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RESEARCH ARTICLE

Aerial and ground-based optical gas imaging survey of Uinta Basin oil and gas wells

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We deployed a helicopter with an infrared optical gas imaging camera to detect hydrocarbon emissions from 3,428 oil and gas facilities (including 3,225 producing oil and gas well pads) in Utah's Uinta Basin during winter and spring 2018. We also surveyed 419 of the same well pads from the ground. Winter conditions led to poor contrast between emission plumes and the ground, leading to a detection limit for the aerial survey that was between two and six times worse than a previous summertime survey. Because the ground survey was able to use the camera's high-sensitivity mode, the rate of detected emission plumes was much higher in the ground survey (31% of all surveyed well pads) relative to the aerial survey (0.5%), but colder air temperatures appeared to impair plume detection in the ground survey as well. The aerial survey cost less per facility visited, but the ground survey cost less per emission plume detected.

Well pads with detected emissions during the ground and aerial surveys had higher oil and gas production, were younger, were more likely to be oil well pads, and had more liquid storage tanks per pad relative to the entire surveyed population. The majority of observed emission plumes were from liquid storage tanks (75.9% of all observed plumes), including emissions from pressure relief valves and thief hatches on the tank or from piping that connects to the tank. Well pads with control devices to reduce emissions from tanks (combustors or vapor recovery units) were more likely to have detected emissions. This finding does not imply that the control devices themselves were not functioning properly. Instead, gas was escaping into the atmosphere before it reached control devices. Pads with control devices tended to be newer and have higher oil and gas production, which probably explains their higher rate of detected emissions.

Keywords: Oil and gas; Optical gas imaging; Hydrocarbons; Emissions; FLIR GF320; Infrared camera

Introduction

Many recent studies have highlighted the impact of hydrocarbon emissions from the oil and gas industry on air quality and climate (Balcombe et al., 2018; Field et al., 2014). Basin-scale (Foster et al., 2017; Robertson et al., 2017; Schwietzke et al., 2017) and nation-scale (Bruhwiler et al., 2017; Miller et al., 2013; Omara et al., 2018) studies have improved understanding of the importance of oil and gas-related emissions. Millions of components at oil and gas sites are potential leak sources (Epperson et al., 2007; Schwietzke et al., 2018). Optical gas imaging cameras have emerged as a valuable tool to fill this need (Safitri et al., 2011).

Optical gas imaging cameras visualize a narrow band of the infrared spectrum in which methane and other hydrocarbons are absorptive (between 3 and 4 μm, depending on the make and model of the camera), allowing users to visualize hydrocarbon emission plumes that are invisible to the unaided eye. These cameras allow users to quickly and definitively locate natural gas emissions from oil and gas industry facilities and equipment. Use of these cameras within the oil and gas industry is widespread. U.S. Environmental Protection Agency (U.S. EPA) regulations require leak detection and repair at many oil and gas wells in the United States (CFR, 2016) and they allow operators to use optical gas imaging for this purpose. Government agencies also use optical gas imaging cameras for regulatory compliance inspections.

Scientific studies have shown the utility of optical gas imaging technology (Brantley et al., 2015; Lyon et al., 2016; Subramanian et al., 2015; Thoma et al., 2017) and have highlighted challenges to their use. This technology is qualitative, and the minimum detectable emission rate of optical gas imaging cameras is variable. Ultimately, the detectable emission rate depends on the amount of contrast in the camera image between the plume and the background behind the plume. Factors that influence contrast between the plume and the background include plume conditions (plume temperature, density and composition), the conditions of the background (temperature,

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reflectivity, and insolation), meteorology (which impacts both plume and background conditions), the distance of the camera from the emission source, camera settings, and the operator's experience and visual acuity (Fox et al., 2017; Mansfield et al., 2017; Ravikumar and Brandt, 2017; Ravikumar et al., 2016; Ravikumar et al., 2018).

Two previous optical gas imaging surveys of emissions from oil and gas production facilities have been conducted in Utah's Uinta Basin. The first was a helicopter-based survey conducted during summer 2014 by Lyon et al. (2016). Lyon et al. surveyed 1389 well pads over nine days and detected emissions from 6.6% of surveyed pads. Relative to the entire surveyed population, pads with detected emissions were newer, higher producing and more likely to be oil well pads. Almost all of the emissions observed by Lyon et al. were from liquid storage tanks. The second previous survey was a ground-based survey conducted during summer and fall 2016 by Mansfield et al. (2017). They surveyed 454 well pads from the ground at the edge of well pads and detected emissions from 39% of pads surveyed. All of the well pads surveyed by Mansfield et al. were oil well pads, all were constructed within the previous few years, and all had control devices installed to reduce emissions from liquid storage tanks. As with the Lyon et al. study, the majority of observed emissions in the Mansfield et al. study were from liquid storage tanks.

Here we present the results of simultaneous aerial and ground-based optical gas imaging surveys conducted in winter and spring 2018 using methods similar to Lyon et al. (2016) and Mansfield et al. (2017), respectively. We compare the results from aerial and ground-based survey platforms, make comparisons among all the optical gas imaging surveys that have been conducted in the Uinta Basin, and investigate the impacts of meteorological and surface conditions, well pad properties, pad ownership, and other factors on the frequency and qualitative size of detected emissions.

Methods

This study included an aerial optical gas imaging survey and two ground-based surveys of oil and gas wells in the Uinta Basin. **Table 1** provides a summary of data collected in this study and in previous optical gas imaging surveys that have been carried out in the Uinta Basin.

Aerial survey

We contracted with Leak Surveys, Inc. to conduct the aerial survey in late February and early March 2018. They used a FLIR GF320 camera from a helicopter at about 75 m above ground to survey for emissions at 3,428 oil and gas facilities, including well pads, compressor stations, and gas processing plants. Of the pads surveyed, 652 were also surveyed by Lyon et al. (2016) (19% of the facilities in this study, 47% of the pads in the Lyon et al. study).

