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Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites

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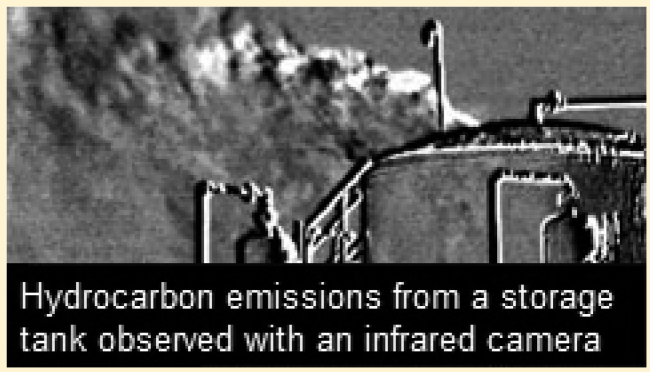
Supporting Information

ABSTRACT: Oil and gas (O&G) well pads with high hydrocarbon emission rates may disproportionally contribute to total methane and volatile organic compound (VOC) emissions from the production sector. In turn, these emissions may be missing from most bottom-up emission inventories. We performed helicopter-based infrared camera surveys of more than 8000 O&G well pads in seven U.S. basins to assess the prevalence and distribution of high-emitting hydrocarbon sources (detection threshold ~ 1−3 g s^{-1}). The proportion of sites with such high-emitting sources was 4% nationally but ranged from 1% in the Powder River (Wyoming) to 14% in the Bakken (North Dakota). Emissions were observed three times more frequently at sites in the oil-producing Bakken and oil-producing regions of mixed basins ($p < 0.0001$, χ^2 test). However, statistical models using basin and well pad characteristics explained 14% or less of the variance in observed emission patterns, indicating that stochastic processes dominate the occurrence of high emissions at individual sites. Over 90% of almost 500 detected sources were from tank vents and hatches. Although tank emissions may be partially attributable to flash gas, observed frequencies in most basins exceed those expected if emissions were effectively captured and controlled, demonstrating that tank emission control systems commonly underperform. Tanks represent a key mitigation opportunity for reducing methane and VOC emissions.



INTRODUCTION

Hydrocarbon emissions from oil and gas (O&G) facilities pose multiple risks to the environment and human health. Methane, the primary constituent of natural gas, is a short-lived greenhouse gas with 28−34 and 84−86 times the cumulative radiative forcing of carbon dioxide on a mass basis over 100 and 20 years, respectively.[1] Burning natural gas instead of other fossil fuels may increase net radiative forcing for some time, even if carbon dioxide emissions decline, depending on the loss rate of methane across the O&G supply chain.[2] O&G hydrocarbon emissions also include volatile organic compounds (VOCs), which are defined by the United States Environmental Protection Agency (U.S. EPA) as photochemically reactive organic compounds excluding methane and ethane. VOCs contribute to regional ozone formation and have been linked to elevated ozone levels in several O&G producing regions.[3,4] Certain VOCs such as benzene are toxic and may be connected to increased risk of cancer and respiratory disease in some areas with O&G development.[5,6]

Hydrocarbons (HC) can be emitted from vented, fugitive, or combustion sources. Vented HC emissions are intentional releases of natural gas from blowdowns (releasing gas to depressurize equipment for maintenance or safety) or sources that emit as part of routine operations such as pneumatic controllers. Fugitive HC emissions are unplanned releases from equipment leaks or malfunctioning equipment. Combustion HC emissions include uncombusted hydrocarbons in the exhaust of combustion sources such as compressor engines and flares. HC emissions can also occur from storage tanks for oil, natural gas condensate, and produced water. Tanks can be the source of both vented emissions, such as flashing losses when liquids are dumped from high-pressure separators to atmospheric pressure tanks, and fugitive emissions caused by

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malfunctioning separators or control devices. Unlike emissions of raw natural gas, which are primarily composed of methane, oil and condensate tank flashing emissions tend to be dominated by heavier alkanes such as propane and butane.[7]

Recent studies have used two broad approaches to estimate methane or VOC emissions: top-down methods that quantify emissions at the regional or larger scale at one or more points in time, and bottom-up methods that use activity data and emission factors to scale up component- or facility-level measurements to generate emission inventories. Generally, top-down estimates of methane emissions have been greater than bottom-up estimates.[8,9] In the Barnett Shale, a coordinated campaign with simultaneous top-down and bottom-up methods was able to reconcile aircraft mass balance estimates of regional O&G methane emissions with a custom emission inventory based on local and national facility-level measurements.[10,11] Compared to traditional bottom-up inventories, the coordinated campaign inventories estimated higher emissions due to more comprehensive activity data and the inclusion of high emission "superemitter" sites in the development of emission factors.[11,12]

Many types of O&G facilities have highly skewed emission distributions with a small fraction of sites contributing the majority of emissions.[13−17] These high emission facilities, often referred to as superemitters, may include some sites with persistent emissions and others with intermittent episodes of large releases.[18] High emission rates are likely due to both fugitive emissions caused by malfunctions and vented emissions such as tank flashing or blowdowns. The identification and mitigation of high emission sites is critical to reducing regional emissions since these facilities contribute a large portion of total O&G emissions.[18,19] If the identity of these sites can be predicted, then it would be effective to focus mitigation efforts on sites with characteristics most often associated with high emissions. However, if the occurrence of high emissions is stochastic, then the only viable mitigation solution would be frequent or continuous monitoring of all sites in order to quickly identify and mitigate those with excess emissions.

