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Article

Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data

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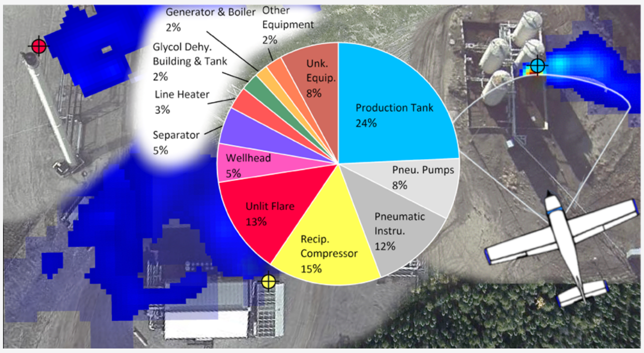
ABSTRACT: Airborne LiDAR measurements, parallel controlled releases, and on-site optical gas imaging (OGI) survey and pneumatic device count data from 1 year prior, were combined to derive a new measurement-based methane inventory for oil and gas facilities in British Columbia, Canada. Results reveal a surprising distinction in the higher magnitudes, different types, and smaller number of sources seen by the plane versus OGI. Combined data suggest methane emissions are 1.6–2.2 times current federal inventory estimates. More importantly, analysis of high-resolution geo-located aerial imagery, facility schematics, and equipment counts allowed attribution to major source types revealing key drivers of this difference. More than half of emissions were attributed to three main sources: tanks (24%), reciprocating compressors (15%), and unlit flares (13%). These are the sources driving upstream oil and gas methane emissions, and specifically, where emerging regulations must focus to achieve meaningful reductions. Pneumatics accounted for 20%, but this contribution is lower than recent Canadian and U.S. inventory estimates, possibly reflecting a growing shift toward more low- and zero-emitting devices. The stark difference in the aerial and OGI results indicates key gaps in current inventories and suggests that policy and regulations relying on OGI surveys alone may risk missing a significant portion of emissions.



KEYWORDS: *venting, fugitive emissions, aerial, OGI, top-down/bottom-up, tanks, compressors, flares*

INTRODUCTION

The oil and gas sector is a dominant source of anthropogenic methane emissions, and several recent studies suggest that its contribution to current inventories is underestimated.[1−4] Because of methane's strong global warming potential and short atmospheric lifetime relative to carbon dioxide,[5,6] immediate reduction of methane emissions is seen as essential to holding planetary warming below a 2 °C threshold.[7] Reduction of oil and gas sector methane emissions depends on accurate understanding of the frequency, distribution, and magnitudes of different source types. Many independent field studies have demonstrated that source distributions are generally highly skewed, where a small proportion or sources or sites is responsible for a majority of emissions.[8−11] This continues to confound current emission inventories based on simple emission factors scaled with production data.

Using a range of approaches applied in a variety of regions, field studies have repeatedly found that measured methane emissions significantly exceed inventory predictions, often by 50% or more.[2−4,12] So-called "fugitive emissions" from leaking components are often implicated as an important factor in this discrepancy, and most newer methane regulations mandate periodic inspections for leaking equipment, typically via optical gas imaging (OGI) cameras. However, recent studies have shown that the OGI may not be as effective as originally thought.[13,14] Moreover, at least in some jurisdictions, confusion and inconsistency about the definitions of fugitive vs vented sources, and the inherent difficulty in using qualitative OGI to distinguish normal and abnormal venting from key components such a pneumatic equipment and storage tanks, can further hamper the effectiveness of OGI in practice. Recent repeated OGI surveys of facilities in Alberta, Canada, found that "leaks" only comprised 15% of total methane emissions when storage tanks were classified as vents, with the latter comprising almost 2/3 of total emissions.[15] Because current policy and regulation have been developed using insights based on current inventories, these issues have serious consequences for the effectiveness of regulations and the likelihood of meeting methane reduction targets.

This paper combines aerial methane measurements using Bridger Photonics Inc.'s novel Gas Mapping LiDAR

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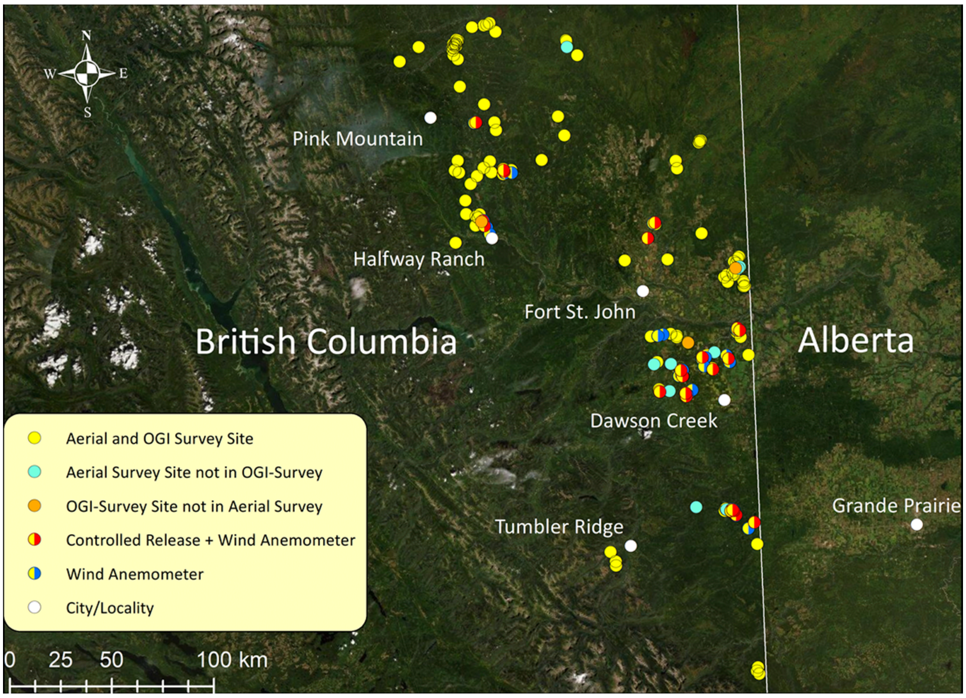

Figure 1. Geographic locations of 167 aerial survey sites in Northern British Columbia Canada with 29 fully blinded controlled releases (half red dot) and 65 on-site wind measurements from flights and repeat flights at 48 unique sites.