Before the survey, we designated 29 rectangular areas in which Leak Surveys, Inc. would survey for emissions. These areas encompassed 44% of all producing well pads and 50% of compressor stations and gas plants in the Uinta Basin and included facilities operated by 28 different oil and gas companies. The helicopter survey crew flew back and forth across each area and briefly inspected each facility they encountered with the optical gas imaging camera. If they saw an emission plume, they circled the facility for 90 seconds while recording a video of the plume. They made a qualitative determination of whether the observed emission plume was small, medium, or large and recorded the number and location of emission sources. Plume size determinations were subjective and would have been influenced by plume, background, and meteorological conditions (Englander et al., 2018). During the aerial survey, the optical gas imaging camera operated in auto mode, rather than high-sensitivity mode. High sensitivity mode is an image processing technique that improves sensitivity, but it creates a grainy image that is difficult to interpret from the unstable platform of the moving helicopter.

Ground surveys

We used a FLIR GF320 camera to conduct the ground survey in February and early March 2018 (109 well pads; referred to herein as the winter ground survey), as well as in April and May 2018 (310 well pads; referred to herein as the spring ground survey). During the winter survey, the ground survey crew operated in the same rectangular areas and on the same days as the aerial survey, though the ground survey crew visited fewer well pads and fewer areas per day. During the spring survey, the survey crew operated in the same rectangular areas in which the aerial

Table 1: Summary of optical gas imaging surveys that have been conducted in the Uinta Basin. DOI: https://doi.org/10.1525/elementa.381.t1

	Time period	Camera	Type	Facilities surveyed	Producing well pads surveyed	Notes
Lyon et al.	Jul 2014	FLIR GF320	Aerial	1,389	1,389	
Mansfield et al.	Aug–Oct 2016	OpGal EyeCGas	Ground (at edge of pad)	454	454	Only pads with controlled tanks
Aerial survey (this study)	Feb–Mar 2018	FLIR GF320	Aerial	3,428	3,225	
Winter ground survey (this study)	Feb–Mar 2018	FLIR GF320	Ground (at edge of pad)	109	109	Synchronized with aerial
Spring ground survey (this study)	Apr–May 2018	FLIR GF320	Ground (at edge of pad)	310	310	

survey had been conducted, though the helicopter only operated during February and March. The ground crew only surveyed oil and gas well pads.

The ground crew surveyed from the edge of each well pad at the pad's access road. They used a tripod or the vehicle to stabilize the camera and spent several minutes at each pad scanning for emissions, including in the camera's auto-mode and high-sensitivity mode. If the ground survey crew detected emissions from any source, they recorded a video of the emissions. They made a qualitative determination of whether the observed emission plume was small, medium, or large and recorded how many distinct emission sources they observed and the observed source of the emissions. As with the aerial survey, plume size determinations were subjective and are expected to have been influenced by plume, background, and meteorological conditions.

At every well pad they surveyed, whether emissions were observed or not, the survey crew recorded their distance from the well pad's liquid storage tanks as determined by a rangefinder. They also recorded the number of liquid storage tanks at each well pad, the type of background that was behind the plume, and whether it was sunny. Meteorological instrumentation that measured temperature, humidity, barometric pressure, wind speed and direction, and solar radiation (spring survey only for solar radiation) was mounted to the top of the survey crew's vehicle. We calibrated meteorological instrumentation against NIST-traceable standards within the prior 12 months. The ground survey crew was not able to conduct surveys at pads where workovers or other maintenance activities were occurring because doing so would block the entrance of the pad, constituting a safety risk. Thus, we excluded these pads from the ground survey.

Industry involvement

We provided oil and gas companies whose facilities we surveyed with survey results within about 24 hours of the survey, and we provided videos as soon as we were able. After we sent videos and other final survey information, we asked companies at whose facilities emissions were observed to review the information we provided, visit locations where emissions were observed and provide feedback to us about sources of the observed emissions and any repairs that were made as a result of the survey.

Controlled propane releases

To determine the emission rates that were detectable from the helicopter and the ground under different conditions, we released commercial-grade propane (95% purity) at different emission rates from a 5 cm diameter vertical tube at about 2 m above ground. Emissions from well pad liquid storage tanks (the source of most emissions observed in this study) are comprised mostly of compounds heavier than methane and ethane, so propane is more appropriate than methane as a surrogate gas for these emissions (Hendler et al., 2009). Propane is also inexpensive and easier to store than methane and ethane. We measured the emission rate with a Fox model FT3 mass flow meter. All releases were carried out between 14:00 and 15:00 local time. During each release, we measured meteorological conditions with the system mounted atop the ground survey crew's vehicle. The ground survey crew viewed propane emissions at a distance of 50 m from the tube with the ground-based camera (the actual distance of the camera operator in the ground survey from liquid storage tanks on well pads was 58 ± 2 m). The helicopter crew viewed propane emissions at 50 m above ground on the first release day, and at 75 m on subsequent days.

Detection limit modeling

We used the method of Ravikumar et al. (2016) (also see Ravikumar and Brandt (2017) and Ravikumar et al. (2018)) to model the relationship between apparent ground temperature and detection limits during the aerial survey and for the period of the Lyon et al. (2016) study. The Ravikumar model uses measured meteorological conditions and surface properties to simulate radiance from the plume and the background. The model takes into account plume composition, emission size distribution, and distance from the plume, and the model has been validated against actual emission measurements (Ravikumar et al., 2016).

Cost calculations

Aerial survey costs used in this work are actual costs, rounded to the nearest $5,000. We separated helicopter mobilization costs from other costs since mobilization costs will vary depending on the helicopter's origin and destination, while other aerial survey costs are likely to be consistent regardless of the survey location. We assumed ground survey costs to include an hourly camera operator rate of $84.78 (ICF, 2016), as well as a $10,000 per-year maintenance and depreciation cost for the optical gas imaging camera (spread over 180 days of use per year) and 16 km driven per well pad (our ground crew's average actual travel distance) at a rate of $0.70 per mile (our ground crew's actual cost). We assumed an operator could survey 17.4 well pads per 8-h day, which was the average rate of our survey crew.

