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RESEARCH ARTICLE

Gathering pipeline methane emissions in Fayetteville shale pipelines and scoping guidelines for future pipeline measurement campaigns

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Gathering pipelines, which transport gas from well pads to downstream processing, are a sector of the natural gas supply chain for which little measured methane emissions data are available. This study performed leak detection and measurement on 96 km of gathering pipeline and the associated 56 pigging facilities and 39 block valves. The study found one underground leak accounting for 83% (4.0 kg CH_4/hr) of total measured emissions. Methane emissions for the 4684 km of gathering pipeline in the study area were estimated at 402 kg CH_4/hr [95 to 1065 kg CH_4/hr, 95% CI], or 1% [0.2% to 2.6%] of all methane emissions measured during a prior aircraft study of the same area. Emissions estimated by this study fall within the uncertainty range of emissions estimated using emission factors from EPA's 2015 Greenhouse Inventory and study activity estimates. While EPA's current inventory is based upon emission factors from distribution mains measured in the 1990s, this study indicates that using emission factors from more recent distribution studies could significantly underestimate emissions from gathering pipelines. To guide broader studies of pipeline emissions, we also estimate the fraction of the pipeline length within a basin that must be measured to constrain uncertainty of pipeline emissions estimates to within 1% of total basin emissions. The study provides both substantial insight into the mix of emission sources and guidance for future gathering pipeline studies, but since measurements were made in a single basin, the results are not sufficiently representative to provide methane emission factors at the regional or national level.

Keywords: methane; natural gas; emissions; pipelines; greenhouse gas

Introduction

U.S. dry natural gas production increased from 18 to 27 trillion ft^3 between 2005 and 2015 (EIA, 2016b). Use of natural gas offers potential climate benefits compared to coal or oil (EIA, 2016a), but those benefits depend upon the emissions of methane, the primary component of natural gas and a potent greenhouse gas. This study is part of a larger study designed to compare, and possibly reconcile, estimates of methane emissions developed from aircraft "top-down" measurements (Schwietzke et al., 2017) and inventory-based "bottom up" estimates, including the results presented here and studies of production facilities (Bell et al., 2017), gathering compressor stations (Vaughn et al., 2017), and measurements made by downwind techniques (Robertson et al., 2017; Yacovitch et al., 2017) at a variety of facilities.

Gathering pipelines refer to the pipelines that connect wells to gathering compressor stations or processing plants, and connect those facilities to transmission pipelines or distribution systems. Inlet pressures of gathering systems range from 30 to 7,720 kPa (Mitchell et al., 2015), but most gathering pipelines operate at the low end of that pressure range. Gathering pipeline systems consist of pipelines and auxiliary components for operation of the pipelines including pig launchers and receivers, blocking valves, and a variety of other, less common, components (e.g. "knock out bottles" used to remove liquids from pipelines on older systems). Pig launchers/receivers are used to insert/remove cleaning plugs, called "pigs", into gathering lines to remove water and debris from the pipeline. Block valves are used to isolate sections of pipeline, or reroute the flow of natural gas (SM-S1).

Gathering pipeline network methane emissions originate from three sources:

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1) *Emissions from pipelines* between auxiliary equipment. Pipelines are typically underground, although some older systems utilize above-ground pipelines. Underlying causes of pipeline emissions include corrosion, failed joints, and structural stresses caused by settling earth or the traversal of heavy equipment. While many new pipelines are constructed of plastic material, most older gathering lines, as well as some recently-built pipelines, are constructed from steel, and are thus subject to corrosion as the pipeline ages. In addition, even for pipeline constructed of polyethylene, significant infrastructure is still constructed using steel pipe and equipment, such as above-ground auxiliary equipment, road crossings, and other higher-stress areas. These can also exhibit corrosion problems. Pipelines may also be damaged by accidental contact by outside parties.
2) *Emissions from auxiliary equipment*, such as emissions from valve packing, or seals on pig launcher doors. Auxiliary equipment is also called "above ground" equipment by operators.
3) *Episodic emission from pipeline operations*. Episodic emissions are releases of gas that occur for defined, typically short, periods. While gas may be released due to emergency situations arising from mishaps, the two most-common planned episodic emissions for gathering pipelines are the blowdown of lines for maintenance and the blowdown and purging of pig launchers and receivers during pigging operations.

This study measured the first two types of emissions – underground pipelines and auxiliary equipment – and performed an engineering estimation of planned episodic emissions.

The authors are unaware of any recently published studies of gathering pipeline emissions, and as a result, emission factors are unknown for this sector (Heath et al., 2015). EPA's greenhouse gas inventory (GHGI) uses emission factors based upon measurements of distribution mains from a 1996 GRI/EPA study (GRI/EPA, 1996) to approximate emissions for gathering pipelines. The majority of gathering pipelines are not regulated by the U. S. Pipeline and Hazardous Material Administration because they do not cross state boundaries and are in rural areas that fall below population proximity rules (Pipeline and Hazardous Materials Safety Administration, 2016). Recent studies have characterized emissions for gathering and processing plants (Mitchell et al., 2015) and well pads (Allen et al., 2013; Allen, et al., 2015a; Allen, et al., 2015b), but none of these studies performed measurements on gathering pipelines. Several recent studies have evaluated regional methane emissions using aircraft measurements (Beck et al., 2012; Karion et al., 2015; Peischl et al., 2015), but the methods utilized did not support attribution to specific portions of the gathering infrastructure. Other ground-based leak detection campaigns focused on another type of natural gas pipeline: distribution systems (Phillips et al., 2013; Jackson et al., 2014; Gallagher et al., 2015); this study makes specific comparisons to measurements of distribution mains from a study by Lamb et al. that included most distribution infrastructure between the city gate and the consumer's meter (Lamb et al., 2015). However, distribution pipelines carry dry market gas to customers and thus operate differently than gathering pipelines carrying raw production gas between wells and processing or compression facilities. In summary, since no recent study has systematically measured methane emissions from gathering pipelines, estimates have been based upon aggregate emission factors from distribution pipeline measurements.