(GML),[16,17] parallel controlled release data to quantify GML sensitivities and uncertainties,[18] separate on-site OGI survey and major equipment count data completed 1 year prior,[19] and detailed analysis of facility schematics and aerial imagery to derive true distributions and breakdown of methane sources at upstream oil and gas production sites. Measurements were completed in British Columbia, Canada, which was an ideal study region given the unique wealth of data available for the present analysis including extensive on-site component count and OGI survey data, detailed facility plot plans, production accounting data, and national inventory data for comparison as outlined below. As a province, BC produced approximately 35% of Canada's natural gas in 2020,[20] which as a nation is the fourth largest producer of natural gas in the world.[21] BC is also poised for rapid growth as producer and global exporter of liquified natural gas via the LNG Canada terminal currently under construction.[22] Most importantly however, the mix of facility types in BC, and specifically the types of major equipment within these upstream production sites (including storage tanks, compressors, flares, pneumatic equipment, wellheads, etc.), are common throughout the world as reflected in recent international policy statements and recommendations for mitigation.[23−25]

The key objectives of this analysis were to use the combined data in conjunction with high-resolution aerial imagery and facility plot plans provided by the BC Oil and Gas Commission (BCOGC) to identify major sources in the aerial survey data; to contrast types, distributions, and magnitudes of sources seen in aerial vs OGI surveys; and ultimately to derive an updated, measurement-based methane inventory for upstream oil and gas production sites to compare with current inventory estimates. The comprehensive analysis provides fresh insight into the true distribution of methane sources that, for the first time, gives direct insight into the reasons for significant discrepancies with bottom-up inventory estimates. These results have further implications for the efficiency and likely effectiveness of emerging methane regulations.

METHODOLOGY

Under the direction of the BC Oil and Gas Methane Emissions Research Collaborative (MERC), an aerial survey of oil and gas sites in Northern British Columbia was completed using the Bridger Photonics Gas Mapping LiDAR (GML) technology in September 2019. The selected sites included oil and gas production and processing infrastructure ranging in size and complexity from isolated off-site well locations (one or more wellheads with minimal on-site equipment connected by pipeline to a proration battery at a separate location) and single-well batteries (1−2 tanks, separators, and potentially a flare), to larger multiwell batteries and gas plants with multiple tanks, compressors, dehydrators, combustion sources, flaring infrastructure, and associated production equipment. In total, the aerial survey covered 167 geographically distinct sites comprising 105 wells within 80 off-site well locations, 72 batteries (including an additional 110 on-site wells), 8 gas plants, 4 compressor stations, and 3 other/unidentified facilities. Among active facilities in 2019, this sample represented 15% of single-well batteries, 16% of multiwell batteries, 13% of gas plants, and 1% of off-site wells, which together accounted for 96% of upstream oil and gas sector methane emissions in the updated inventory (see Supporting Information, SI, Figure S5).

Most of these same sites were included in a comprehensive ground survey performed 1 year prior by Cap-Op Energy (now Radicle), that included OGI detection of sources, quantification (where possible) using a Hi Flow sampler, and manual counting of major on-site process equipment and pneumatic devices.[19] These OGI survey sites were originally selected in a "quasi-random process" that balanced geography, site access, and statistical randomness to be representative of British

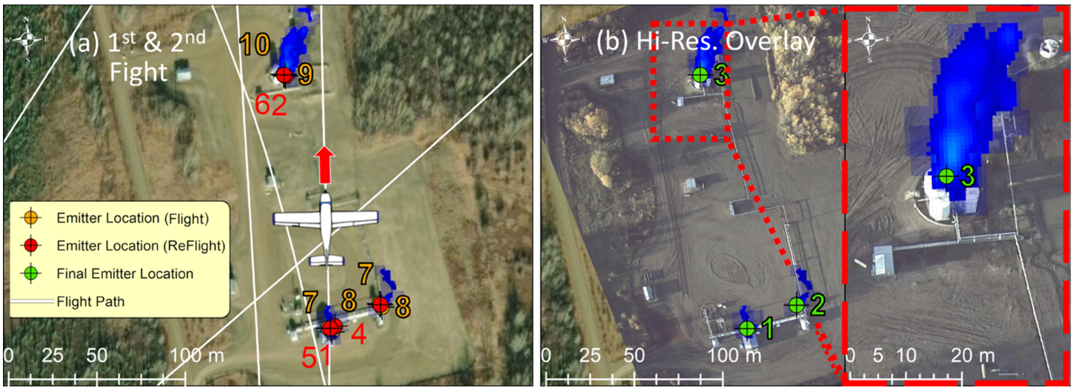

Figure 2. Interpretation of Bridger GML detection data. (a) Numbered detections from all five flight passes (white lines) over two consecutive days. Orange numbers show detection from initial flight, and red numbers show detections on the reflight 1 day later. Indicated plumes (blue) are shown for the reflight. (b) Using ArcGIS, high-resolution aerial photo from the plane is manually mapped to available satellite imagery from (a) using multiple control points. Georeferenced plume data are overlaid along with final synthesized source detections from all flight passes. Zoomed image indicates resolution in identifying major equipment sources, in this case a liquid storage tank.

Columbia's upstream oil and gas sector in by facility type.[19] The aerial survey was augmented to include several additional multiwell batteries as well as gas plants identified as having reported 10 000 tonnes or more of carbon dioxide equivalent (CO_2e) per year under British Columbia's Greenhouse Gas Industrial Reporting and Control Act.[26] Figure 1 shows a map of sites included in both surveys.

A critical part of the aerial data analysis leveraged parallel fully blinded, in situ controlled methane release experiments to quantify the lower sensitivity limit and measurement uncertainties of the Bridger GML technology.[18] Concurrent with the aerial measurements, a ground team from Carleton University's Energy & Emissions Research Lab (EERL) visited 48 unique sites (Figure 1), completing 65 wind on-site measurements and 29 fully blinded controlled methane releases. These data helped establish the true, in-field detection limits of the GML technology as a function of wind speed and were critical in subsequent interpretation of results and combined analysis of aerial measurement and ground survey data. These data were also used to estimate uncertainties as part of a Monte Carlo analysis detailed in Section S4 in the Supporting Information (SI).