Data access, processing, and analysis

We obtained oil and gas facility information from the Utah Division of Oil, Gas and Mining (UDOGM, 2018). The aerial survey crew only recorded survey locations when emissions were detected, so we followed the method of Lyon et al. (2016) to produce a dataset of all the well pads within the survey area. We excluded pads that were not producing (using February 2018 production data) and we aggregated well information to the pad level (based on proximity of well heads to one another) since wells on multiple-well pads with shared equipment were counted as a single facility by the aerial survey crew. Pads with tanks with emissions controls (combustors or vapor recovery units) were identified based on the 2014 Utah air agencies oil and gas emissions inventory (UDAQ, 2018b), information received from well pad operators, and the ground survey crew's notes. We used the ground survey crew's counts of the number of tanks per pad for analyses of ground survey results, and we used the 2014 inventory data to obtain the number of tanks for the pads in the aerial survey. The inventory listed slightly fewer tanks per pad than the ground survey crew found (–0.1 (–0.3, 0.1) fewer tanks were listed in the inventory), which could have been due to counting errors or changes in well pad configurations between the 2014 inventory data collection and our 2018 survey. We calculated well pad age as the number of months since the the well(s) were completed at the pad.

We use units from the International System of Units, except in the case of oil and gas production data. For gas production, we use MCF, which is 1,000 feet^3 (28.3 m^3) of natural gas at 15.6°C and 101.3 kPa. For oil production, we use bbl (barrels), which is equivalent to 159 L.

In addition to the meteorological data collected for the ground survey, we used data from the Vernal airport to compare meteorological conditions during this study to those during the Lyon et al. (2016) survey, and for detection limit modeling. The Vernal airport is 64 km northeast of the geographic center of the survey areas. The survey areas spanned 147 km east to west and 78 km north to south. We obtained Vernal airport data from the National Climatic Data Center (NCDC, 2018). We used the MODIS Terra 500 m snow cover dataset (MODIS, 2018) to determine average percent snow cover for each survey area on each day of the aerial survey. For days during which a survey area had less than 50% data coverage in the MODIS dataset, we assumed that (1) the snow cover on the missed day was the average of the days before and after, or (2) the daily rate of change in snow cover in that area was the same as other survey areas with similar percent snow cover (if data coverage was less than 50% for two or more consecutive days).

We show average values as average (lower 90% confidence limit, upper 90% confidence limit) throughout the text. We calculated bootstrapped confidence intervals using the SciPy module in Python (with scikits.bootstrap). We give corellation results as r^2 values, and we calculated these and related p values using the Spearman rank correlation method, following Zar (2005). We used a 95% confidence threshold in the Monte Carlo analysis (see below).

In general, correlations of meteorological and well pad variables with detected emissions were poor, showing that the presence or absence of emission plumes was driven mostly by variables our study did not capture. This is a common finding for emissions datasets (Lyman et al., 2017; Lyon et al., 2016). Factors like well design, operator activities, and equipment malfunctions likely largely determine the frequency and severity of emission plumes, and these are factors our study design could not adequately account for. The analyses below mostly utilize data that have been averaged into bins (i.e., well pads with detected emissions compared to those without, data grouped by ambient temperature, etc.), since binning of data reduces the effects of outliers and improves statistical power (as many others have shown, for example Lyon et al. (2016), Schwietzke et al. (2017), Allen et al. (2015), and Edwards et al. (1994).

We calculated two metrics to characterize the statistics of observed emissions during the winter and spring ground surveys. These were (1) the number of observed emission plumes per well pad, and (2) a "severity score," intended to convey the qualitative size of emissions as observed by the survey crew. For the severity score, we assigned a value of 1 for plumes categorized as small, 2 for medium, and 3 for large. An average value was calculated for each well pad at which at least one emission is observed.

Monte Carlo analysis of company performance

We used a Monte Carlo analysis to determine whether emission plume detection results for individual companies were statistically significantly different from the mean for the entire dataset (Besag, 1992). For this analysis, M is the number of well pads in the entire dataset that belong to company X. The average emission detection result (i.e., plumes per pad or severity score) for company X is m_C. We generated a large number (10^6) of independent, random subsets of the results for the entire dataset, each subset containing M well pads. The result for each random subset is m_R, and p is the fraction of the time that m_R is less than m_C. p, then, is the probability that a random selection of M well pads has a lower emission detection result than the M well pads belonging to company X. Therefore, p values near zero and one, respectively, mean that company X has a lower or higher result than the entire dataset, respectively. We use a threshold of 95% to define statistical significance for this analysis, so p less than 0.05 represents statistically significantly better performance for company X, while p greater than 0.95 implies statistically significantly poorer performance, while any p between 0.05 and 0.95 is not strong evidence either way.

Results

Controlled propane releases

The ability of the aerial survey crew to clearly detect the controlled propane plumes was not dependent on the emission rate. The 5.04 g s^{-1} plume was less consistently visible than the 1.89 g s^{-1} plume, in spite of being more than twice as large, perhaps because of the difference in helicopter height (75 versus 50 m) or the difference in meteorological conditions (more complete snow cover for the 1.89 g s^{-1} plume). The 3.49 g s^{-1} plume was the most clearly detectable from the helicopter. All of the propane plumes were clearly detectable with the ground camera (at a distance of 50 m) for all of the propane releases, including a plume generated at 0.14 g s^{-1} for the ground camera only.

Ravikumar et al. (2018) found median detection limits for a GF320 camera of 0.005, 0.014, 0.036, and 0.042 g s^{-1} of methane at measurement distances of 6, 9, 12, and 15 m, respectively, in a summertime ground-based field study in Colorado. Extrapolating their data to a distance of 50 m, we calculate an expected median detection limit of 0.20 g s^{-1} of methane. Optical gas imaging cameras are 3.4 times more sensitive to propane than to methane (Providence, 2019), so we estimate the Ravikumar et al. (2018) 50 m detection limit for propane to be 0.06 g s^{-1}, in the same range as the 0.14 g s^{-1} lowest release rate in this study.