A common method to detect HC leaks at O&G facilities is optical gas imaging, which has been proposed by U.S. EPA as a regulatory requirement for new and modified sources.[20] Since methane and other HC emissions are invisible to the naked eye, infrared (IR) cameras are used to visualize HC plumes.[21] IR cameras can not differentiate individual HC species nor quantify emissions under field conditions, but their ability to identify the exact location of an emission source is highly valuable for mitigation. A skilled technician on the ground can use an IR camera to quickly survey thousands of components at an O&G facility for leaks.[22] Helicopter-based IR camera surveys have been used by operators and regulatory agencies to inspect large numbers of sites for high emission rate sources that may indicate equipment issues or noncompliance with environmental regulations.[23]

In this study, we use data collected during helicopter-based IR camera optical gas imaging surveys of more than 8000 O&G well pads to assess the prevalence and distribution of high-emitting HC sources in seven U.S. O&G basins. Survey data were analyzed to determine patterns and statistical relationships of observed emissions with well pad and operator parameters. In turn, observed frequencies of high emission sources were compared to predicted frequencies of observable tank flashing emissions with and without controls to assess if detected emission sources indicate the presence of malfunctioning emission control systems.

METHODS

Survey areas were selected by stratified random sampling in seven U.S. O&G basins accounting for 33% and 39% of U.S. oil and gas production, respectively: Bakken (North Dakota/Montana), Barnett (north central Texas), Eagle Ford (south Texas), Fayetteville (Arkansas), Marcellus (Appalachian Basin), Powder River (Wyoming/Montana), and Uintah (Utah). Subregions in each basin were selected on the basis of their suitability for helicopter surveys (<1500 m above sea level, unrestricted airspace) and subdivided into 10 × 10 km grid cells. Due to their large size, subregions in the Bakken, Marcellus, and Powder River were centered on areas with active drilling in northwest North Dakota, southwest Pennsylvania, and eastern Wyoming, respectively. Data on well pad characteristics for each of these subregions were obtained for wells with an active status from the production database Drillinginfo, which contains data compiled and cleaned from state databases.[24]

One or two defining characteristics were identified for each region that best characterized the heterogeneity of the basin's O&G production and could be the basis for stratified sampling. The selected strata were gas-oil ratio (GOR) in produced fluids (Barnett and Uintah), well age (Bakken), a combination of well age and GOR (Marcellus), and well type of oil, gas, or coal-bed gas (Powder River). These strata were chosen to reflect the distinguishing characteristics in each region (e.g., GOR does not vary greatly in the Bakken, so no meaningful stratification is possible along that dimension). Parameter thresholds separating strata were selected independently for each basin to divide grid cells into two or three quantiles of average parameter values. After assigning grids to strata based on their average parameters, a list of grids in each stratum was randomly selected for survey. In two basins, this design was not followed. In the Fayetteville, a single 20 × 20 km area was selected due to limited survey time and homogeneous production across the basin (dry gas without oil). In the Eagle Ford, two unstratified 40 × 15 km survey areas that each covered the basin's broad range in GOR were selected to facilitate efficient measurements by additional research aircraft. A map of surveyed basins is shown in Figure S1.

Survey area boundaries were provided to a professional firm with extensive experience performing leak detection surveys of O&G sites from a helicopter using optical gas imaging (Leak Surveys, Inc.).[25] Flights occurred from June to October 2014 using an R44 helicopter. The survey team identified O&G well pads, compressor stations, and small gas processing plants in the survey areas; for this paper, only data from active well pads are included in the analysis. Camera operators used a FLIR GasFindIR infrared camera to visually survey sites for detectable hydrocarbon plumes at an elevation of approximately 50 m above ground level. At each site with detected emissions, the survey team reported the site's latitude/longitude and the number and equipment type of each observed emission source. Additionally, an IR video was recorded at each site with detected emissions, typically by circling the site and focusing on observed emission sources for 20 to 80 s. Videos were reviewed by the lead author to verify the number and type of detected sources.

Two independent methods were used to estimate the minimum detection limit of optical gas imaging with an IR

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camera deployed from the survey helicopter. First, an operator in the Fayetteville performed a controlled release of dry natural gas (97% CH_4) from a pipeline pig receiver at a midstream facility while being observed by the helicopter survey team from a typical survey position during cloudy conditions. A variable orifice was used to release natural gas at three rates. These rates were quantified by the bagging method at ~3, 8, and 27 g s^{-1}, respectively. The helicopter survey team recorded observable plumes from all three controlled release tests with the lowest release rate producing only faint images that appeared to represent the detection threshold under test conditions. Second, an aircraft with a methane analyzer used the atmospheric budget method to quantify methane emissions at 19 well pads and compressor stations within 1 h of detection by the helicopter survey team (See the Supporting Information for methodological details). Measured site emission rates ranged from 1 to 24 g CH_4 s^{-1} with 84% of central estimates above 3 g CH_4 s^{-1} (Table S1). Additionally, the helicopter survey team qualitatively ranked the size of emission sources based on the apparent size and density of plumes, but there was no correlation between the qualitative magnitude of emission sources estimated from experienced camera operators and the quantified methane emission rates; potential reasons are discussed in the Supporting Information. Variability in the IR camera's sensitivity to different hydrocarbons (HC) is expected to impact the detection limit. The GasFindIR camera can detect at least 20 different HCs with differing functionality and has the highest sensitivity to alkanes; the reported minimum detectable emission rate under controlled conditions is 2−4 times lower for propane than methane under controlled conditions.[21] While there may be differences in the ratio of minimum detectable emissions rates in the field compared to controlled conditions, a ratio of 3 was chosen as representative of the increased sensitivity of the camera to higher molecular weight HCs. Therefore, the helicopter survey detection limit was assumed to be ~3 g HC s^{-1} for dry gas sources with emissions composed primarily of methane and ~1 g HC s^{-1} for sources such as tanks with emissions composed primarily of higher HCs such as propane. The detection limit of the IR camera is also affected by wind speed. We assessed the average wind speed during surveys based on hourly data during daytime hours from local weather stations. Average wind speed ranged from 2.7 m s^{-1} in the Uintah to 6.4 m s^{-1} in the Powder River (Table S2). On the basis of the power law relationship between wind speed and detection limit reported in Benson et al., the difference in wind speed would cause the average detection limit to be 3−4 times higher in the Powder River compared to the Uintah.[21] Therefore, variability in wind speed contributes uncertainty to the detection limit of a similar magnitude as variable gas composition.