Although limited to one basin, this study represents a first attempt to characterize gathering pipeline methane emissions. While the data are not sufficiently representative to provide methane emission factors at the regional or national level, the study provides initial information about the mix of emission sources and guidance to design future gathering pipeline studies.

Methods

Measurement campaign

The field campaign for this study occurred during a coordinated 4-week campaign in the Fayetteville shale play in Arkansas, USA during September–October 2015 (SM-S2). Measured pipelines, along with wells and compressor stations in the campaign area, are shown in **Figure 1**. There were approximately 5,650 active wells in the study area, which produced approximately 2.5 billion cubic feet per day (bcfd) at the time of the study (Arkansas Oil and Gas Commission, 2015). All active wells and the associated pipelines in the study area were completed after 2004, and 79% of all active wells went online after 2008 (AOGC, 2016). Natural gas produced in the study area is "sweet and dry" (90–98% methane, 0.5–6% ethane), produces no natural gas liquids, and requires minimal upgrading (i.e. no NGL extraction) to achieve pipeline quality. Water is separated from the gas at the well pads utilizing gravity-type separators, and gas is further dehydrated at the gathering compressor station using glycol dehydrators. The pipelines measured for this study were operated by two study partners. For their systems, the suction side of the gathering compressors operates between 100 and 325 kPa (15–50 psia). Due to the low suction pressures, gathering pipelines between wells and gathering compressor stations are larger in diameter than many basins – typically 4 to 20 inches (10 to 51 cm) in diameter. Underground segments are constructed largely of polyethylene (commonly known as "poly" pipe), coupled to steel segments for above-ground infrastructure. Pipelines from other operators, which were not measured in this study, vary in configuration, with at least one partner company operating their well-to-compressor pipelines at 1–2.8 MPa (150–400 psia), using smaller diameter steel lines. Considering the entire study area, 69% of well-to-compressor gathering pipelines are plastic, and all measurements were made on this type of pipeline. Lines between compressor stations and transmission pipelines in the study area, which were not measured in this study, are constructed of steel and operate between 6 and 8 MPa (850–1150 psia).

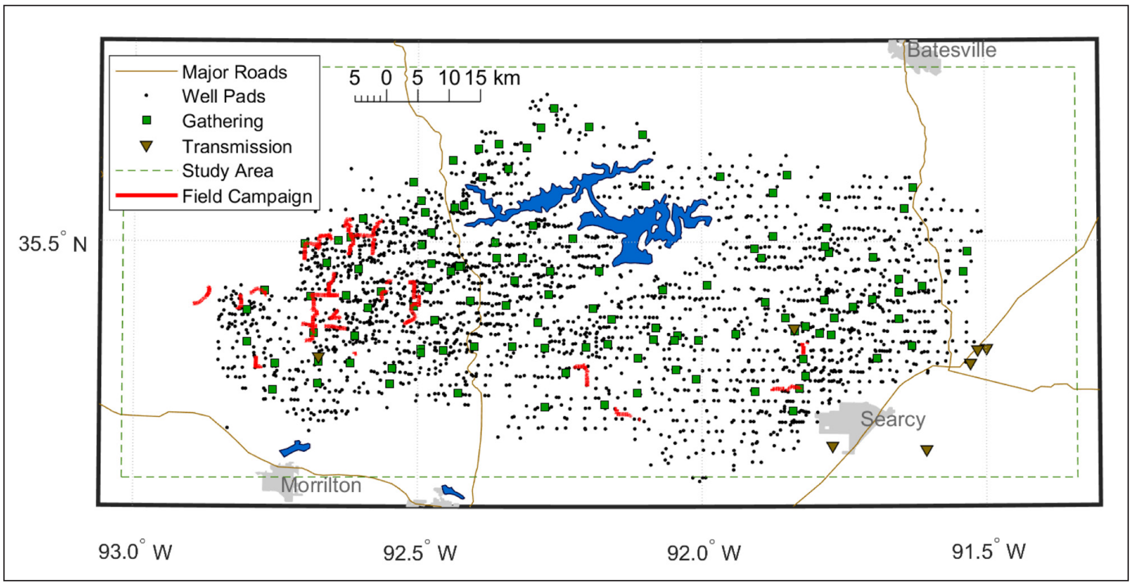

Figure 1: Study area. The 2430 well pads – which host approximately 5,650 active wells – are shown, along with 125 known gathering and 7 transmission compressor stations in the study area. The 96 km of pipeline measured during 12 measurement days are highlighted in red. The study area was defined by aircraft mass balance measurements made during the campaign, and is approximately 65 × 180 km. DOI: https://doi.org/10.1525/elementa.258.f1

Gathering pipelines are installed in rights of way (ROW), defined by an easement allowing the operator to access and maintain their pipelines. A ROW segment may contain more than one pipeline, but all ROWs measured in this study contain a single pipeline from a single operator. Partner personnel inspect pipelines at irregular intervals by driving or walking the ROWs. In general, these inspections concentrate on identifying encroachment or damage, and teams do not routinely measure leak volume or mass flow from leaks when found. Teams from one partner may carry a laser gas detector to look for leaks (e.g. a Heath, Inc. RMLD). This partner also does occasional flyovers to look for encroachment and distressed vegetation, a possible sign of a gas leak. The other partner does regular leak surveys only on regulated lines (a small fraction of the total). For non-regulated lines, they walk lines and conduct vegetation control biennially, and during these activities they assess for visible indications of leaks.