Combining results of these two surveys and controlled releases enabled the main focus of the paper—determining a measurement-based estimate of the true breakdown of methane sources at upstream oil and gas production sites and creating updated inventory estimates based on these new data. As explained below, high-resolution aerial photographs, satellite imagery, manual count data from on-site surveys, and facility schematics provided by BC Oil and Gas Commission (BCOGC) were used to identify key major sources of detected emissions and investigate reasons for discrepancies among different measurement approaches and inventories. Finally, the contrasting aerial and ground survey data, interpreted in the context of field-determined sensitivity limits, were then used to create a revised inventory estimate of upstream oil and gas sector methane emissions in the province.

Interpreting Bridger Emission Rate Data. The Bridger GML technology enabled detection of individual methane plumes within facilities at a resolution of ~2 m with detection sensitivities as low as 0.6 kg/h depending on on-site wind conditions[18] as further considered below. For each site in the aerial survey, the airplane made one or more passes to scan on-site infrastructure. Sites with detected emissions were flown a second time on a subsequent day (again with one or more passes as required to fully cover the site) to collect an additional set of measurements under potentially different local wind and on-site production conditions, providing a measure of the emission rate variability and persistence. The plane flew at a nominal altitude of 230 m above ground which, combined with the sensor field of view of 31°, produced a ~128 m wide LiDAR measurement swath on the ground with a spatial resolution of 2 m.[17] Figure 2 shows an example site from the measurement survey. For each pass, Bridger provided: (i) a detection date/time for any quantifiable sources; (ii) geo-located two-dimensional (2D) plume imagery; (iii) one or more potential source location(s) corresponding to each quantified methane plume; and (iv) a measured emission rate in liters per minute (lpm) of methane (at 15 °C and 101 325 Pascals). Quantification uncertainties were conservatively estimated using the probability density functions derived from controlled releases near the lower sensitivity limit[18] as detailed in the SI. For a single pass of the airplane, 1σ uncertainties were typically ±31−68% depending on whether on-site wind data were available.

As fully explained in the SI, data for individual passes and flights were carefully analyzed to identify a robust and generally conservative set of sources and average emission rates. First, the automated detections were manually reviewed to identify spatially distinct sources and grouped or disaggregated as appropriate. Common sources from different passes (if captured more than once during a flight) were averaged, and sources from each flight were averaged with corresponding sources (whether detected or not) from the subsequent reflight on a different day. Importantly, this means that sources detected during the first flight but not the subsequent flight (or vice versa) were conservatively averaged with a zero, while acknowledging that they could still be emitting below the detection limit. Further conservatism likely arises because actual LiDAR coverage can be diminished by ground cover conditions and standing water which attenuate the return laser intensity. Where possible, flight path and laser swath data (a measure of the laser coverage derived from the laser return signal) were used to verify that identified sources had the potential to be seen among different passes and flights. In three cases where small controlled release plumes (<1.75 kg/h) were

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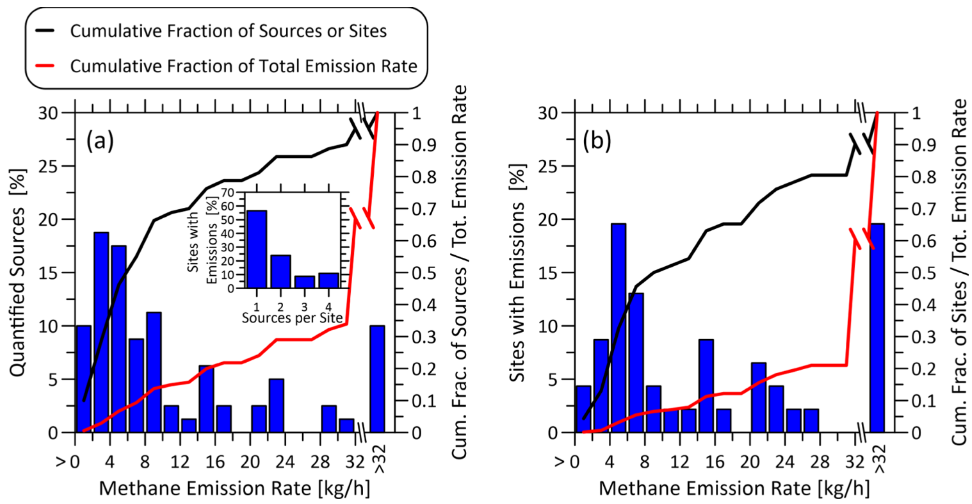

Figure 3. Emission distributions derived from aerial survey data. (a) Distribution of 80 sources at 46 sites totaling 1802 kg/h with average emission rates ranging from 0.5 to 399 kg/h. The frequency of the number of sources per site is shown in the inset. (b) Distribution of emission by site obtained by aggerating sources.

enveloped by larger plumes from on-site sources (5.5−19.1 kg/h), the contribution from the former was subtracted.

Identifying On-Site Emission Sources from Aerial Methane Detections. Beyond simply contrasting aerial and OGI survey detected emissions, an important component of this study was to use the aerial data to identify, where possible, key equipment responsible for detected on-site emissions. For each site, a high-resolution aerial photo taken by the plane during the survey was manually registered to available georeferenced satellite imagery within ArcGIS by assigning control points to common features such as on-site buildings, wellheads, site boundaries, and roads. Georeferenced plume imagery was then overlaid along with final emitter locations, derived from multipass and multiflight survey data (green symbols in Figure 2b). Relative to available satellite imagery alone, this provided an up-to-date site layout from the time of survey and allowed much finer resolution when zooming in to inspect individual sources (see the inset image of emitting tank in Figure 2b). Next, by comparing this high-resolution imagery with detailed site schematics (obtained from the BC Oil and Gas Commission and available for 42 of 46 sites with emissions), on-site major equipment count data from the prior ground survey,[19] photos and logs from the EERL ground team taken while deploying wind sensors and controlled release equipment,[18] it was possible to attribute specific types of major equipment or buildings (e.g., storage and production tanks, compressor buildings, flares, dehydrators, etc.) to individual detected plumes. If site schematics were unavailable for a site, readily identifiable equipment such as tanks, compressors, or flares could still be assigned, but less obvious or ambiguous sources such as a nondescript building were labeled as unknown.