These tests showed that the detection limit for the ground-based camera was at least ten times better than that for the aerial camera, even though we used the same model of camera in both cases. The reason for this difference was likely because the ground-based camera was mounted on a stationary tripod and operated in high sensitivity mode, while the helicopter-based camera could only operate in auto mode because of its constant movement. The background behind the plume was the ground for both cameras, and the distance from the plume was similar. Table S-1 provides detailed information about each propane release, and optical gas imaging videos of propane releases are also available (see data accessibility statement).

Survey overview

Of the 3,428 oil and gas facilities in the aerial survey, the survey crew only detected emission plumes at 16 (0.5%), all of which were producing oil and gas well pads (they surveyed 3,225 producing well pads). In contrast, emissions were detectable at 129 of the 419 well pads visited during the winter and spring ground surveys (31%). A total of 198 emission plumes, or 0.47 plumes per pad, were observed in the ground surveys (some pads had none, and others had multiple detected emission plumes). Example videos are available (see data accessibility statement).

The aerial crew surveyed wells belonging to twenty companies, but only eleven of those companies had wells included in the ground survey. The ground survey included every well at which the aerial crew detected emissions. Seven out of these eleven companies responded to our request for information about observations in the aerial and ground surveys. Of the four that did not respond, two had recently sold their assets in the Uinta Basin to another party, but the new ownership information was not available at the time of the survey. We received responses for 81% of the well pads at which we observed emissions in the aerial survey and 90% of the well pads at which we observed emissions in the ground survey.

Impacts of meteorology, background, and distance

Aerial survey

Average conditions were calm, cold, and clear during the aerial survey, with daytime wind speed of 1.4 (1.2, 1.5) m s^{-1}, daytime temperature of –2.6 (–4.6, –0.6)°C, and skies that were reported as clear for 92 (85, 97)% of daytime hours on survey days. Wind speeds ranged between 0 and 4.0 m s^{-1}. Daytime average temperatures varied between –9.1 and 2.6°C. Average hourly visibility was greater than 10 km on all survey days. Average snow cover was 0.5 (0.0, 1.5)% in surveyed areas on survey days, and ranged between 0 and 8%. The number of emission plumes detected per pad on each aerial survey day was not correlated with daily meteorological conditions.

Ground surveys

We conducted the winter ground survey on the same days as the aerial survey, so the conditions were the same for both surveys. During the spring ground survey, wind speed at survey locations, temperature at survey locations, and percent of survey locations where it was reported to be sunny were 3.0 (2.8, 3.2) m s^{-1}, 18.0 (17.4, 18.7)°C, and 70%, respectively. No snow cover existed during the spring ground survey.

In the ground survey, fewer emission plumes were detected per pad at lower temperatures (**Figure 1**), though the large confidence intervals show that they dataset is noisy and the trend is not statistically significant. Cold ambient temperature leads to poorer contrast between the plume and the background (Ravikumar et al., 2016). Fox et al. (2017) and Fox et al. (2019) discussed the problem of poor optical gas imaging detection during winter months due to cold temperatures. More plumes were detected per pad at the lowest wind speeds, likely because of decreased plume dilution (Ravikumar and Brandt, 2017), though this trend was inconsistent across the range of observed wind speeds.

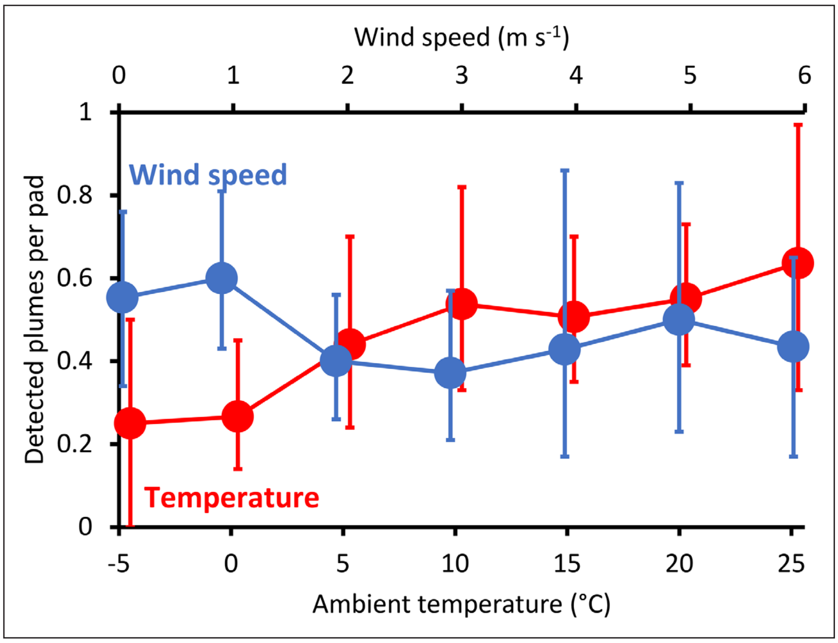

Figure 1: Average number of detected plumes per pad in the ground survey, binned by wind speed and temperature. Temperature was binned in 5°C increments, and wind speed was binned in increments of 1 m s^{-1}. Whiskers show 90% confidence intervals. DOI: https://doi.org/10.1525/elementa.381.f1

Sunny conditions in the ground survey yielded more detected emissions than cloudy conditions (0.63 (0.50, 0.76) and 0.41 (0.27, 0.58) plumes detected per pad in sunny and cloudy conditions, respectively). Sunny conditions allow for more surface heating, creating better contrast between the plume and the background if the ground is used as a background. Clear sky conditions also provide better contrast if the sky is used as a background (Ravikumar et al., 2016). No statistically significant differences in plume detection existed for different backgrounds behind plumes.