Because survey results were reported for unique well pads rather than by individual well (i.e., many sites had multiple wells), the latitude/longitude of individual wells in surveyed areas were used to aggregate wells into pads by spatially joining all active wells within a 50 m buffer distance.[18] For each pad, well-level data were used to determine the operator, well production type (oil, gas, oil and gas, coal bed methane), well drill type (vertical, horizontal, directional), number of wells, pad age (months since initial production of newest well), gas production, hydrocarbon liquid production, and water production.[24] Hydrocarbon liquid production includes both crude oil and natural gas condensate; for this analysis, the term "oil" is used to refer to all hydrocarbon liquids. Water production data were not available for individual wells in the Fayetteville or Marcellus basins. Parameters were specific to the same survey month for all basins except the Marcellus, for which only annual and semiannual data were available for conventional and unconventional wells, respectively. In addition to pad-specific parameters, operator-specific parameters were calculated for each basin based on operators' full population of wells in each basin. Surveyed sites with detected emissions were matched to individual pads in the survey area using the reported latitude/longitude as well as Google Earth imagery.

The helicopter-based team surveyed 8220 well pads located throughout an area of 6750 km^2. Average well pad characteristics by basin and strata are summarized in Table S3. The average number of wells per pad ranged from 1.1 in the Uintah to 2.7 in the Fayetteville. Well pads were newest in the Fayetteville (average age of newest well on each pad of 4.1 years) and oldest in the Barnett (13.4 years). Average gas production ranged from 65 Mcf pad^{-1} day^{-1} in the Uintah to 1438 Mcf pad^{-1} day^{-1} in the Fayetteville. Average oil production ranged from 0 bbl pad^{-1} day^{-1} in the Fayetteville to 312 bbl pad^{-1} day^{-1} in the Eagle Ford. For the basins with oil production, GOR was lowest in the Bakken (1.2 Mcf bbl^{-1}) and highest in the Marcellus (153 Mcf bbl^{-1}). To assess the representativeness of surveyed sites, we compared these parameters between surveyed sites and the total population of active wells in each basin in 2014 (Table S4). For almost all parameters, surveyed sites had statistically different distributions than the entire basin (Kolmogorov−Smirnov $p > 0.05$) but the percent difference for most values was <25% from the basin mean and almost always within 50%. In all basins, surveyed wells were younger than the full population; in the Bakken, Barnett, Eagle Ford, Marcellus, and Powder River, surveyed wells had higher gas production and/or oil production than the basin average. These slight biases likely resulted from selecting subregions with active drilling to include young sites in our survey areas. Overall, our sampled strata account for the full range of diversity within and across basins and are appropriate for assessing patterns in high emissions.

Pearson's correlation coefficients (r) were used to assess correlation between the presence (nondetect = 0, detect = 1) or number of detected emissions by source type and pad or operator parameters. Binomial generalized linear models (GLM), also known as logistic regression models, were used to predict the probability of detected emissions at a well pad (P_{detect}) from site and operator parameters. Analysis of variance models and Tukey's Honest Significance Difference test were used to assess significant differences in P_{detect} among basins, strata, well type, and drill type. Poisson GLMs were used to predict the number of detected sources by emission type at each pad. For the full data set and individual basins, several single parameter and multiparameter GLMs were evaluated on the basis of their simplicity, Akaike Information Criteria, Pearson's r, and Hosmer-Lemeshow goodness of fit between observed and predicted values to select models meaningful for explaining the effects of parameters on emissions. An alpha level of 0.05 was used to determine statistical significance in all tests. For statistical analyses, percent energy from oil was used as a surrogate for GOR since it has a discrete range and is more normally distributed; this metric was calculated from oil and gas production using an assumed energy content of 5.8 MMBtu bbl^{-1} for oil and 1.05 MMBtu Mcf^{-1} for natural gas.[26]

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Table 1. Infrared Camera Survey Results by Basin and Strata[a]

		detected sources				well pads with detected sources	
basin	strata	number	% tank vents	% tank hatches	% other sources	number	% of pads
Bakken	young	109	9%	83%	7%	57	14.9%[a]
	old	61	10%	85%	5%	37	12.4%[a]
	all surveyed	*170*	*9%*	*84%*	*6%*	*94*	*13.8%[w]*
Barnett	high GOR	10	60%	50%	0%	7	0.7%[a]
	medium GOR	9	22%	67%	11%	6	1.4%[a]
	low GOR	60	55%	40%	3%	46	20.6%[b]
	all surveyed	*79*	*52%*	*44%*	*4%*	*59*	*3.5%[y]*
Eagle Ford	east	70	61%	34%	3%	29	11.0%[a]
	west	1	0%	100%	0%	1	0.3%[b]
	all surveyed	*71*	*61%*	*35%*	*3%*	*30*	*5.4%[xy]*
Fayetteville	*all surveyed*	*24*	*17%*	*83%*	*0%*	*13*	*4.4%[xyz]*
Marcellus	high GOR, younger age	17	76%	12%	12%	13	1.4%[a]
	high GOR, older age	0				0	0.0%[b]
	low GOR	15	13%	87%	0%	11	10.7%[c]
	all surveyed	*32*	*47%*	*47%*	*6%*	*24*	*1.2%[z]*
Powder River	coal bed methane	0				0	0.0%[a]
	oil/CBM mix	0				0	0.0%[a]
	oil	18	44%	39%	22%	15	11.2%[b]
	all surveyed	*18*	*44%*	*39%*	*22%*	*15*	*1.0%[z]*
Uintah	high GOR	3	67%	0%	33%	3	2.2%[a]
	medium GOR	59	75%	5%	20%	52	6.3%[ab]
	low GOR	38	63%	21%	16%	37	8.8%[b]
	all surveyed	*100*	*70%*	*11%*	*19%*	*92*	*6.6%[x]*
all basins		494	40%	52%	8%	327	4.0%

[a]For the percentage of pads with detected emissions (P_{detect}), letters indicate statistically significant differences among strata within each basin (a−c) and among basins (w−z) as determined by Analysis of Variance models and Tukey's HSD ($p < 0.05$). For example, within the Barnett, P_{detect} in the low GOR strata is statistically different than the high GOR and medium GOR strata; the overall Barnett P_{detect} is statistically different than overall P_{detect} of the Bakken, Marcellus, Powder River, and Uintah.