RESULTS AND DISCUSSION

Measured Source and Site Emission Rate Distributions. Twenty-eight percent of sites in the aerial survey had measurable sources of methane, with average source emission rates (over two successive days) ranging from 0.5 to 399 kg/h. The distribution of source rates (Figure 3a) was strongly positively skewed (median of 6.3 kg/h and mean of 22.3 kg/h), where the horizontal axis is necessarily broken to accommodate large sources greater than 32 kg/h. This long-tailed distribution is typical of many oil and gas sector emission studies, where the present Gini coefficient of 0.73 (a measure of disproportionality where a number closer to one indicates stronger influence from a smaller number of large sources)[27] is in the range of studies reviewed by Zavala-Araiza et al.[10] Indeed, 10% of detected sources accounted for 66% of the total emissions and the largest three sources, found at a single site, accounted for 52% of measurable emissions. As shown in the inset histogram of Figure 3a, just over half (57%) of sites with emissions had a single source, while the remainder (representing 12% of all sites in the survey) had up to four measurable sources.

Aggerating sources to sites in Figure 3b shows the distribution of site emission rates is similarly skewed (Gini coefficient of 0.76). Among the 28% of sites with measured emissions, the median and mean site emission rates were 10.2 and 39.2 kg/h, respectively. Nine sites, comprising four gas plants and five multiwell batteries, had site emission rates greater than 32 kg/h and accounted for 79% of the total measured emissions. Interestingly, not all of these sites had multiple emission sources; two sites had single emission sources of 41.5 and 49.1 kg/h, which were attributed to storage tanks as further investigated below. For context, the aerial measurement data alone suggest several sites were emitting well above notional limits in impending federal and provincial regulations as elaborated below. Note however that the aerial measurements were completed in September 2019 and new regulations began a 3 year phase-in in 2020.

Contrast of Source Distributions between the Aerial and Ground Survey. Considering the subset of 140 sites in the aerial survey (comprising 198 wells and 60 batteries) that matched sites in the prior ground survey,[19] it is possible to directly contrast emissions seen by airborne GML versus a conventional OGI survey. Importantly, with the exception of pneumatic equipment which were counted but not measured unless specifically noted to be abnormally operating, the ground survey gathered emission data from both fugitive leaks (e.g., leaking connectors, valves, and other components as well as emissions from controlled tanks) and "vents" (e.g., compressor seals/rod-packing emissions, wellhead surface

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casing vents, and emission from tanks without controls). Detected sources were measured where possible using a Bacharach Hi Flow Sampler[28] (79% of sources) or visually estimated where necessary (e.g., inaccessible heights) at the "discretion of the field team based on safe operating practices".[19]

As shown in Figure 4, the difference between source distributions from the two studies is stark. The total emissions

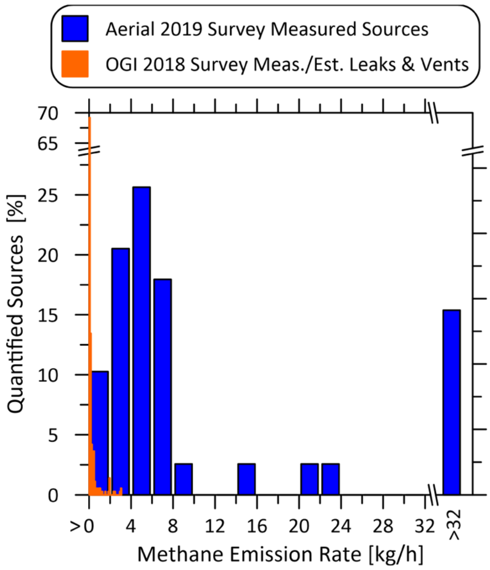

Figure 4. Contrast of source distributions measured in the aerial survey (blue) and prior OGI survey (orange) for the common set of 140 sites (comprising 198 wells and 60 batteries) covered by both surveys.

measured by the aerial survey were 18 times greater than those found during the OGI survey. Even if the largest site in the aerial survey (whose four separate sources summed to 74% of all emissions in this subset of 140 sites) was thought to be anomalous and excluded, the difference was still a factor of ~5 (341 vs 71 kg/h). If anything, lower overall emissions in the aerial survey might have been expected given the 1 year time frame for repairing sources following the OGI survey. Clearly, the opposite is true. It should be added that while a notable recent study has demonstrated the importance of operator experience in OGI detection rate,[13] this should not have been a factor in the OGI surveys completed by Cap-Op.[19] Moreover, the aerial survey found far fewer but much larger sources (39 vs 357 sources). In general, this suggests the two surveys are finding different types of emission sources at the same sites as further explored below. This has profound implications for inventories derived primarily based on OGI data and associated emission factors.

Attribution of Measured Sources to Major Equipment. From the manual inspection of site schematics, imagery, and count data, 95% of sources and 87% of total detected emissions in the aerial survey could be attributed to specific major equipment types. Among fourteen different types of emitting equipment that could be identified, the most frequently detected sources (Figure 5a) were reciprocating compressors followed by production tanks, other equipment (including boilers, power generators, line heaters, etc.), and unlit flares. However, total emissions (Figure 5b) were strongly dominated by production tanks followed by unlit flares and reciprocating compressors, where these top three sources accounted more than three-quarters of total emissions measured by the plane.

By contrast, the prior OGI-based ground survey (Figure 5c) found nearly five times as many sources and identified wellheads followed by separators, reciprocating compressors, and other equipment as the most frequent emitters. Of the 379 detected sources, 73% were classed as fugitive leaks and 27% as vent sources. Nevertheless, the ground survey did suggest tanks as the largest sources of emissions, although only one of the 24 detected tanks in the ground survey was measured and the remaining 23 were visually estimated. The reported magnitudes for comparable source types were also different.