It is possible that we detected fewer emission plumes during colder and/or cloudier conditions because of differences in well pad operations that led to fewer actual plumes under these conditions, rather than because of differences in camera detection. There was, however, no correlation of oil or gas production rates with ambient temperature or cloudiness at the wells we visited (maximum r^2 was 0.05), and no relationship between oil or gas production rates and season ($r^2 = 0.01$, $p = 0.79$ for oil; $r^2 = 0.12$, $p = 0.26$ for gas; calculated from average monthly production data for all Utah wells between 2015 and February 2018).

The fraction of well pads with no observable emissions in the ground survey increased from 41% to 76% as the observation distance increased from 16 m to over 100 m, and the fraction of small and medium plumes decreased. All plumes detected at distances over 100 m were in the large-size class. Detection limits have been shown to be related to observation distance in other studies (Ravikumar et al., 2016).

Sources of observed emissions

Aerial survey

All but one of the 16 detected emission plumes in the aerial survey originated from liquid storage tanks. At five of the pads, detected emissions were due to intermittent activities, including liquids unloading and activities related to a well workover. Repairs that operators reported in response to the aerial survey were routine tasks, including closing valves or hatches and making adjustments to control devices. About two months after the aerial survey, the ground survey crew visited all but one of the pads at which the aerial survey detected emissions, and they observed emissions at 13 of 15 pads visited, including all the pads at which repairs were reported. Of the 11 pads at which detected emissions were not due to liquids unloading or maintenance activities, six showed the same source of emissions in both the aerial and ground surveys. Table S-2 presents details about each well pad at which the crew detected emissions in the aerial survey, including findings from the follow-up ground survey at the same pads.

Ground survey

Table 2 shows emission sources at the well pads where emission plumes were detected. For the entire dataset, thief hatches, pressure relief valves and tank vent pipes comprised the majority of emission sources (75.9% of all observed plumes), with emissions of all three qualitative sizes detected. Official inventories show that liquid storage tanks are important sources of hydrocarbon emissions (Pétron et al., 2014), and component-level studies have highlighted tank emissions as significant (Brantley et al., 2015; Hendler et al., 2009).

Pads with emission controls on tanks had a similar source distribution to the entire dataset (i.e., most emissions were not from the control devices themselves, but from tank hatches, vents, or piping upstream of the control devices), but they tended to have a larger percentage of plumes qualitatively categorized as large, perhaps because pads with controlled tanks tend to have higher production rates (see discussion below).

Companies reported that they made repairs in response to this study at 56 well pads (43% of all pads with observed emissions). At 34% of the pads for which we received responses, companies indicated that observed emissions

Table 2: Sources and qualitative sizes of observed emissions for the entire dataset and well pads with emissions controls on tanks. S, M, and L indicate emission plumes that were qualitatively categorized as small, medium, and large, respectively. DOI: https://doi.org/10.1525/elementa.381.t2

	Entire ground survey dataset					Pads with controlled tanks				
	S	M	L	TOTAL	%	S	M	L	TOTAL	%
Thief hatch	19	27	13	59	30.3%	3	11	11	25	26.6%
Pressure relief valve	24	18	13	55	28.2%	13	9	10	32	34.0%
Tank vent pipe	18	7	9	34	17.4%	4	5	8	17	18.1%
Combustor	3	1	2	6	3.1%	3	1	2	6	6.4%
Flare stack	1	5	1	7	3.6%	0	2	1	3	3.2%
Unidentified source	2	2	0	4	2.1%	1	2	0	3	3.2%
Underground pipe	0	1	0	1	0.5%	0	0	0	0	0.0%
Dehydrator	4	13	3	20	10.3%	1	3	2	6	6.4%
Chemical pump	0	1	0	1	0.5%	0	0	0	0	0.0%
Well head	4	1	3	9	4.6%	2	0	0	2	2.1%
TOTAL	75	76	44	195	100.0%	27	33	34	94	100.0%

from tanks were part of normal operations (i.e., the tanks were uncontrolled), and thus repairs were not needed. Operators completed repairs within 43 (34, 52) days of the ground survey date. **Table 3** shows repair categories, the number of repairs made, and costs incurred for repairs.

Results by company

Table 4 provides anonymized company-level information about the results of the aerial and ground surveys. The frequency and average qualitative size (i.e., severity score) of detected emission plumes varied widely among companies whose well pads we surveyed in this study. All operators that responded to the survey reported that they had a leak detection and repair program for well pads in the Uinta Basin, but no clear relationship existed between inspection frequency and plume detection frequency or severity in **Table 4**.

Pads with emissions controls on tanks had a higher number of detected plumes per pad and a worse severity score than the entire dataset, and these differences were statistically significant (Monte Carlo test; see methods for more information). This shows that well pads with emission controls on tanks are more likely to (1) have detectable emissions from tanks and (2) have qualitatively larger emission plumes than the dataset as a whole. We discuss possible reasons for this below.

Well pad properties

Table 5 shows a comparison of the properties of all surveyed producing well pads and the pads at which we detected emissions. Compared to the entire population of surveyed pads, pads with detected emissions were higher-producing (as shown by Brantley et al. (2015)), were younger (as shown by Lyon et al. (2016)), and had more tanks per pad.