Table 2. Correlation of Well Pad and Operator Parameters with P_{detect} (the Detection of Emissions at a Site; Nondetect = 0, Detect = 1) or the Number of Detected Sources by Type[a]

parameters		P_{detect}	total sources	tank vents	tank hatches	nontank sources
well pad parameters	well count	0.15	0.16	0.15	0.10	
	well age	−0.12	−0.10	−0.08	−0.07	−0.03
	gas production	0.12	0.11	0.15	0.04	
	oil production	0.20	0.28	0.24	0.19	
	water production	0.06	0.06	0.04	0.06	
	% energy from oil	0.19	0.16	0.10	0.12	0.06
operator regional parameters	well count	−0.11	−0.09	−0.06	−0.06	−0.05
	gas production	−0.05	−0.03	−0.03		−0.04
	oil production	0.09	0.10	0.06	0.08	
	water production	−0.06	−0.06	−0.04	−0.03	−0.06
	% energy from oil	0.17	0.14	0.08	0.12	0.06

[a]Well pad parameters represent the individual site. Operator parameters represent all regional well pads operated by the same company as each surveyed site. Reported values are Pearson correlation coefficients (r) that are significantly different than zero ($p < 0.05$).

■ RESULTS AND DISCUSSION

A total of 494 unique high emissions sources at 327 well pads were detected by the helicopter survey team out of 8220 surveyed well pads in seven basins. The percentage of total well pads with detected HC emissions (P_{detect}) was 4% but ranged from 1% in the Powder River to 14% in the Bakken (Table 1). There were statistically significant differences in P_{detect} by basin with the Bakken higher than all other basins (see Table 1 for full pairwise comparisons). Emissions were more often observed in oil-producing areas with an average P_{detect} of 13% in the Bakken and low gas-to-oil ratio strata of mixed production basins ($p < 0.0001$, χ^2 test). For example, in the Barnett, 21% of well pads in the low GOR strata showed detectable emissions compared to <1% of sites in the high GOR strata (Table 1). There were also significant differences in P_{detect} by well production type (oil and gas > oil > gas > coal bed methane) and well drill type (horizontal > directional and vertical).

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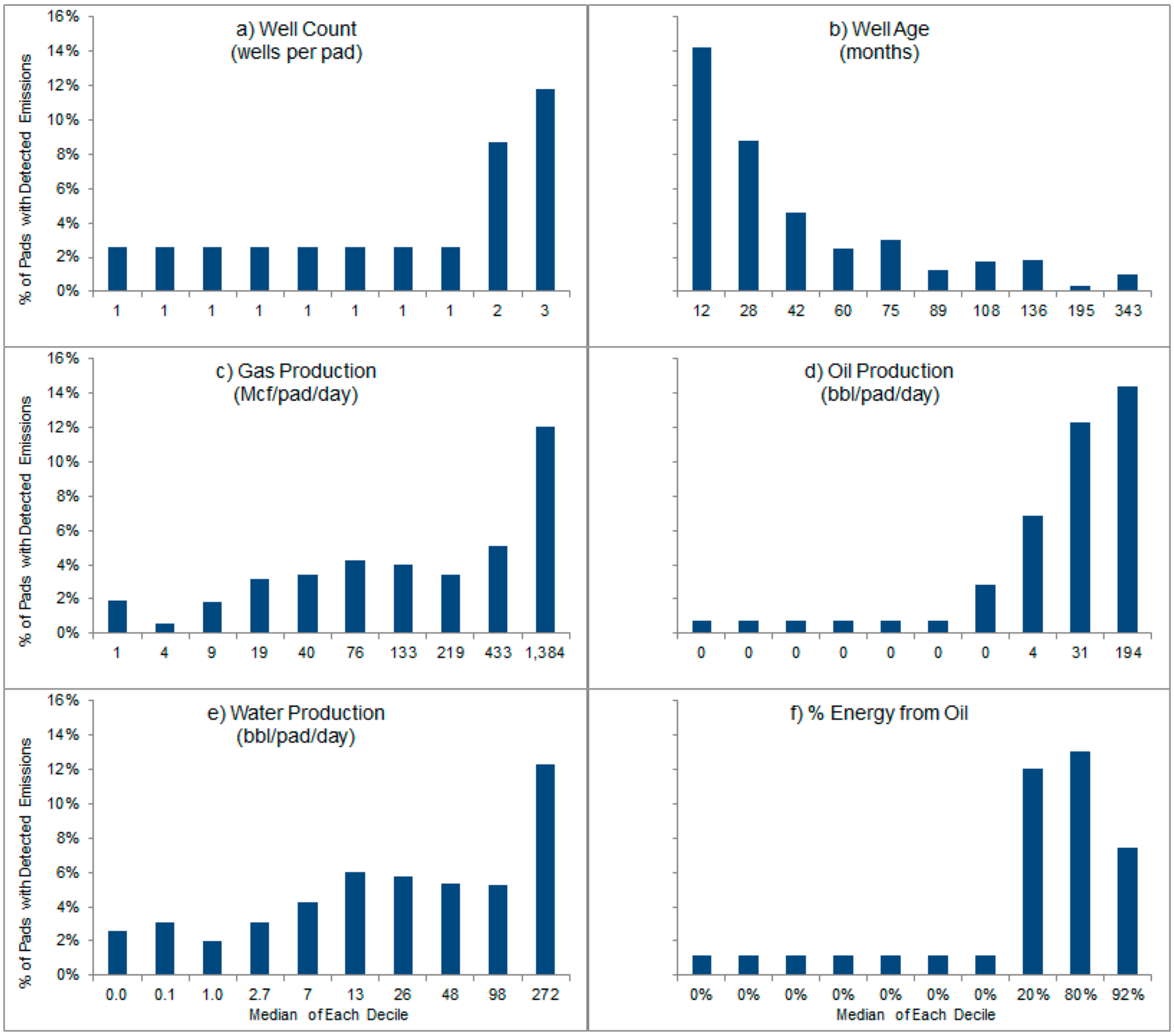