For emitting tanks, the difference between the ground survey estimated mean emission rate of 1.3 kg/h and the aerial measured rate of 48.3 kg/h is readily attributed to the unreliability of visual estimates from OGI camera images. Similarly, unlit flares at height are not readily detected by an OGI camera and were not part of the of the OGI field study.[19] However, the aerial measurement results show that unlit flares are an important contributor to total emissions (Figure 5b), suggesting one potentially important gap when relying solely on OGI surveys to screen for sources. Indeed, recent helicopter surveys in the Permian basin point to unlit and poorly performing flares as an underappreciated source of oil and gas sector methane emissions.[29,30]

The difference between measured/estimated emissions from reciprocating compressors is more interesting. The 1.5−53 kg/h magnitude of compressor emissions measured by the plane significantly exceeds the range of compressor seal emissions (0.01−3.0 kg/h) found by the earlier OGI survey. A significant part of this difference would be from unburned methane entrained in natural gas engine-driven compressor exhaust, which is not readily measurable by OGI and was not considered in the ground survey.[19] Recent large-scale field measurements of gathering compressor stations in the United States[31] found that combustion slip was the largest category of methane emissions at these facilities, with a mean emission factor of 2.32 kg/h/unit (range of 0.01−12.5 kg/h/unit[32]). However, at several sites in the aerial survey (Figure 7), emissions attributable to compressors were well above this range, suggesting additional fugitive or vented methane from compressor-related equipment that may not have been fully captured in the OGI survey.

Nevertheless, despite the starkly different magnitudes, both surveys do point to production tanks and compressors as important emissions sources relative to others in each study. Along with unlit flares, the present aerial data show these three sources account for a large proportion of overall emissions, with median measured source rates of 13.7 kg/h for emitting tanks, 8.3 kg/h for emitting compressors, and 5.5 kg/h for unlit flares in the study. For context, federal methane regulations in Canada—which form the backstop for provincial regulations under various equivalency agreements—specify a site vent limit[33] equivalent to 1.03 kg/h. Although new provincial methane regulations for British Columbia[34] do not include a site venting limit, they do prescribe total venting limits equivalent to ~1 and ~7.4 kg/h of methane for all on-site tanks at new and existing sites, respectively. Thus, from a regulatory point of view, the sources seen in the aerial survey are significant.

Notably, under current Canadian methane regulations, unintended leaking or unlit flares and entrained methane

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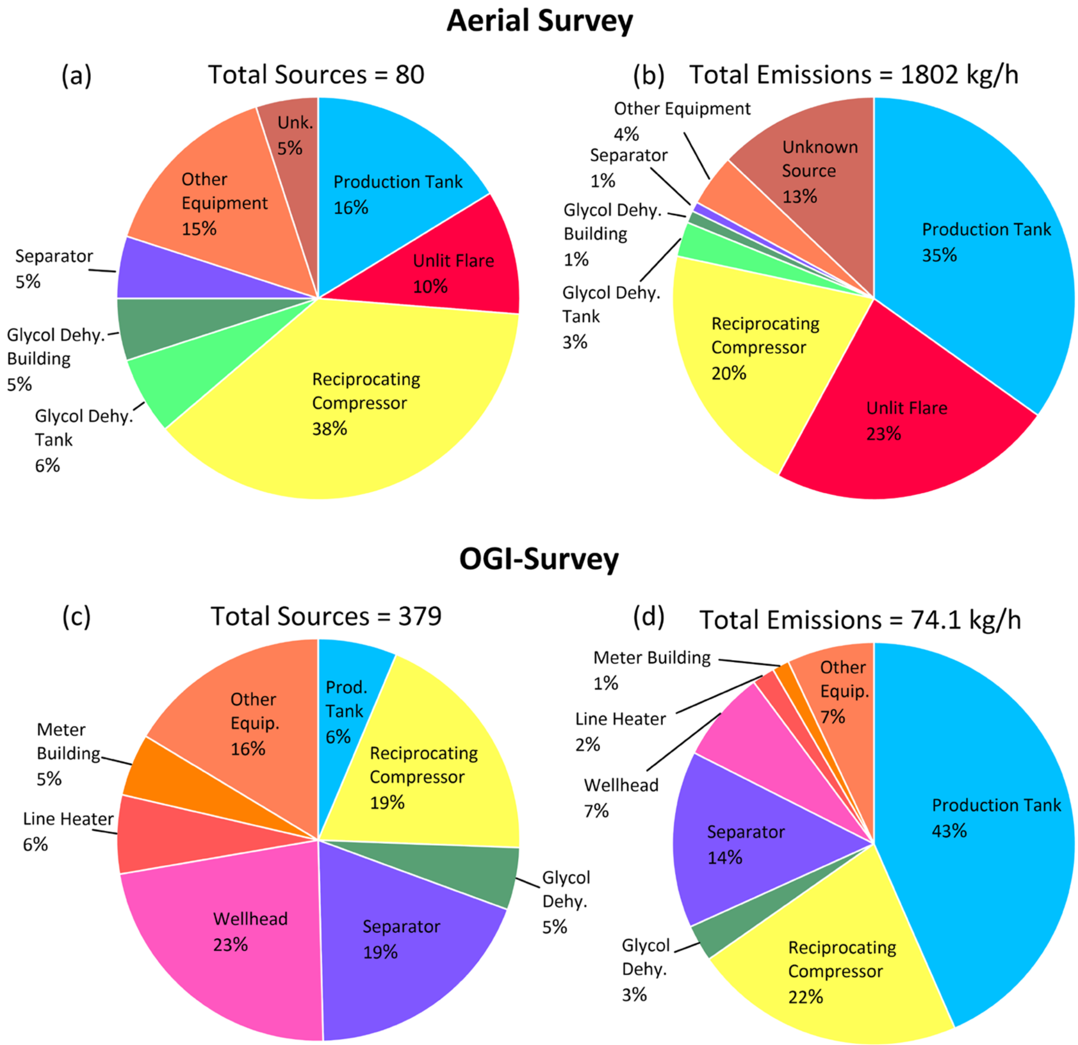

Figure 5. Contrast of aerial and OGI survey source frequency (a, c) and contribution to total measured emissions (b, d) by major equipment type at the same set of sites.