Table 3: Number and cost of repairs reported by operators. DOI: https://doi.org/10.1525/elementa.381.t3

Repair category	Number of repairs made	Cost of repairs
Hatch maintenance	26	$308 ($199, $446)
Piping repair	8	$127 ($28, $238)
Combustor maintenance	7	$119 ($43, $241)
Pressure relief valve repair	7	No data
Hatch replacement	6	$3,872 ($2,829, $5,046)
Regulator replacement	1	No data

Table 4: Average frequency and qualitative severity of detected emission plumes by company. DOI: https://doi.org/10.1525/elementa.381.t4

Company	Pads surveyed	LDAR frequency	Entire ground survey dataset		Pads with controlled tanks	
			Plumes per pad	Severity score	Plumes per pad	Severity score
A	16	No data	0.63	2.5	0.83	2.4
B	121	Semiannual/none	0.41	*2.2*	**0.44**	*2.4*
C	58	No data	–	–	–	–
D	21	No data	0.31	2.3	0.36	2.3
E	227	None	*0.91*	1.9	*1.47*	2.0
F	474	Semiannual	**0.30**	**1.6**	**0.13**	1.0
G	581	Annual	*0.66*	1.7	1.43	1.8
H	755	Annual/monthly	**0.20**	2.0	**0.25**	2.3
I	7	No data	0.25	2.0	0.33	2.0
J	65	Semiannual	1.00	2.0	1.00	2.0
K	248	No data	**0.17**	**1.0**	**0.00**	**0.0**
L	75	No data	1.00	1.0	1.00	1.0
Average			0.47	1.8	*0.72*	*1.9*

Values in bold indicate that the company's performance for a given metric is better than the group, as determined by a Monte Carlo analysis of statistical significance, and values in italic indicate that a company underperformed the group. LDAR (leak detection and repair) frequency is also shown and indicates the frequency at which companies reported they inspect for leaks at the well pads in the survey.

Table 5: Comparison of properties of well pads at which we detected emissions versus the entire surveyed population. DOI: https://doi.org/10.1525/elementa.381.t5

Well pad property	Aerial survey		Winter and spring ground surveys	
	Entire population	Emissions detected	Entire population	Emissions detected
% that were oil well pads	41.6%	75.0%	63.7%	62.8%
Avg. oil production (bbl day^{-1})	7 (6, 7)	41 (22, 81)	12 (10, 17)	18 (13, 32)
Avg. gas production (MCF day^{-1})	100 (92, 109)	162 (104, 285)	84 (63, 124)	94 (62, 213)
Avg. pad age (months)	159 (155, 163)	107 (61, 188)	154 (142, 167)	142 (123, 165)
Avg. wells per pad	1.4 (1.4, 1.4)	1.6 (1.1, 2.3)	1.3 (1.2, 1.4)	1.3 (1.2, 1.5)
% with glycol dehydrators[a]	14.2%	22.2%	26.5%	14.3%
% with emission controls on tanks[a]	13.3%	55.6%	26.5%	40.0%
Avg. number of tanks per pad[a]	2.6 (2.5, 2.8)	4.7 (2.3, 10.9)	2.4 (2.3, 2.6)	3.2 (3.0, 3.5)

[a] Indicates data derived from the 2014 Utah air agencies oil and gas emissions inventory (UDAQ, 2018b). Well pads constructed after 2014 are excluded from the analyses of 2014 inventory data.

In the population of well pads included in the aerial survey, per-pad production of barrels of oil equivalent (bbl day^{-1} of oil + MCF day^{-1} of gas/5.8) was not correlated with pad age (p = 0.28) when production was binned by pad age at 24-month intervals (n = 22). When binned in the same way, however, being an oil well pad (oil well pads were given a value of 1 and gas well pads a value of 0) was weakly negatively correlated with pad age (r^2 = 0.15; p = 0.08), probably because recent commodity prices have made oil production more cost-competitive than gas production. Oil well pads had more tanks per pad than gas well pads (4.1 (3.8, 4.3) versus 2.1 (2.0, 2.2)), and this could be one factor that explains the higher detection rate at oil well pads in the aerial survey.

Higher-producing pads may have more detectable emissions because equipment, including liquid storage tanks, is subject to higher throughput and higher pressures at these pads relative to lower-producing pads. Using the same age-binned dataset, the number of emission plumes detected per pad in the aerial survey was weakly correlated with pad age (r^2 = 0.17; p = 0.06), production of barrels of oil equivalent (r^2 = 0.22; p < 0.03), and with being an oil well pad (r^2 = 0.19; p = 0.05). Having tank emissions controls was correlated with production of barrels of oil equivalent (r^2 = 0.31; p = 0.01), which could explain why pads with tank emissions controls were more likely to have detected emissions (see previous section).

While the ground survey and the aerial survey showed similar trends, the differences between the entire surveyed population and the pads with detected emissions were smaller in the ground survey than in the aerial survey. We expect that this was due to the large difference in the minimum detectable emission rates between the aerial and ground surveys. Only very large emission plumes were detectable in the aerial survey, so differences between pads with detectable plumes and all surveyed pads were more pronounced. Well pads with qualitatively large plumes in the ground survey had more oil production than well pads with plumes categorized as medium and small (31 (17, 80) versus 13 (9, 20) bbl day^{-1} pad^{-1}). The same was true for gas production (178 (74, 587) versus 59 (46, 82) MCF day^{-1} pad^{-1}).

Survey costs

Table 6 shows a cost breakdown for the aerial and ground surveys (the aerial survey also included about $10,000 in mobilization and demobilization costs that are excluded from **Table 6** because mobilization costs can be expected to vary depending on the origin and destination of the helicopter). The aerial survey was able to visit more well pads in a much shorter period, so the cost per facility surveyed was lower for the aerial survey than for the ground survey. The poorer detection limit of the aerial survey led to a much higher cost per detected emission plume, however. Since we expect detection limits for the aerial survey to be better in summer, **Table 6** also shows the cost per detection with the assumption of a 6.6% detection rate, which was the rate during the summertime Lyon et al. (2016) study.

Schwietzke et al. (2018) compared the cost per methane emissions avoided for ground optical gas imaging versus two different aerial emissions detection methods. When Schwietzke et al. assumed all aerial emissions detected were repairable, except cases of methane slip and maintenance events, they found that their ground-based survey was much more expensive per amount of methane reduced than the two aerial detection methods used. Since we made no attempt to quantify emissions, our study is not directly comparable with Schwietzke et al. We expect that the emission plumes detected in the aerial survey were, on average, much larger than in the ground survey, so if we were able to calculate cost per mass of hydrocarbon emissions reduced, rather than the cost per emission plume detected, **Table 6** might look very different, and our findings might be more similar to those of Schwietzke et al. Companies that responded to our requests for information

Table 6: Aerial and ground survey costs. DOI: https://doi.org/10.1525/elementa.381.t6

	Aerial survey	Ground survey
Survey cost	$75,000	$21,000
Survey days	10	24
Facilities surveyed	3,428	417
Facilities surveyed with detected emissions	16	129
Facilities surveyed per day	343	17
Survey cost per day	$7,500	$900
Cost per facility surveyed	$22	$50
Cost per facility with detected emissions	$4,690	$160
Cost per facility with detected emissions (assuming Lyon et al. (2016) detection rate)	$330	–

indicated that 31% of pads with detected emissions in the aerial survey and 34% of pads with detected emissions in the ground survey were not repairable (i.e., they were part of normal operations), so accounting for repairability would not meaningfully change the cost comparison of the aerial and ground surveys.