The study partners who supported measurement on their pipeline systems operated an estimated 83% of gathering pipelines in the study area at the time of the field campaign. However, measurement was not practical on all partner ROWs. ROWS were excluded for the following reasons: too steep to traverse with the measurement equipment, covered with un-harvested crops, access was restricted by the landowner, or the ROW was covered with vegetation growth too dense to traverse with the available screening equipment (SM-S2). One partner company cuts brush on ROWs every two years, and during the study period only the western half of the study area was sufficiently cleared for measurement. In general, both partners operated their pipelines in a similar fashion, and no differences in operation were identified due to season or location within the basin.

During the measurement campaign, measurement days were allocated to each operator in proportion to the number of wells they operate. Each measurement day, sections of accessible ROWs were selected for measurement. After specific ROWs to be measured were determined each day, the measurement team screened as much of the selected ROWs as possible. Measurements were made on 12 days, traveling an average of 8 km per day with a minimum of 4 km in a day and a maximum of 15 km per day.

Measurement teams screened and measured both pipeline leaks and emissions from auxiliary equipment along the pipeline. Underground pipeline leaks were detected by using a vehicle-based measurement system (VMS) that drove the ROWs looking for methane mixing ratios above background levels. Measurement vehicles were outfitted with a gas collection manifold on the front bumper of the vehicle routed to a Los Gatos Research Ultraportable Greenhouse Gas Analyzer, with a detection threshold of 0.01 ppm over ambient methane mixing ratio (SM-S3). Elevated emissions were further investigated using handheld equipment including a RMLD-IS laser gas detector and a Detecto PAK Infrared (DP-IR) probe-type detector, both from Heath Consultants, and a Bascom-Turner Gas Sentry instrument sensitive to methane mixing ratios from 100 ppm to 100% CH_4. One underground leak was detected and localized using these instruments (see below). The Heath instruments have a self-test feature used daily, but were not calibrated in the field. The Gas Sentry instrument was zeroed in clean air and bump tested daily (Bump Test of Gas Monitors, 2014). The Los Gatos instrument was calibrated daily using calibration gases as specified in the operations manual.

Measurement methods followed the methods utilized in a previous study of distribution systems (Lamb et al., 2015), which were developed for measurement of distribution pipeline leaks, and were supervised by the same scientists. In short, detected pipeline leaks were covered with an impermeable cover which enclosed the leak location and was held against the ground around its edge by weights. High flow methods were utilized to measure the leak rate: The emission gas and air were drawn from the enclosure and methane mixing ratio and total mass flow were measured. Methane mass flow from the leak was then calculated from mass flow and methane enhancements above the background mixing ratio. Measurements were made using an INDACO high flow instrument calibrated daily using zero air and span gas (2.5% CH_4 and 100% CH_4 in air) and checked at mid-day and the end of the day (see Lamb et al., 2015, SI S-3.1). The flow sensor was checked against an independent air flow meter (TSI VelociCheck 8340) at the beginning and end of each sampling event. Instruments are listed in SM-S3. In this study, only one pipeline leak was detected, and gas emissions occurred from a distinct hole in the ground several cm in diameter (an emission pattern called a 'gopher hole' by operational personnel) which was readily enclosed with an impermeable cover of approximately 1 m^2 (see Lamb et al., 2015, SI S-3.2). Since the gas in the study area is dry, there were few volatile organic compounds in the gas stream, and thus low risk of poisoning sensors or skewing the methane mixing ratios measured by the INDACO instrument. Uncertainty in the enclosure method, analyzed in SM-S3, is small relative to the uncertainty caused by frequency of the leak count, and was not included in simulation models.

While screening the ROWs, measurement vehicles would periodically arrive at auxiliary equipment (block valve and/or pig launcher) and measurement staff would survey the components with the INDACO instrument as described above, to quantify detected methane emissions sources (SM-S3).

Due to the limited scope of the study, measurement results presented here should not be construed as sufficient to develop emission factors for gathering pipelines in general. However, study measurements provide insight into the mix of emissions, and associated mathematical models provide guidance on the measurement requirements necessary to develop nationally-applicable emission factors.

Study area estimates

Monte Carlo methods (Ross, 2006) were utilized to estimate total emissions for the study area. Field measurements were utilized to model emissions, and emission drivers – commonly called activity data – were developed from public data and non-public partner data provided to the study team (SM-S4). Activity data were provided by the two study partners who provided both data and access to gathering lines, and one data partner who provided information on company equipment but did not provide access. Together, the study team had activity data for 98% of gathering pipeline length in the study area, as estimated from active well count (AOGC, 2016) – a level of completeness unique to this study. The available activity data are summarized in **Table 1**. All companies provided pipeline lengths and material type.

For auxiliary equipment, emissions were modeled exclusively using measurements made in the field campaign. Auxiliary equipment counts were available from one study partner and the data partner, and the study team estimated auxiliary equipment counts for the other study partner utilizing satellite imaging (SM-S4).

Two sources of uncertainty exist for emissions from pipeline leaks. First, it is unknown if the measured emission rate is representative of the mean emission rate of possible leaks within the study area. Therefore, this emission rate is modeled using a lognormal distribution. To develop the parameters for the distribution, the mean of the lognormal distribution was set to the size of the single leak observed in the field campaign and the standard deviation was estimated by analogy to leaks measured on distribution mains (Lamb et al., 2015). The development of the lognormal distribution, and comparison to the assumption of a triangular distribution, is described in SM-S4. Second, uncertainty also exists in the frequency at which leaks occur within the pipeline system. This uncertainty was modeled by analyzing the probability of finding one event (the observed leak) assuming a range of possible, but unknown, leak counts within the study population. This uncertainty analysis follows the method used by a previous study to characterize the frequency of rare large emitters in the transmission and storage sector (Zimmerle et al., 2015). For this study, we are interested in the probability of finding one pipeline leak while surveying 96 km of pipeline randomly selected from the total population of 3948 km of pipeline that could be screened for leaks. Given the number of leaks in the total population, the probability of identifying one leak is given by the hypergeometric distribution. Combining the probabilities for all possible total leak populations results in the probability distribution shown in **Figure 2** (SM-S4). For sample sizes that are small relative to the population, the

Table 1: Available activity data by operator in the study area. Partners 1 and 2 provided access to their gathering systems for measurement. The data partner provided activity data but no access. Combined, the three companies operate 98% of the active gas wells in the study area. DOI: https://doi.org/10.1525/elementa.258.t1

	Study Partner 1	Study Partner 2	Data Partner	Summary Information
Pipeline Length	✓	✓	✓	4683 km
Pipeline Type	✓	✓	✓	69% Polyethylene
Pig Launchers	✓	E	✓	3539 [3342 to 3753]
Block Valves	E	E	✓	2322 [2250 to 2404]

✓ = Reported, E = estimated via satellite imagery.
For categories where activity data was estimated, 95% confidence intervals are provided for count estimates.