Figure 1. Percentage of well pads with detected emissions by deciles of well pad parameters: (a) well count (wells per pad), (b) well age (months since initial production of newest well), (c) gas production (Mcf/day), (d) oil production (bbl/day), (e) water production (bbl/day), and (f) % energy from oil. The median values of each decile are displayed on the *x*-axes.

Tank hatches and tank vents were the most common source type of detected emissions, comprising 92% of observed sources (Table 1). The remaining 8% of detected emission sources were dehydrators, separators, trucks unloading oil from tanks, and unlit or malfunctioning flares. Detected emission sources represent individual release points with HC emission rates exceeding the survey's estimated detection limit of approximately 3 g s^{-1} for CH_4 or 1 g s^{-1} for heavier HC. Given this detection limit, no emissions were observed from equipment leaks, pneumatic controllers, or chemical injection pumps, consistent with two recent studies that observed a maximum emission rate of 1.5 CH_4 g s^{-1} at over 1000 such measured sources.[27,28]

There are several factors that may account for differences among basins in P_{detect} including operational practices, emission control regulations, and the mix of produced hydrocarbons. The effect of weather conditions on the detection limit may also have impacted the frequency of observed emissions. In particular, the higher average wind speed in the Powder River may have contributed to the low frequency of observations.

Statistical Analyses. There were statistically significant but relatively weak positive correlations between detection and numerous well pad parameters: well count, gas production, oil production, water production, and percent energy from oil (Table 2; r = 0.06 to 0.20). Detection was negatively correlated with well age (r = −0.12), meaning that newer wells were more likely to have detected emissions. The average P_{detect} by decile of analyzed pad parameters is shown in Figure 1. One binomial generalized linear model, GLM A4, predicted detection that was not significantly different than that observed (Hosmer-Lemeshow >0.05); this multiparameter model used basin, the numerical pad parameters well count, well age, gas production, oil production, and percent energy from oil, and the interactions of basin with each numerical parameter, to explain 14% of the variance in P_{detect} (r^2 = 0.14). Three other multiparameter GLMs had observed and predicted detections that were statistically different and explained 3−8% of the variance: A1, using basin only; A2, using numerical parameters only; and A3, using basin and the numerical parameters but not their interactions (Table S5, r^2 = 0.03, 0.07, and 0.08, respectively). The increase in predictive power indicates that

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the effect of well pad numerical parameters on P_{detect} varies by basin. For example, in the Marcellus, Powder River, Barnett, and Uintah basins, which have a mix of produced hydrocarbons with a wide range of GOR, there was a significant positive effect of percent energy from oil on predicted P_{detect}, while there was no significant effect of this parameter in the basins with more homogeneous production.

The most predictive GLM, A4, only explained 14% of the variance, which indicates that the presence of high emissions was primarily stochastic or driven by operational characteristics not included in this analysis. Therefore, statistical models have limited utility for predicting the occurrence of individual high emission sources. However, the relatively weak, statistically significant correlation of several parameters with P_{detect} does provide some insights into factors affecting the likelihood of high emissions. To assess the effects of well pad characteristics on detection, we evaluated single parameter GLMs for the full data set and individual basins (Table S6). For the full data set, the GLMs with the best fit between observed and predicted detection were based on well age ($r^2 = 0.04$), oil production ($r^2 = 0.03$), and percent energy from oil ($r^2 = 0.03$). The relative strength of the effects of parameters on the likelihood of detection can be assessed by the ratio of GLM predicted P_{detect} at the 97.5th and 2.5th percentile of parameter distributions. For example, predicted probability of detection for a pad at the 97.5th percentile of well count ($P_{detect} = 0.11$; 5 wells per pad) is 3.2 times higher than for a pad at the 2.5th percentile ($P_{detect} = 0.03$; 1 well per pad). For individual basins, single parameter GLMs with statistically significant fits had the same directional effects as the full data set but varied in their relative strength. The best fit GLMs were based on well count in the Bakken and Marcellus, well age in the Powder River and Uintah, and oil production in the Barnett and Eagle Ford. In the Fayetteville, no single parameter GLM had a statistically significant fit. Detailed parameters for GLM A4 and single parameter GLMs are reported in Tables S16 and S17.

Other studies have reported a weak positive correlation between gas production and methane emissions.[13,28,29] In a prior study of the Barnett Shale, the top 7% of well pads by gas production were estimated to contribute 29% of total methane emissions; this was attributed to higher absolute emissions yet lower proportional loss rates of produced gas at high production sites.[18] The positive correlation between oil production and emission detection may be related to a higher frequency of tank flashing with increased oil production. Brantley et al. reported that oil production was negatively correlated with methane emissions as part of a multivariate linear regression model, which the authors attributed to lower methane content relative to heavier HCs in gas from oil producing wells.[13] In this study, the opposite effect would be expected since the IR camera detects all HCs with higher sensitivity to heavier HCs. The positive relationship between the number of wells per pad and P_{detect} may be due to greater complexity and potential emission sources at multiwell pads. The negative effect of well pad age, the parameter with the strongest predictive power, is likely related to the inverse relationship between well age and oil and gas production, although all parameters remain significant in multiparameter GLMs. Pads with a well in its first two months of production had over five times the frequency of detected emissions than older pads ($p < 0.001$). Due to the steep decline in production rates of unconventional wells with age, equipment and control devices may be undersized for handling this period of maximum production. Although older sites would be expected to have a greater likelihood of malfunctions caused by equipment wear, young sites may have initial issues caused by poor setup that have yet to be detected and repaired.