Our ground survey method was very different from Schwietzke et al. (2018), which may also have caused some of the difference between the two studies. Because we conducted our survey from the edge of the pad, and because we did not attempt to quantify emission rates, we were able to visit 2.1 facilities per hour, while the Schwietzke et al. ground crew was able to visit only 1.0 facilities per hour. Also, we used the same source(ICF, 2016) to calculate a total hourly cost (labor, mileage, and equipment) of only $107, compared to their $142, since our survey did not include the cost of any leak quantification equipment.

Comparison with other Uintah Basin surveys

Comparison with Mansfield et al

The ground-based portion of our study and the Mansfield et al. (2017) ground survey of oil well pads with control devices on tanks both showed that a high percentage of pads with tank controls have detectable emissions (47 versus 40%, respectively) and that most emissions were from liquid storage tanks (75.9 versus 82.6%). Both studies also showed an increased likelihood of detected emissions and emission plumes categorized as large from pads with higher oil and gas production. In controlled propane releases conducted by Mansfield et al., the emission plume was not consistently detectable from a 50 m distance at 0.3 g s^{-1}, whereas in this work we could clearly detect a propane emission of 0.14 g s^{-1}. The propane source was identical in both studies, but Mansfield et al. used an OpGal EyeCGas camera, rather than the FLIR GF320 camera used in this work.

Well pads owned by some of the companies shown in **Table 4** were also surveyed by Mansfield et al. (2017), and we surveyed 53 of those pads in the current study. Comparing pads with controlled tanks in this study to the Mansfield et al. results, companies A and E increased from 0.27 to 0.83 and 0.55 to 1.47 plumes per pad, respectively, over the 1.5 years between the two studies. Company F improved, changing from 0.60 to 0.13 plumes per pad and from a severity score of 2.2 to 1.0. Companies B and D were similar in both studies. We compared the average pad age and oil production rates for the pads with controlled tanks in this study to the Mansfield et al. results, but we did not find any consistent relationships between these parameters and changes in plume size or detection rates.

While the data we collected are insufficient to determine with certainty the causes of changes (or lack of changes) in company performance, we did receive information from company F about changes to operations that could have led to the observed decrease in detected plumes at their well pads. After the Mansfield et al. survey, company F installed new equipment and implemented operational practices at facilities with storage tank controls. The new equipment included tank thief hatches and gaskets that are designed to be leak free. The company also installed new pressure relief devices on tank control systems that were set to release at a lower pressure than tank thief hatches. This minimized the number of vent/leak sources (i.e., a single pressure relief device, as opposed to several tank thief hatches venting) and helped maintain the integrity of the tank thief hatch and gaskets. Also, the company implemented both audio, visual, and olfactory (AVO) surveys and leak detection and repair (LDAR) surveys to help assure that these devices were operating properly. These changes could be the cause of improved performance by company F in the current study relative to the Mansfield et al. study. We do not have information about whether other companies made similar changes after the Mansfield et al. study.

Comparison with Lyon et al

Emission plumes were detected at a much lower percentage of oil and gas facilities in the aerial portion of the current study (0.5%) relative to the Uinta Basin portion of the study performed by Lyon et al. (2016) (6.6%). Both aerial surveys were conducted by the same company with the same camera and camera operator, with the same camera settings, and the helicopter flew at the same height above ground in both studies.

Englander et al. (2018) returned to the Bakken oil field in North Dakota and conducted an aerial infrared camera survey one year after the survey conducted there by Lyon et al. (2016) Both surveys were conducted in September. For pads that were surveyed in both years, Englander et al. found a similar percentage of detected emissions (11.1% versus 10.8%). Further, they showed that pads with detected emissions in the first study were likely to be emitting in the second study. We, on the other hand, did not detect emissions at any of the 652 pads in our survey that were also part of the Lyon et al. survey, even though Lyon et al. detected emissions at 47 (7%) of those pads. Unlike the Englander et al. study, our study occurred four years after the original Lyon et al. study, allowing for significant changes in the industry to occur. Also, our study occurred in a different season (February-March versus July), resulting in poorer detection limits.

The surveyed well pad population in this study was 34% older, produced 34% less oil, and produced 26% less of its energy from oil (determined using the method presented by Lyon et al. (2016)) relative to the survey conducted by Lyon et al. All of these well pad properties were associated in both studies with a decreased likelihood of emissions that were detectable from the helicopter. Also, industry practices and regulations are changing, which could lead to lower per-pad emissions (EPA, 2018; Lamb et al., 2015; UDAQ, 2018a).

Wind speed (1.4 (1.2, 1.5) versus 1.5 (1.2, 1.9) m s^{-1}, respectively) and cloudiness (clear skies 92 (85, 97) versus 89 (70, 95)% of survey hours) were similar during this study and the Uinta Basin portion of the Lyon et al. study. Snow cover was not present when the Lyon et al. study was conducted but was very low during this study as well. The most significant meteorological difference between the two studies was temperature (–2.6 (–4.6, –0.6) versus 21.4 (20.6, 22.4)°C in this study and Lyon et al., respectively).