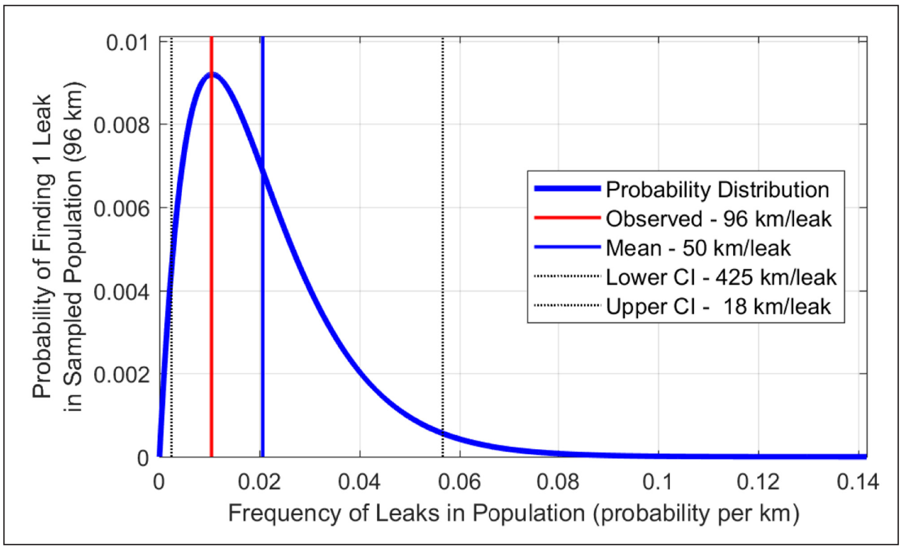

Figure 2: Uncertainty in frequency of underground pipeline leaks. This figure displays the probability distribution of total leak count in the study area, based upon finding 1 pipeline leak in 96 km of measured pipeline. DOI: https://doi.org/10.1525/elementa.258.f2

mode matches the leak frequency from the field campaign, but the distribution has a strong upward skew which shifts the mean leak frequency above the frequency seen in the field campaign. In practical terms, this distribution indicates that there is a substantial probability that the number of leaks found in a small survey is an underestimate of the mean leak frequency. Skew becomes less pronounced as the sampled proportion of the population increases. For the sample size in this study, the upward skew results in a mean probability of twice the field campaign (50 km/leak) and a wide, asymmetric, 95% confidence interval (CI) of 18 to 425 km/leak. This analysis provides an estimate of the uncertainty inherent in finding rare events given a limited sample size. The same distribution is also utilized to analyze the coverage required in future pipeline studies to provide an upper bound on emissions from gathering pipeline leaks.

In addition to steady state emissions from gathering lines and auxiliary equipment, there are additional episodic emissions when pig launchers and receivers are vented during launch and receive operations. These emissions were not measured due to the high instantaneous emissions rate during venting. Instead, emissions from each pig launch/receive event were calculated based upon geometry of vessel, pressure before release, average ground temperature, and gas composition (SM-S4).

The study estimate is compared with the EPA's greenhouse gas inventory (GHGI), and greenhouse gas reporting program (GHGRP), as well as measurements of distribution mains made in a recent study (Lamb et al., 2015). We localize emissions estimates to the study area by utilizing activity estimates developed in this study combined with emission factors from the GHGI, the GHGRP, and the Lamb study. Since these methods/sources stratify pipelines by material (steel or plastic), pipeline length by material type was estimated for all pipelines in the study area. Since the GHGRP and GHGI do not call out emissions from auxiliary equipment as a separate emissions source, and the auxiliary equipment on distribution systems differs from that on gathering systems, comparisons focus exclusively on pipeline leaks.

Finally, an empirical 95% confidence interval (CI) is utilized throughout, defined as the 2.5%/97.5% percentiles for two-sided analyses, and 0%/95% when discussing pipeline screening guidelines for future studies.

Results and discussion

Field measurements

We first consider measurement results for the field campaign, which are summarized in **Table 2**, and detailed in the SM spreadsheet. The field campaign surveyed 95 auxiliary equipment locations and detected 98 total leaks, of which 72% originated from valve packing. While the underlying cause of each leak is unknown, field operators report that valve packing must often be loosened prior to operating a valve during pigging operations or to allow a blocking valve to be turned by hand, and it is possible the packing was not re-tightened sufficiently after the operation was complete, resulting in a fugitive emission. The remaining detected leaks were from pig launcher doors (13%), flanges (12%), and gauges (2%). A total of 0.83 kg CH_4/hr of emissions were measured, with valves contributing 49%, pig launcher doors 47%, flanges 3% and gauges 1%. There was no statistical difference in auxiliary equipment emissions between the two partner companies (SM-S4). This study did not detect any failures of auxiliary equipment releasing gas at high rates, nor did it estimate the frequency at which such failures may occur.