Similar statistical analyses were performed for basin-specific operator characteristics; there were several statistically significant but weak correlations between P_{detect} and these parameters (Table 2) with the strongest positive and negative correlations for an operator's regional percent energy from oil ($r = 0.17$) and regional well count ($r = -0.11$). Binomial GLMs predicting P_{detect} from operator parameters are described in the Supporting Information. Relationships between the number of detected emissions by source type and well pad or operator characteristics were also evaluated (Table 2). For tank vents and hatches, the number of detected sources at a pad was most strongly correlated with oil production ($r = 0.24$ and 0.19). For nontank sources, correlations were weaker ($r = -0.06$ to 0.06). Poisson GLMs predicting the number of detected sources by type from pad parameters are described in the Supporting Information.

Potential Causes of Observed Emissions. High-emitting sources detected by the survey team may have been caused by both malfunctions and normal operations. For nontank sources, IR videos provide evidence that most sources were the result of malfunctions or intentional releases. There were 14 observations of malfunctioning flares that were unlit or operating with poor combustion efficiency. Emissions were detected from the pressure relief valves of four separators; although these pressure relief valves may have been functioning properly for safety purposes, the overpressurization that triggered their release indicates abnormal operations. Eight emission sources were observed from vents associated with trucks unloading oil from tanks, which may be intentional to relieve pressure of gas that is released as oil is pumped into trucks. Fifteen dehydrators were observed to have HC emissions, primarily from still vents that remove water vapor from the water-saturated glycol solution. On the basis of pad gas production and HC emission factors, no more than three of these dehydrators would be expected to have still vent emissions close to the 1 g s^{-1} detection limit.[30] Therefore, most observed emissions from dehydrators were likely the result of abnormal operations that allowed excess HC to slip through the vent. In addition to the IR videos of individual sources, the very weak fit between observed and predicted emissions suggests that nontank emission sources are strongly driven by stochastic processes such as malfunctions.

Attributing tank vent and hatch emissions to malfunctions or normal operations is more difficult due to the many potential causes of tank emissions. As part of normal operations, uncontrolled tanks emit HCs from working, breathing, and flashing losses. Tank working and breathing losses generally are expected to be less than 1 g HC s^{-1}, but emissions in excess of this rate can occur from tank flashing after a separator dumps liquids into a tank.[13,31] As discussed below, the emission rate and frequency of tank flashing emissions can be predicted on the basis of parameters including oil production.

Another routine cause of tank emissions is when wells are vented to unload liquids accumulated in the wellbore, which also releases gas. Emissions from well unloadings can be very large; the average emission rate of over 100 measured unloading events was 111 g CH_4 s^{-1}.[32] U.S. EPA Greenhouse Gas Reporting Program (GHGRP) data were used to estimate the percentage of wells expected to be venting at any one time in surveyed basins.[33] Assuming the duration of unloading events was 1 h, 0.24% and 0.15% of wells in the Fayetteville

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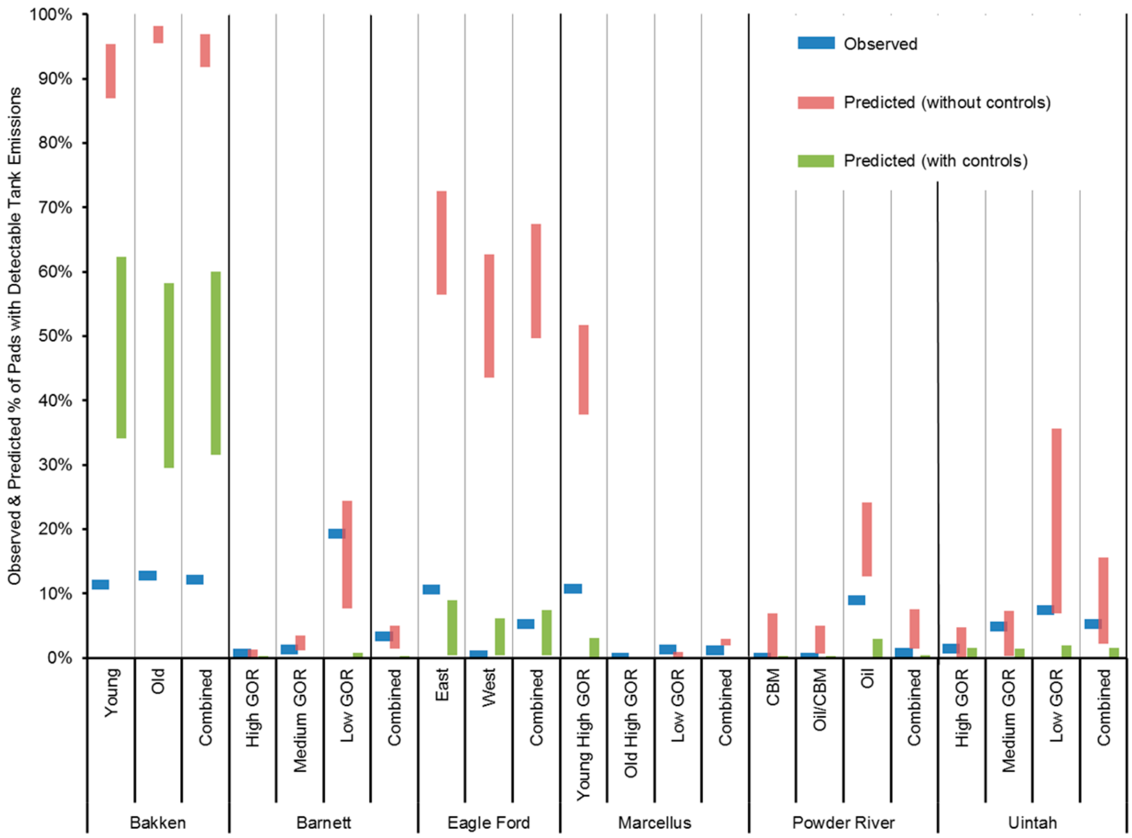