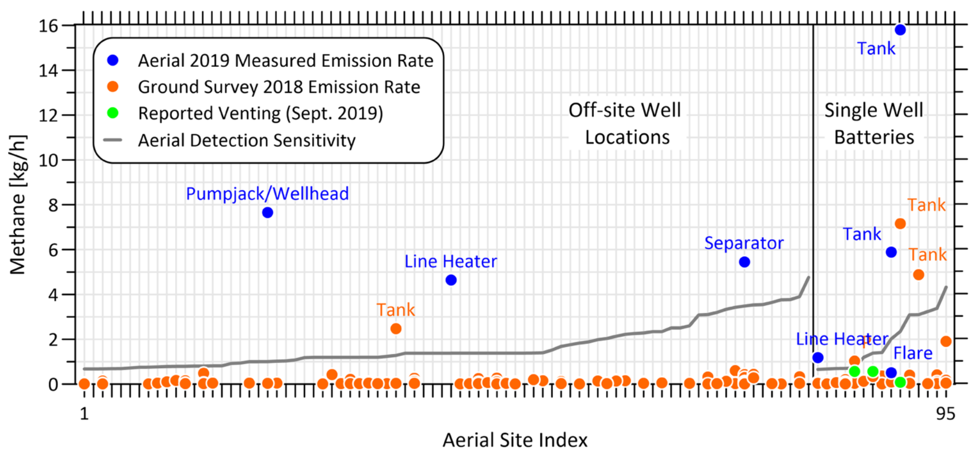

Figure 6. Site-by-site comparison of aerial emissions (labeled in blue) and OGI survey emissions (orange) at 80 off-site well locations and 15 single-well batteries with the estimated aerial lower sensitivity at the time of survey based on wind speed at 3 m elevation above the ground (gray, see Johnson et al.[18]). Industry-reported venting through the Petrinex system (green) was converted from reported natural gas vented volumes for September 2019.

with compressor exhaust are not directly regulated (although flare auto ignitors are generally required). In the case of compressor exhaust, it is possible that the observed elevated emissions may be intentional as part of an operator choice to run lean (i.e., high air to fuel ratios) to reduce oxides of nitrogen (NOx) emissions. Regardless, as both sources occur

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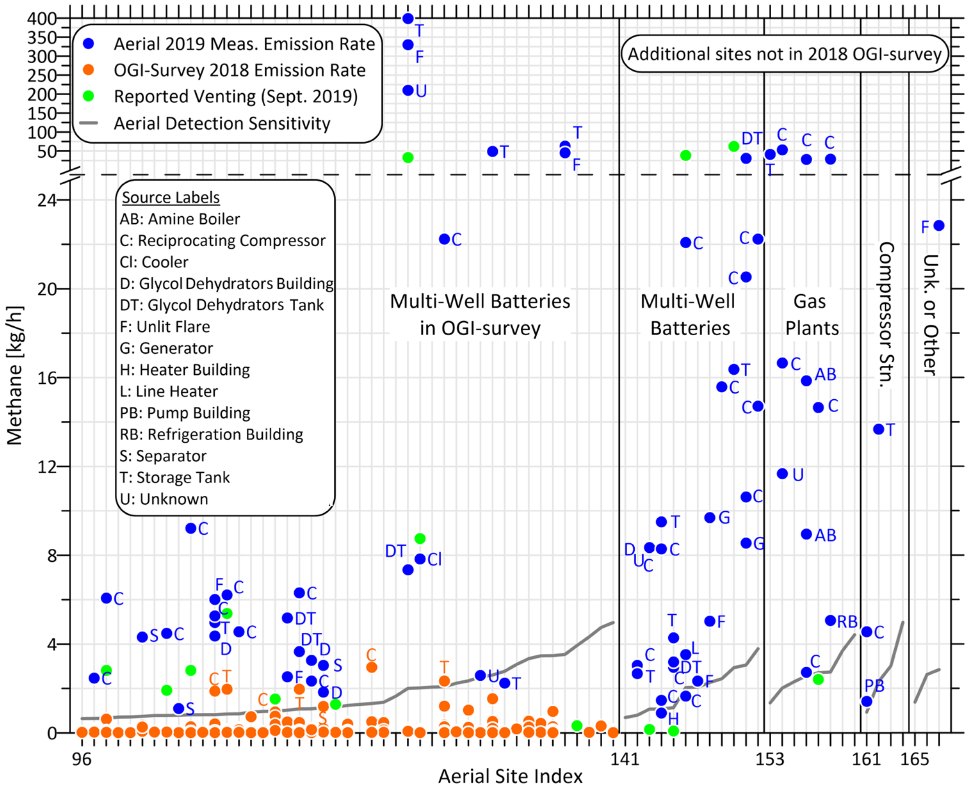

Figure 7. Site-by-site measured emissions for larger facilities in the aerial survey with identified individual source types labeled in blue. The comparison with OGI survey emissions (orange) is shown for the 45 multiwell batteries in both surveys. The estimated GML lower sensitivity at the time of survey based on local wind speed at 3 m elevation above the ground is shown as a gray line (see Johnson et al.[18]), where sites have been ordered by wind speed. The methane contribution from reported venting during the month of the airborne survey (if any) is shown in green for comparison. Note the broken scale on the vertical axis.

at height and may not be readily detected in a standard OGI survey, these sources may go unchecked without some form of secondary compliance screening (e.g., flame-out detection) or aerial survey similar to the present approach as part of an alternative LDAR program. Thus, the finding that over three-quarters of the total detected emissions are attributable to tanks, compressors, and unlit flares (i.e., Figure 5b) has important implications for the accuracy of current methane inventories that rely heavily on OGI survey data.

