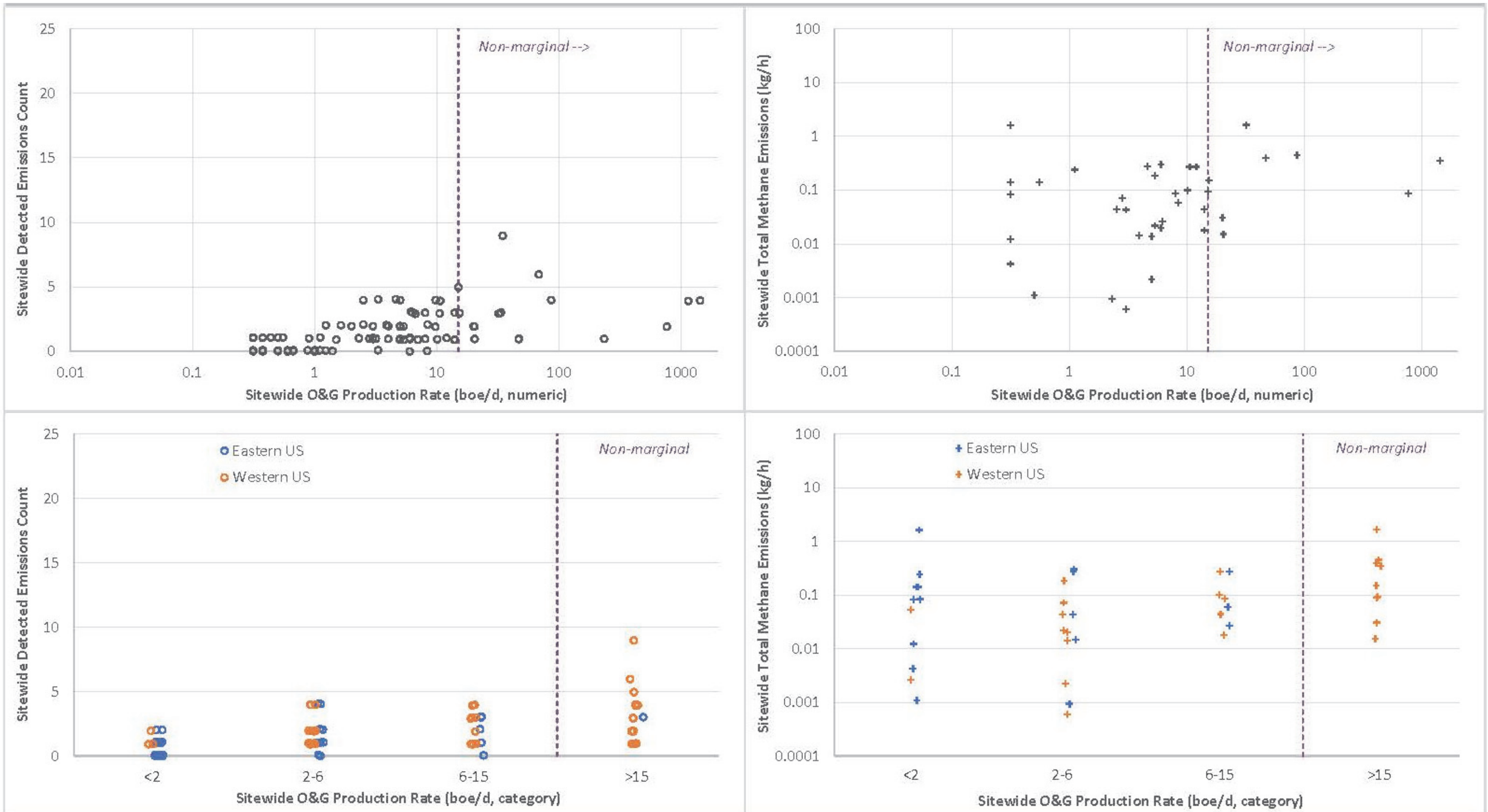


Figure B4. *Magnitude and frequency of methane emissions compared to production rates at oil sites.*