Figure 2. Comparison of the observed and predicted frequencies of well pads with detected tank hydrocarbon emissions assuming an observation threshold of 1 g s^{-1} and basin-level data from the EPA O&G Estimation Tool. Two sets of predicted estimates are provided: red bars reflect predicted frequencies based on potential emissions without controls; green bars reflect the application of controls to the highest emitting tanks (see text for details). Predicted frequencies are shown as a range reflecting different temporal profiles of tank flashing emissions. For several basins and strata, observed frequencies are lower than frequencies predicted without controls but higher than predicted with controls. For example, the combined Uintah observation of 5.8% is within the range predicted for potential emissions but greater than the maximum of 1.5% predicted if all tank control systems were functioning effectively.

(Arkoma) and Uintah basins would have been venting due to liquids unloading at any one time, respectively; all other surveyed basins are predicted to have had less than 0.1% of wells venting from unloading. Therefore, liquids unloading events likely could be detected by the helicopter survey but only can explain a small fraction of observed tank sources.

Finally, abnormal emissions can occur if a separator dump valve fails to properly close and allows produced gas to flow through the tank instead of the sales line. These sources can have very large emission rates, theoretically up to a well's entire gas production if the valve is stuck fully open. In 2014, operators reported over 7000 malfunctioning dump valves to the U.S. EPA GHGRP.[33] On the basis of the reported number of hydrocarbon tanks, approximately 5% of GHGRP tanks was associated with stuck dump valves. Operators do not report the duration of stuck dump valves, but a median duration of 7 days can be back calculated from other GHGRP data. Consequently, less than 0.1% of tanks are expected to have emissions from stuck dump valves at any one time.

Influence of Flashing Emissions by Basin. To determine if flashing could account for the observed P_{detect} of tank emission sources, potential HC emissions from tank flashing were estimated for surveyed well pads. Flash emission rates per unit of liquids production vary by parameters such as separator pressure and API gravity (a measure of HC liquid density). Since these values were not known for individual sites, basin-level data were obtained from the U.S. EPA O&G Emission Estimation Tool 2014 version 1, which includes a compilation of best available data from several sources including state regulatory agencies.[34] The tool provides separate emission factors for produced water, condensate, and crude oil (Table S11). For hydrocarbon liquids, a weighted average emission factor was derived from basin-level oil and condensate production. If tanks at a well pad are manifolded together with a common vent, then flash emissions will occur when any well's separator dumps to the tank battery. Therefore, site-level production was used as a conservatively high estimate of flashing emissions. The temporal variability of flash emissions depends on the frequency and duration of separator dumps and duration of subsequent flash gas venting. Brantley et al. reported that a tank at a Denver-Julesburg well pad producing 29 bbl d^{-1} condensate flashed ten times in 20 min; the duration of flash events in the study ranged from 30 to 120 s.[31] This indicates that, although individual flash events are short-lived, some sites may have near continuous tank flashing emissions due to frequent venting from separator dumps. To estimate the percentage of sites expected to have flash emissions ≥1 g HC s^{-1} detection limit at any one time, the frequency and emission rate of flash emissions were calculated using two sets of assumptions: continuous emissions at a constant rate or intermittent emissions at the detection limit. Both these estimates use the same daily average emission rate but serve

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as lower and upper bounds for the fraction of sites with concurrent emissions at or above the detection limit. The effects of these assumptions were tested with a sensitivity analysis including alternative emission factors and a 3 g HC s^{-1} detection limit (Tables S12–S15). In all basins, the range of predicted frequencies of sites with uncontrolled tank flashing emissions $\geq$1 g HC s^{-1} included or exceeded observed frequencies (Figure 2; Fayetteville was excluded due to lack of reported liquids production). This indicates that tank flashing could explain observed emissions in the absence of tank emission control devices.

There are several state and federal regulations that require some oil and condensate storage tanks to control VOC emissions, including in North Dakota, Pennsylvania, Utah, and Wyoming.[35,36] For example, during the time of the survey, U.S. EPA New Source Performance Standard Subpart OOOO required all tanks that began construction after April 12, 2013 and had a potential to emit $\geq$6 tons per year VOC to install control devices with at least 95% control effectiveness within 60 days of initial production.[37] Tank emission control devices include flares, combustors (enclosed flares), and vapor recovery units. The improper design, construction, or maintenance of tank control devices can reduce the capture or control efficiency of tank control devices.[38] Combustion devices can fail to ignite or have poor combustion efficiency, which causes HC emissions from the combustor stack. Emissions may not be fully captured if control systems are undersized or if condensed liquids in vent lines restrict the flow of gas, which can lead to tank overpressurization that triggers the release of gas from a pressure relief valve or tank hatch. Additionally, tank hatches that are left open accidentally or improperly sealed can allow some portion of vented flash gas to circumvent control devices. To determine if the frequency of observed tank emissions indicates failure of tank control systems, we estimated the percentage of sites expected to be equipped with tank controls by applying basin-level control data from the U.S. EPA O&G Emission Estimation Tool (Table S11).[34] For every surveyed well pad, potential emissions from oil, condensate, and water flashing were estimated with basin-level emission factors. Well pads were ranked by potential emissions, and then, controls were assumed to be equipped at a fraction of sites equal to the percentage of tanks with flares reported in the tool (28–86%). Emissions were assumed to be controlled at the reported basin-level capture efficiency (100%) and control efficiency (91–98%).[34] If these assumptions were true, then no emissions should be observed from hatches or vents of controlled tanks since all emissions are captured by the control device, but emissions could be observed exiting control devices if uncombusted HC in flare exhaust exceeds the detection limit.