Site-Level Analysis and Comparisons with Reported Venting Data. To further investigate the differences between the aerial and OGI source magnitudes and how results may be used to improve inventories, individual sources from the two surveys were compared on a site-by-site basis in Figures 6 and 7. Also plotted on both figures is the lower detection limit of the aerial GML system considering the local (on-site) wind speed at the time of detection, as derived from blinded controlled released data.[18] Finally, average venting emissions (if any) reported by industry through the Petrinex system[35] during the month of the aerial survey are shown as green circles, where reported whole gas volumes were converted to methane using a typical methane fraction of 88% by volume. Sites are categorized by type—off-site wells, single-well batteries, multiwell batteries, gas plants, compressor stations, and other—and ordered by increasing wind speed in each category.

A first glance takeaway of Figures 6 and 7 is that the OGI survey found hundreds of small emissions well below the detection limit of the aerial survey and missed finding larger sources like those measured by the airborne GML. In general, there is surprisingly little overlap between the types of sources that are found by the two approaches. For the 105 wells within the 80 off-site well locations (Figure 6), the aerial survey found sources at only 4% of sites; however, the total emission rate of these few sources (17.8 kg/h) was still nearly 50% greater than the total of all 107 sources found at the same sites in the prior ground survey, all but one of which were at levels below the GML detection limit. Thus, although these simple sites—typically with minimal on-site equipment and linked by pipeline to larger proration batteries at a separate location—are much less likely to emit than the single- and multiwell batteries (Figure 7), they can still occasionally be significant sources (at least relative to regulatory limits as noted above). Similarly, at single-well batteries, with the exception of two visually estimated tank vents in the ground survey that were notably above the aerial detection threshold, sources were otherwise distinct between the two studies. The airplane found measurable sources at 20% of single-well battery sites in the survey, which in addition to a wellhead, generally include basic separation and metering equipment and/or storage tanks. It is worth noting that these detection rates are much lower than those estimated in previous truck measurements in this region,[36] even though the nominal detection sensitivities were similar.

At multiwell battery sites (Figure 7), the OGI survey again predominantly found numerous small sources, 97% of which were below the detection limit of the airborne GML. Both the frequency of detected emissions and total magnitudes were higher for the larger facilities of Figure 7 than the well sites and single-well batteries of Figure 6. Overall, the airplane found

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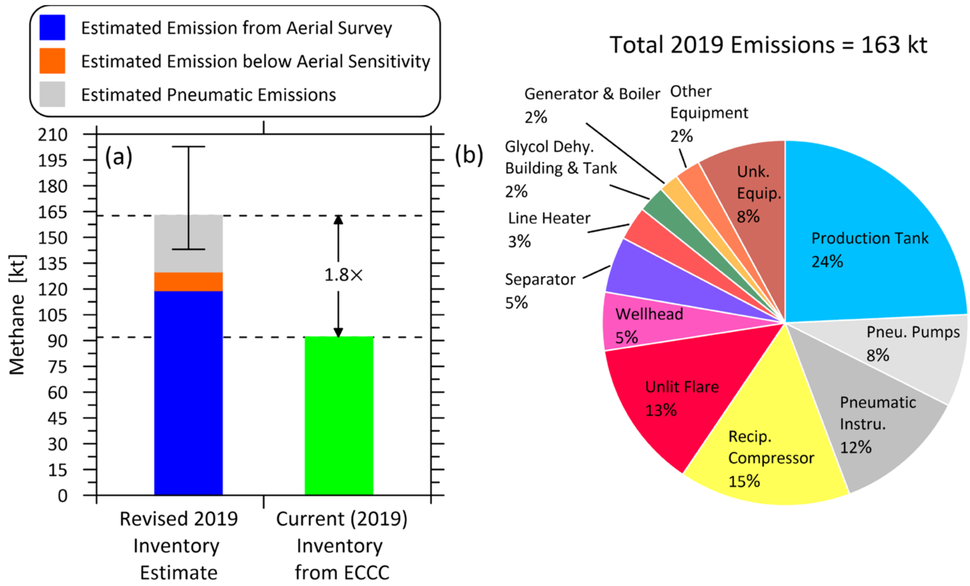

Figure 8. Baseline methane inventory estimates and source categories for the upstream oil and gas sector in British Columbia, Canada. (a) Comparison of new measurement- and on-site pneumatic device count-based overall methane emissions estimated for 2019 with the most current National Inventory estimate for the BC upstream oil and gas sector. (b) Updated breakdown of methane contributions from specific source types in the revised inventory.

measurable sources at 56% of multiwell batteries, 63% of gas plants, and 43% of compressor stations/other facilities. Several multiwell batteries and gas plants had individual sources in excess of 25 kg/h, with one super-emitter site having three sources in excess of 175 kg/h. Although this site also had the third highest level of industry-reported venting among all sites in the survey, the aerial measured emissions were substantially higher and included an unlit flare and a storage tank. In general, for all sites, aerial measured emissions were much higher than either reported venting alone or the sum of reported venting and OGI detected sources. This implies a substantial contribution to overall methane that is not being captured in current vent reporting or by standard OGI surveys.

■ REVISED UPSTREAM OIL AND GAS METHANE INVENTORY ESTIMATE FOR BRITISH COLUMBIA IN 2019

The analysis of Figures 5−7 demonstrates that aerial measurements and OGI survey data are complementary and distinct; for the most part, the two surveys find and measure/estimate different sources of methane. Combining direct measurements and estimates from both surveys thus presents a unique opportunity to better understand the true distribution and magnitudes of total methane emissions. As fully detailed in the SI, aerial and OGI-derived emission source distributions, together with on-site pneumatic device counts collected as part of the OGI survey[19] and industry-reported 2019 production activity data,[35] were used to derive a new, direct-measurement-based, methane inventory for BC from upstream oil and gas sources in 2019.