A single underground pipeline emission, measured at 4.0 kg CH_4/hr, was found while screening a total of 96 km of pipeline. This raises the question of how effective the VMS was in detecting underground pipeline leaks. While the detection efficacy of the VMS could not be assessed with controlled studies in gathering pipeline conditions, there is high confidence in use of the method since it has been utilized successfully in recent distribution pipeline

Table 2: Summary of emission measurements. DOI: https://doi.org/10.1525/elementa.258.t2

Auxiliary Equipment Type	Locations Screened[1]	Locations with Detected Methane Enhancements[3]		Locations with Measurable Emissions[4]		Measured Methane Emissions Rates (kg CH_4/hr)	
		Count	Fraction	Count	Fraction	Mean	95% CI
Pigging facilities	56	42	75%	28	50%	0.014	–52%/+65%
Block valves	39	17	44%	6	15%	0.002	–56%/+74%
Pipeline leaks	96 km	1	NA	1	NA	4.0	NA[2]

Notes: NA = Not Applicable, CI = Confidence Interval.
[1] Pigging facilities and blocking valves were screened utilizing a laser gas detector (Heath, Inc. RMLD). Pipeline leaks were screened utilizing a vehicle-mounted methane mixing ratio instrument.
[2] Only one leak was detected, providing insufficient information to estimate a confidence interval on the leak rate.
[3] Indicates the number and fraction of screened locations where leak detection instruments indicated the presence of an emission.
[4] "Measurable emissions" indicates the count of locations where the measured emissions exceeded the lower measurement limit of the high-flow instrument, i.e. were distinguishable from zero emissions.

studies. However, to assess the chance that the VMS "missed a leak," the study conducted a qualitative post-campaign analysis of the VMS's detection sensitivity. All methane enhancements seen by the VMS are summarized in **Figure 3a**. For the single pipeline leak identified in this study (4 kg CH_4/hr), the VMS noted a maximum methane mixing ratio of 11,160 ppm, in a clearly defined peak, and methane enhancements were above 10 ppm up to 37 m away from the emission source, as seen in **Figure 3b**. To determine if the VMS would have detected smaller emission rates, the mixing ratios recorded by the VMS were reviewed for locations when the VMS was within 50 m of identified emissions from above-ground auxiliary equipment. Since these sources were independently screened and measured, reviewing atmospheric mixing ratios seen by the VMS provides an independent check of the VMS's capabilities. Qualitatively, a review would expect to see elevated methane mixing ratios – defined here as 3 ppm above the background mixing ratio of 1.9 ppm – when the VMS was near auxiliary equipment emissions. An example, shown in **Figure 3c**, indicates that the VMS detected an enhancement when 7 m from a 0.087 kg CH_4/hr emission source, and peaked at 36 ppm when 1.2 m away from the emission source. Additional examples are provided in SM-S3. This qualitative analysis indicates that the VMS would likely have identified pipeline methane emissions one to two orders of magnitude smaller than the single underground pipeline leak detected during the study, assuming the gas was emitted to atmosphere within the ROW and/or upwind of the VMS. Therefore, it is a reasonable assumption that either (a) the single leak detected here is the only underground pipeline leak in the ROWs measured during the study, *or*, (b) any undetected leaks were substantially smaller than 4 kg CH_4/hr.

Using methods described earlier, our analysis indicates that planned episodic emissions are small relative to other gathering pipeline emission sources: There were 13 pigging operations during the measurement campaign, which contributed an estimated 31 kg of emitted methane, or 1.3 % of the 2430 kg (4.8 kg CH_4/hr) of the measured methane emissions from pipelines and auxiliary equipment during the same period. No pipeline blowdowns occurred during the field study. Therefore, to simplify the analysis presented here, planned episodic emissions are not included in the analysis below but are reported in SM-S4. Unplanned episodic emissions (e.g. a pipeline breach) were not analyzed in this study.

Estimated gathering pipeline emissions for the study area

Table 3 summarizes the simulated methane emissions for gathering pipeline systems in the study area, termed the "study estimate", which was developed using the Monte Carlo methods described earlier. Simulation results estimate total study area methane emissions to be 402 [95 to 1065] kg CH_4/hr. Underground pipeline leaks dominate the total, contributing 93% [79% to 98%] of mean estimated methane emissions. Additionally, the uncertainty in leak frequency – number of pipeline leaks per km of pipeline – dominates the confidence interval.

Due to the number of auxiliary components measured and the number of leak measurements, the CI's for auxiliary equipment emissions are much tighter (approximately ±15%). Auxiliary equipment contributes, on average, 7% [2% to 21%] of total emissions. Most emissions detected on auxiliary equipment could be eliminated by screening for emissions after maintenance operations and tightening valve packing or seal latches on pig launchers. However, it should be emphasized that such control actions would eliminate only 7% of gathering pipeline emissions based upon this study's results. Emission rates for auxiliary equipment across the entire basin are significantly below that of other infrastructure in the gathering sector. For example, a 2015 national study (Marchese et al., 2015) measured 13 gathering compressor stations in Arkansas and found an average facility-level emission rate of 99 kg CH_4/hr, which is larger than the estimated mean emissions from *all* auxiliary pipeline equipment in the basin. Given an estimated 120 compressor stations in the study area, and assuming that no auxiliary equipment components have undetected major malfunctions, measurements completed here indicate that auxiliary equipment emissions approach negligibility relative to other gathering emission sources.