Lower temperature and decreased solar insolation are associated with poorer detection by infrared optical gas imaging cameras (Ravikumar and Brandt, 2017; Ravikumar et al., 2016), and this could account for much of the difference in detection between the two studies. We used the Ravikumar model of plume detectability to explore the extent to which meteorological conditions may have impacted the results of the two studies. For the aerial survey, the background behind the plume was always the ground, so the detection limit was determined by the contrast between the apparent plume temperature (a measure of the amount of infrared energy emitted by and reflected from the plume in the camera's bandwidth of 3.2 to 3.4 μm) and the apparent ground temperature.

Figure 2 shows the relationship between the modeled minimum methane detection limits of the infrared camera and the apparent temperature difference for the meteorological conditions of the two studies. Since we did not record the apparent ground temperature during the studies, it is impossible to know the actual detection limits with certainty. Typically, summers experience higher differences in apparent temperature compared to winter due to higher solar insolation. If we assume an apparent temperature difference of 20°C in the summer (Lyon et al.) and 10°C in the winter (this study), the minimum detection limits during this study would be higher than those experienced by Lyon et al. in the summer by 3–4 times, which explains at least a portion of the observed lower plume detection rate in this study compared Lyon et al.

Controlled hydrocarbon releases provide another way to compare detection limits in the two studies. In this study, the propane plume was marginally detectable somewhere between 1.89 and 5.04 g s^{-1}. Lyon et al. (2016) reported that a methane emission plume of 3 g s^{-1} was marginally detectable. Since infrared camera detection limits for propane are 3.4 times lower (i.e., better) than for methane, we can assume a methane detection limit in our study in the range of 6 to 17 g s^{-1}, between 2.1 and 5.7 times worse than the detection limits reported by Lyon et al.

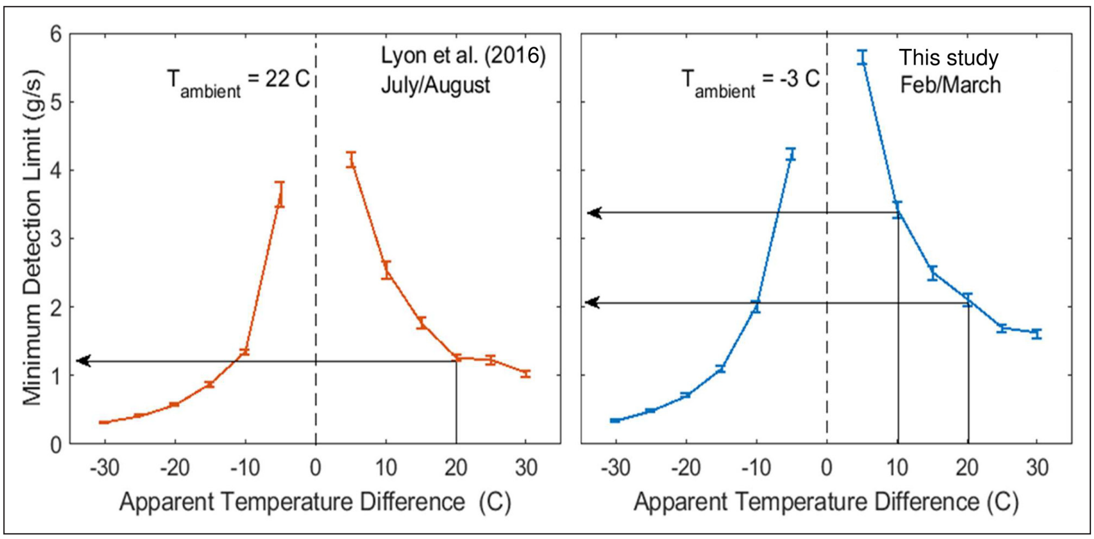

Figure 2: Relationship between apparent temperature difference between plume and ground and the minimum detection limit for methane. Values were calculated using the Ravikumar model. DOI: https://doi.org/10.1525/elementa.381.f2

Implications

This study has two main implications. First, because optical gas imaging cameras perform relatively poorly in winter, oil and gas facilities at which they are used for leak detection likely have higher overall leak rates in winter compared to summer (since it is likely that more leaks go undetected, and therefore unrepaired, in winter). Use of alternative detection techniques that are not affected by temperature (e.g., handheld natural gas detectors) as a supplement to optical gas imaging may improve wintertime leak detection and repair programs. Though our ground survey was conducted further from potential emission sources than typical on-pad leak detection programs, modeling studies have shown that low temperature likely impacts optical gas imaging detection generally (Fox et al., 2017; Ravikumar et al., 2016).

Secondly, systems to control emissions from liquid storage tanks often do not achieve their intended purpose. We only rarely observed emissions from combustors or vapor recovery units, but we frequently observed emissions from tank infrastructure upstream of these control devices, indicating that a portion of gas in storage tanks escaped before reaching control devices. Our finding that pads with tank emission controls were more likely to have detected emission plumes than the overall study population implies that malfunctioning tank emission control systems are very common. The U.S. EPA released a compliance alert that discusses this problem and its potential causes, which include (1) pressure and/or flow within tanks and associated valves and piping that exceeds the equipment's capacity, (2) accumulation of liquids that block gas flow in piping, and (3) malfunctioning or improperly maintained pressure relief devices (EPA, 2015). Changes to design and maintenance practices may lead to a reduction in lost gas from emission control systems.

Supplemental files

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

- **Table S-1.** Information about controlled propane releases conducted to determine detectable emission rates. (Page 2). DOI: https://doi.org/10.1525/elementa.381.s1
- **Table S-2.** Information about each well pad at which emissions were detected in the aerial survey. Size is a qualitative determination made by the camera operator. (Page 3). DOI: https://doi.org/10.1525/elementa.381.s1
- **Supplemental material.** Example survey videos and anonymized datasets. DOI: https://doi.org/10.1525/elementa.381.s2

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Competing interests

The authors have no competing interests to declare.

Author contributions

All authors contributed to study conception, design, and article drafting and revisions. MLM conducted the Monte Carlo analysis. APR carried out the detection limit modeling. TT and SNL led other data analyses with contributions from the other authors.

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