Starting with only the measured or directly estimated emissions sources in both surveys (excluding pneumatic device emissions), site-type-specific baseline emission rates for off-site wells, single-well batteries, multiwell batteries, gas plants, and compressor stations were estimated (SI Section S3.3) as 0.26 (0.21, 0.35) kg/h, 2.2 (1.6, 3.2) kg/h, 26.7 (19.1, 38.1) kg/h, 28.9 (27.3, 38.4) kg/h, and 5.5 (4.9, 7.8) kg/h, respectively. The 95% confidence intervals on these factors are based on the uncertainty of the aerial measurements and were derived as part of the Monte Carlo analysis detailed in SI Section S4. Considering active facility counts for BC in 2019 (see SI, Section S3.2), and conservatively neglecting any emissions from facility types such as metering stations, pipeline facilities, water and waste facilities, underground storage, customs treaters, and tank farms, which were not measured in the present surveys, a measurement-based estimate of upstream oil and gas sector methane emissions in BC was derived as indicated by the blue and orange bars in Figure 8a.

Next, emissions from pneumatic equipment (e.g., level controllers, transducers, positioners, etc.) and pumps, which were not captured in either study, were robustly estimated (see Section S3.4 in the SI) as in the 2018 OGI survey, combining on-site count data with measured vent rate data from recent studies in BC and Alberta[37−39] considering specific makes and models of inventoried on-site equipment. Conservatively, pneumatic equipment emissions from site types not included in the 2018 counts (e.g., LNG plants, gas plants, custom treaters, compressor stations/gas gathering systems, and tank farms) were also assumed to be zero. Although this approach will again miss some emissions, it is consistent with the assumption that a large fraction of pneumatic equipment at these types of larger facilities may be air-driven.

For comparison, the current publicly available methane inventory for BC estimates 92 kt of methane from the upstream oil and gas sector in 2019,[40] plotted as the green bar in Figure 8a. The measured sources in the aerial survey alone (blue bar) suggest greater methane emissions than are included in the current inventory. Adding in the contribution from smaller sources below the aerial detection limit estimated from the OGI survey data (orange bar) and pneumatic equipment (gray bar) suggest that actual methane emissions from upstream oil and gas sector sources are conservatively 1.8× higher than the current federal inventory would suggest, where the uncertainty range on this estimate is 1.6−2.2× as detailed in Section S4 in the SI. Finally, this new estimate is expected to

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be conservative as noted, since in addition to conservatively assuming zero emissions from detected sources below the aerial sensitivity on subsequent passes (Section S1 in the SI), potential emissions from site types not included in the survey as well as pneumatic emissions at most larger facilities have been completely neglected.

Implications. Perhaps more important than the overall magnitude of the revised inventory, Figure 8b shows the detailed breakdown of methane sources. Nearly three-quarters of emissions are attributed to four main sources: production tanks (24%), pneumatic devices (20%), reciprocating compressors (15%), and unlit flares (13%). These are the sources driving upstream oil and gas sector methane emissions, and specifically, where emerging policy and regulations must focus to achieve meaningful reductions. In particular, tank emissions appear much more important than current inventories might suggest[41] and unlit flares are a second important gap, bolstering observations from recent helicopter measurements in the Permian basin.[29,30] Similarly, total methane emissions from compressors in the present analysis are larger than current Canadian inventory estimates, and much larger than compressor-source emissions reported in the prior OGI survey. Consistent with recent field work highlighting the importance of combustion slip and yard piping to total emissions at gathering stations,[31] this result demonstrates how OGI surveys can not be expected to capture the full nature of methane emissions from compressors. Indeed, although on the same set of facilities the OGI survey found many more sources (97% of which were below the sensitivity limit of the airplane), the aerial survey found as much as 18 times more methane. This has profound implications for the accuracy of current inventories that rely on OGI surveys to derive population emission factors and the potential effectiveness of emerging regulations that rely heavily on OGI surveys to detect fugitive emissions and abnormal venting. By contrast, pneumatic devices—although still quite important at one-fifth of the inventory—are potentially less important than thought, at least in comparison to recent detailed inventory analysis for Alberta, Canada[41,42] and the 35% of methane emissions from oil and gas production estimated in the 2019 U.S. GHG inventory.[43] This difference may also reflect the start of a trend toward more low- and zero-emitting pneumatics ahead of regulatory changes.

The picture is more complicated when considering the breakdowns of contributing methane sources by site type (Section S5 in the SI). Although the above sources dominate overall methane emissions and are the primary sources at battery sites, gas plants, and compressor stations, this is not true at off-site well sites. These isolated sites tend to be dominated by pneumatic device emissions and fugitive sources from a mix of equipment including wellheads and separators. Although individually these sites tend to be small emitters, their large number means they aggregate to 30% of total methane emissions in the inventory. This ultimately suggests a supplementary role for OGI surveys in tackling overall methane emissions from all upstream sources and site types.

However, the main observation from the present analysis remains—the aerial survey found significantly larger sources and many times greater total emissions than the prior OGI survey, which analyzed collectively in conjunction with on-site equipment count data, conservatively suggest methane emissions are 1.6–2.2 times greater than current inventory estimates. Successful attribution of emissions back to individual sources reveals the main drivers of this discrepancy (i.e., storage tanks, compressors, and unlit flares, which account for more than half of all methane emissions in the sector) and imply that policy and regulations that rely on OGI surveys alone risk missing a significant portion of total emissions. So-called abnormal or fugitive venting, not only from major sources such as tanks and unlit flares but also from compressors and pneumatics, can be especially problematic to detect and distinguish. This can be especially challenging when regulations make semantic distinctions between vented and fugitive sources, where intentional venting may be allowed but abnormal or fugitive venting may not. Further work investigating how this revised inventory and source breakdown impact anticipated outcomes of emerging regulations is strongly recommended, recognizing that current regulations and regulatory equivalency agreements have necessarily been based on the understanding of available methane inventory data at the time of development. The newly derived source distributions and average site-level emission factors (with Monte Carlo estimated confidence limits) are presented to help inform this process and, more broadly, should help in finally closing the gap in a range of recent studies noting significant top-down, bottom-up discrepancies in methane estimates.

ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.1c01572.

Identifying sources and emission rates from Bridger GML data (S1); correspondence of aerial measurement sites with OGI ground survey and facility and emission reporting identifiers (S2); development of an updated methane inventory for British Columbia (S3); uncertainty estimation and Monte Carlo analysis (S4); updated 2019 methane inventory figures by site and source (S5); and references (S6) (PDF)

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Notes

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