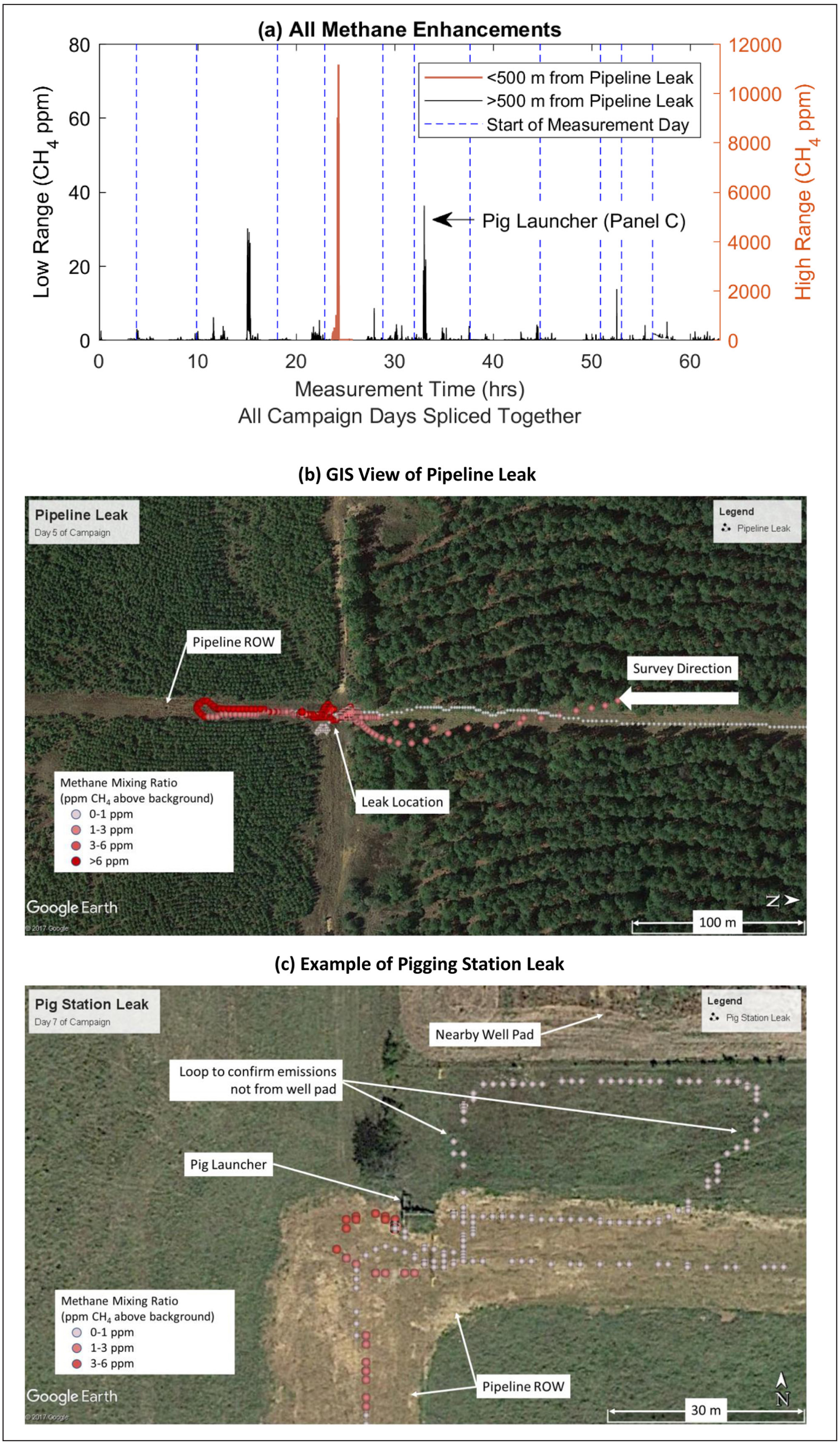

Figure 3: Summary and examples of field measurement data. Panel **(a)** shows methane enhancements for all measurement days, spliced into a single timeline, using the high range (right) axis for enhancements within 500 m of the pipeline leak location and the low range (left) axis for the remainder of the measurements. Panel **(b)** shows the field data for the pipeline leak superimposed over satellite imagery near the leak location. Panel **(c)** illustrates methane enhancements seen by the vehicle-mounted measurement system near a pig launcher leaking at approximately 87 g CH_4/hr. Images from Google Earth Pro™. DOI: https://doi.org/10.1525/elementa.258.f3

In contrast, the estimated 382 [75 to 1045] kg CH_4/hr estimated for pipeline leaks is not negligible. The measured leak, 4 kg CH_4/hr, approaches the facility-level emission rate of the lowest-emitting gathering stations measured in Arkansas in the Marchese study (7.5 ± 2.3 kg CH_4/hr). With due caution caused by the small sample size available here, pipeline leaks are comparable to other infrastructure, suggesting future measurement and analysis of gathering pipelines should focus on pipeline leak detection and measurement.

The study estimate is compared to other studies in **Figure 4** (SM-S4 & SM-S5). The comparison utilizes activity data developed in this study and emission factors from the GHGRP (US CFR, n.d.), the 2015 GHGI (EPA, 2015), and recent emissions data for distribution mains (Lamb et al., 2015). Since all methods utilize this study's activity estimate, comparisons focus only on differences in emission rates for the mix of pipeline equipment in the study area. Since GHGRP emission factors are provided without CI's, only the mean estimate is shown. The probability distribution of the GHGI emission factors were estimated from 90% CI's listed in the GRI/EPA report used to develop the emission factors (GRI/EPA, 1996).

The CI of the GHGI-based estimate overlaps the CI of the study estimate, and the GHGRP-based estimate falls within the CI of the study estimate. Therefore, this study provides no evidence of issues with the GHGI and GHGRP emission factors for the study area. Since the infrastructure in this basin is newer than most basins, and wet gas production may have different impacts on gathering line emissions, the agreement noted here should not be construed as representative of other basins.

Table 3: Simulation results for the study area. DOI: https://doi.org/10.1525/elementa.258.t3

Emission Component	Study Model Estimate		Mean Fraction of Emissions[4]	Confidence Interval for Fraction of Emissions[3]
	Mean (kg CH_4/hr)	95% Confidence Interval		
Pig Launchers[1]	15	+15%/–14%	6.0%	1% to 16%
Block Valves[1]	4	+15%/–14%	1.5%	0.4% to 4%
Pipeline Leaks[2]	382	+173%/–80%	93%	79% to 98%
Study Area Total	402	+165%/–76%	100%	–

Notes:
[1] Confidence interval considers both range of emissions rates measured and uncertainty in the activity estimates.
[2] Confidence interval considers uncertainty in the frequency of leak detection, and assumes a lognormal distribution for emission rate estimates.
[3] Minimum and maximum source contribution to gathering pipeline network emissions.
[4] Reported percentages are rounded independently and may not sum to 100%.