In the Barnett, Powder River, Marcellus, and Uintah Basins, the observed frequency of well pads with detected tank emissions exceeded the maximum predicted frequency based on controlled tank flashing emissions, while in the Bakken the observed frequency was lower than expected (Figure 2). U.S. EPA recently issued a compliance alert that reports inspectors frequently observe emissions from tank hatches and pressure relief valves.[38] After an inspection of almost a hundred tanks in Colorado found numerous instances of ineffective control systems caused by design issues such as undersized control devices, an O&G operator entered a consent decree with U.S. EPA and the State of Colorado to evaluate and improve their control systems.[39] In the Bakken and Barnett, we inspected Google Earth imagery to assess the presence of tank control devices at well pads with observed tank emissions; 86% and 56% of well pads with extant imagery, respectively, had apparent control devices. This study's observation that tank hatches and vents were the origin of the majority of detected large emission sources, even at controlled sites, suggests that the U.S. EPA O&G Emission Estimation Tool's assumption of 100% capture efficiency is inaccurate and incomplete capture of emissions by tank control systems is a widespread issue.

Policy Implications. There are several strategies for reducing emissions from tanks, such as installing vapor recovery towers or stabilizers to reduce the vapor pressure of liquids entering tanks, properly sizing control equipment, and maintaining pressure relief valves and tank hatches to prevent leaks. Since this study found a higher frequency of detected emissions at sites within the first few months of production, controlling tank emissions as soon as a site enters production could reduce overall emissions. U.S. EPA New Source Performance Standard Subpart OOOO allows the installation of control devices to be delayed up to 60 days after startup, despite this being a period of maximum production, especially for unconventional wells characterized by rapid production decline.[37] The use of properly sized control devices as soon as production is initiated would address a substantial source of emissions. For example, the average Bakken site produces oil about twice the rate in the first two months as it does during the rest of the first year of production.[24] Given the evidence reported in this study that the frequency of observed tank emissions is greater than what would be expected if control systems were functioning effectively, it is clear that identifying anomalous emissions through regular or continuous monitoring of hydrocarbon emissions and/or equipment status, such as leak detection and repair programs, would be an effective strategy to reduce emissions.

Currently, U.S. EPA estimates total annual emissions from all oil and gas production sources of 3.1 Tg VOC and 2.9 Tg CH_4 with 0.6 Tg CH_4 yr^{-1} attributed to oil and condensate tanks.[40,41] The qualitative nature of the IR survey data precludes an accurate estimate of hydrocarbon or methane emissions, but with knowledge of the detection limit of the technology deployed, our observations can be used to estimate a lower bound for tank emissions. Our observation of more than 450 detected tank sources with emission rates $\geq$1 g HC s^{-1} represent at least 450 g HC s^{-1} (a more likely estimate is ~1575 g HC s^{-1} based on the median aircraft quantified well pad emission rate of 3.5 g CH_4 s^{-1}). While these emissions likely include both intermittent and continuous sources, the assumption of a relatively constant emission rate across a large number of sites is robust and yields an emission rate of at least 14.2 Gg HC yr^{-1}. Since our observations were limited to summer/fall and daylight hours, we were not able to assess how annual average prevalence may be affected by seasonal or diurnal trends such as higher tank breathing losses during warmer conditions. The 8220 surveyed well pads include 1.1%, 3.7%, and 4.5% of U.S. active wells, gas production, and oil production, respectively. There is uncertainty in scaling up emissions from our sample given that the representativeness of surveyed wells to the U.S. national population of O&G wells has not been assessed and there are only weak correlations between the prevalence of high emissions and these parameters. However, scaling up by the best fit parameter, oil production, yields a minimum national HC emission rate of 0.32 Tg yr^{-1} from high emission tank sources. This national emission estimate of tank emissions represents a lower bound for high-

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emitting tanks and excludes common, lower emission rate sources such as tank working and breathing losses. This study provides evidence that the cause of some observed emissions is anomalous conditions rather than routine, intermittent tank flashing. U.S. EPA may be underestimating emissions from O&G tanks by overestimating control effectiveness and failing to comprehensively include abnormal, high emission sources. It is reasonable to assume that tanks are a major contributor to the gap between top-down and bottom-up estimates of O&G CH_4 emissions reported by several studies, as well as to the fat-tail emissions observed in a previous study of the Barnett that closed the gap.[11]

Even though this study found statistically significant correlations between the presence of detected emissions and several well pad and operator parameters, these relationships were weak and GLM models were able to explain less than 15% of the variance. This low degree of predictability indicates that these large emission sources are primarily stochastic and the frequent and widespread inspection of sites to identify and repair high emission sources is critical to reducing emissions. In addition to helicopter-based IR surveys, continuous site-based and mobile leak detection systems may be valuable for quickly identifying these large sources.[13,14,42−44] Tank vents and hatches account for the vast majority of high emission sources detected at well pads across the U.S. Although routine tank flashing may be responsible for some of these emission sources, there is evidence that substantial emissions are caused by abnormal conditions such as ineffective tank control systems. Installing tank control devices on existing sources combined with maintenance and monitoring to ensure control systems are operating effectively would be an important step for reducing emissions of methane and VOCs. Tanks and other high emission sources are an important contributor to total hydrocarbon emissions from oil and gas well pads and offer a promising opportunity to reduce emissions, but further reductions targeting the numerous emission sources that are individually smaller but collectively large will also be necessary to minimize the health and climate impacts of oil and gas production.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.6b00705.

- 8 infrared videos and description of observed sources (ZIP)
- Supporting text, 17 tables, and 2 figures (PDF)
- Calculations used in tank flashing analysis (XLSX)
- Site-level parameter data for well pads in the surveyed areas and basins (XLSX)
- List of surveyed sites by latitude/longitude (XLSX)

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Notes

The authors declare no competing financial interest.

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