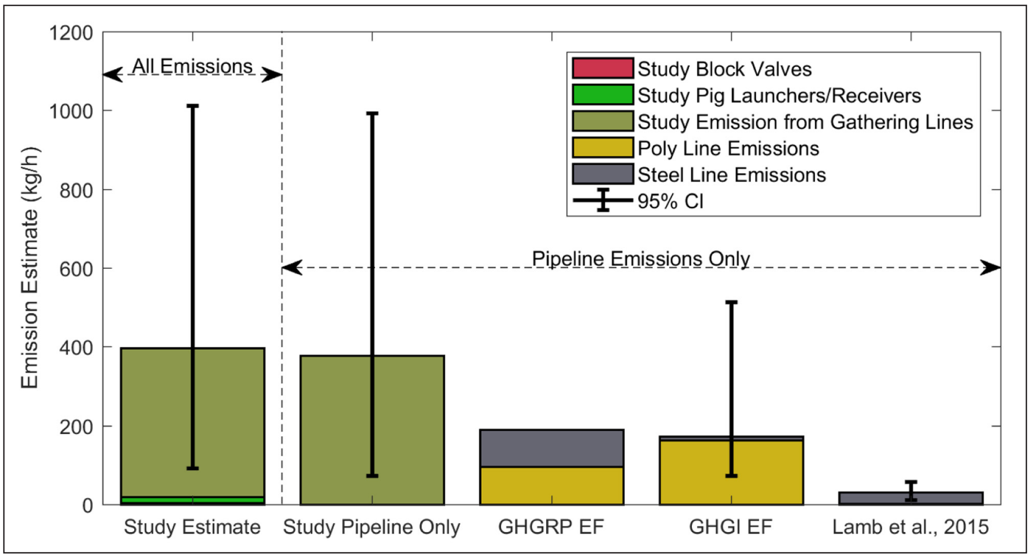

Figure 4: Comparison of the study estimate to other emission estimates. All estimates utilize emission factors from the referenced study and activity estimates developed in this study for the study area. The leftmost bar summarizes all emissions simulated in the study, while remaining bars compare emissions estimates for only pipeline leaks. Estimates using emission factors from both the greenhouse gas inventory (GHGI) and greenhouse gas reporting program (GHGRP) are statistically similar to results from this study. In contrast, estimates based upon emission factors from a prior study of distribution mains (Lamb et al., 2015) are not statistically similar. DOI: https://doi.org/10.1525/elementa.258.f4

The comparison with the distribution estimate is included because past revisions of the GHGI have utilized distribution mains as a source for gathering line emission factors. In this comparison, confidence intervals of the study estimate do not overlap with emissions estimated using emission factors from (Lamb et al., 2015). Therefore, measurements performed here indicate that emission factors based upon *new* distribution pipeline measurements *should not* be utilized to estimate gathering pipeline emissions. Instead, additional measurements should be made on a representative sample of gathering pipelines.

Pipeline screening guidelines for future studies

The current study indicates that pipeline leaks are rare events in the study area. The uncertainty analysis presented above provides a conceptual model to understand how the frequency of these rare events contributes to uncertainty in the resulting emissions estimates. Using this conceptual model, it is possible to pose the question: What size of field campaign would be necessary to constrain uncertainty associated with estimates of pipeline leak emissions to a desired fraction of total basin emissions?

To exercise this conceptual model, it is first necessary to define a frequency range over which pipeline leaks *might* occur. Given that range, it is possible to explore the fraction of a basin that would need to be screened and measured to meet the desired constraint on emissions estimates. Leak surveys are occasionally completed for operators, but unfortunately are seldom published. To estimate the range of frequencies, the authors contacted several organizations which had done recent leak surveys, and several agreed to provide data under the condition of confidentiality. In all cases, leaks were detected, but not measured:

- A leak detection survey of 595 km of an old gathering system in Pennsylvania indicated approximately 0.3 km per leak, of which 10% were large enough to be audible (Abele, 2016).
- A helicopter survey (with an unknown lower detection limit) of a variety of pipeline types found 16,000 leaks in 225,000 km of survey, or ≈14 km per leak.
- An operator managing 790 km of newer, low-pressure pipeline reports "less than 5 underground leaks" in two years. Assuming all leaks remained un-reported for six months, this would translate into a leak frequency of ≈160 km per leak.

These qualitative data indicate leak frequency ranging from 0.3 to 160 km/leak. The current study's data of 96 km/leak is somewhat centered within the reported range and our estimated CI (18–425 km/leak) includes the low-frequency (160 km/leak), but not the high-frequency end of the range (0.3 km/leak). This is unsurprising, as the pipelines measured in this study are typically no more than 10 years old, in contrast to the data above, which indicate that pipelines with high leak frequencies occur in regions with older pipelines where corrosion and/or other damage may be more prevalent.

Figure 5 shows simulation results for five leak frequencies for a basin pipeline length similar to that sampled

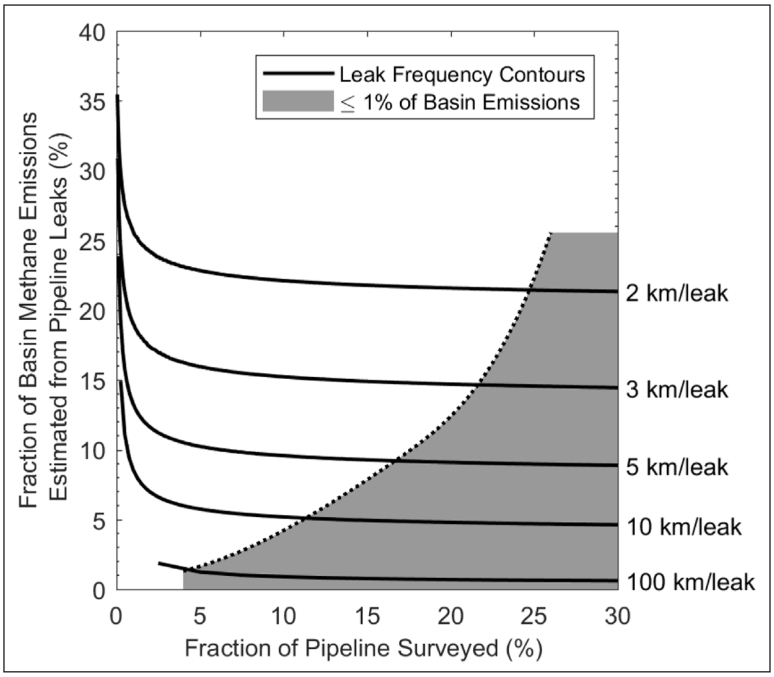

Figure 5: Required survey size to achieve a 95% confidence that any underestimate of emissions from gathering pipeline measurements is less than one percent total basin emissions. Pipeline leaks are estimated using an emission factor of 4 kg CH_4/hr per leak and estimated emissions are normalized by Peischl et al.'s estimate of 39 Mg/h from the eastern Fayetteville Shale. The shaded region indicates fraction of pipeline measured in the basin where a study team will improve the estimate of total emissions by less than 1% of total basin emissions. DOI: https://doi.org/10.1525/elementa.258.f5

in this campaign – approximately 4000 km of gathering pipeline. The simulation assumes a leak emission factor of 4 kg CH_4/hr for all pipeline leaks. We also assume that total emissions from all sources in this hypothetical basin can be estimated using Peischl's measurement of the eastern Fayetteville shale (Peischl et al., 2015). The bounding question is: Assuming a leak frequency is available *a priori* from other data (e.g. leak surveys), what fraction of the gathering pipelines in the study area would need to be measured to constrain uncertainty in the resulting pipeline leak emissions estimate to within 1% of the region's total emissions? For this analysis we compare the upper, one-sided, 95% confidence limit of our leak estimate to the mean Peischl estimate of total study area emissions (SM-S6).

Figure 5 provides the upper 95% confidence limit as a fraction of the Peischl estimate for a range of leak frequencies. In areas where leaks occur less frequently than 1 leak per 100 km of pipeline, a field campaign measuring 5% of the basin pipeline would constrain any underestimate of emissions from gathering pipelines to be less than 1% of total basin emissions. The current study measured 2.4% of the basin and found 1 leak in 96 km of pipeline. Therefore, the uncertainty analysis indicates that measuring approximately twice the pipeline length as this study (≈200 km), and finding no more than two pipeline leaks, the upper bound on emissions would be in error by no more than 1% of total study area emissions. For basins with higher leak frequencies, pipeline emissions account for a larger fraction of total emissions, and relatively more pipeline must be measured to reduce uncertainty in the total leak count. For example, for areas with leak frequencies of 1 leak in 2 km, 25% of the pipeline network must be measured to constrain uncertainty to within 1% of total basin emissions.

Conclusions

Field measurements indicate that above-ground equipment exhibit emissions that are small relative to other sources in the gathering system within the study area. Underground pipeline leaks are more challenging to detect, isolate and measure than auxiliary equipment, but study results show that a single underground leak can dominate total emissions. Gas mixing ratios near the leak location may also exceed lower explosive limits, providing a safety incentive to find and fix these issues. Assuming the observations of this study hold for other basins, these data suggest future emissions studies should focus on detecting underground pipeline leaks and devote relatively fewer resources to characterizing above-ground auxiliary equipment.

Field campaign experience in this study also suggests that emissions from underground leaks can be characterized with random screening of pipeline systems, but the fraction of the pipeline length to screen is strongly dependent upon the number of leaks found. Establishing an *a priori* "estimated leak frequency" for a gathering system, potentially through periodic screening, would provide system-specific guidance on how much of the pipeline system would need to be subjected to leak detection and measurement in order to constrain uncertainty in emissions estimates to be less than a given fraction of total emissions in the basin or system.

Data Accessibility Statement

Datasets produced in this work are available as online supplementary material accompanying this publication.

Supplemental Files

The supplemental files for this article can be found as follows:

- **S1.** Description of Gathering Lines and Auxiliary Equipment. DOI: https://doi.org/10.1525/elementa.258.s1
- **S2.** Study Area Definition and Pipeline Selection. DOI: https://doi.org/10.1525/elementa.258.s1
- **S3.** Measurement Equipment used in Study. DOI: https://doi.org/10.1525/elementa.258.s1
- **S4.** Measurement and Modeling Methods. DOI: https://doi.org/10.1525/elementa.258.s1
- **S5.** Results & Study Comparisons. DOI: https://doi.org/10.1525/elementa.258.s1
- **S6.** Future Gathering Pipeline Measurements. DOI: https://doi.org/10.1525/elementa.258.s1
- **Dataset S1.** Gathering Pipeline SM Data.xlsx. DOI: https://doi.org/10.1525/elementa.258.s2

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Competing interests

The authors have no competing interests to declare.

Author contributions

- Contributed to conception and design: DJZ, GAH, DN, GP
- Contributed to acquisition of data: CKP, CSB, TLV
- Contributed to analysis and interpretation of data: DJZ, CKP
- Drafted and/or revised the article: DJZ, CKP, CSB, GAH, DN, GP, TLV

- Approved the submitted version for publication: DJZ, CKP, CSB, GAH, DN, GP, TLV

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