

Thank you to the reviewers for their positive and valuable comments. We are particularly grateful for the compliments about the quality of preparation, organization, and writing that went into this study. Since the submission of this manuscript, there has been an independent regulator-sponsored study for the same hydrocarbon resource (Montney) at an upstream development just across the provincial border in Alberta. This study strongly validates the CH₄ emission patterns we saw in our work. Not only were the emission frequencies almost identical, but also the volume estimates were very much inline with ours. We are excited to incorporate details of that study into our manuscript to both strengthen and validate our methods and results.

We have addressed each referee and short comment individually below. Revised figures are included here, and we have shown all significant changes to the manuscript text (in colour). We believe that these changes have resulted in an improved manuscript.

Response to Anonymous Referee #1 – RC3

We very much appreciate the reviewer's comments, and are encouraged by the positive feedback and recommendation for publication. Please see below for our response to this review.

General Comments

In “Mobile measurement of methane emissions from natural gas developments in Northeastern British Columbia, Canada”, Atherton et al. describe with lucidity and apply with care an improved mobile survey technique for identifying methane leaks in an understudied region of Canada’s oil and gas fields. The measurements are used to probe which aspects of the oil and gas infrastructure in the portion of the Montney region surveyed are most likely to emit methane. A conservative estimate of the bottom up inventory for entire Montney development is calculated and compared against state-based estimates, which is the most uncertain part of the analysis. The manuscript clearly describes the measurement and analysis techniques, highlights the limitations of the approach, and contextualizes the results nicely. I recommend this manuscript for publication in Atmospheric Chemistry and Physics with only minor changes.

Thank you to the reviewer for this overview of our manuscript. We have made all minor changes to the manuscript that are addressed in the Specific Comments section below.

Specific Comments

Line - Comment

p.2, 1.13 - “ostensibly less environmental impact” – People have been more concerned

about water-based impacts of hydraulic fracturing than those of coal, so restating this perceived advantage to be specific to atmospheric drivers of climate might be more accurate.

We agree, and have changed the wording of this in the manuscript to be more specific about the environmental benefits related to atmospheric greenhouse gas emissions.

“For this reason, natural gas has been deemed a transition fuel on the path to renewable energy because it allows for continued fossil fuel exploitation while emitting a seemingly smaller amount of greenhouse gases.”

p.3, 1.13 - “super-emitters, and reduction” should be “super-emitters and reduction”
We agree and have made this change in the manuscript.

p.3, 1.26 - “significantly, with thousands” should be “significantly with thousands”
We agree and have made this change in the manuscript.

p.4, 1.3 - “August 14 2015 and September 05 2015 we” should be “August 14, 2015, and September 5, 2015, we”
We agree and have made this change in the manuscript.

p.8, 1.20 - “probably” should be “probable”
We agree and have made this change in the manuscript.

p.9, 1.7-8 - Indeed, accurate infrastructure inventories can be difficult to maintain. This statement seems to indicate that the correlations were not what was expected, which led to suspicion of the infrastructure inventories. Could you rephrase this statement to describe the limitations on analysis that uncertainties in the inventory induce?
We have removed some lines from this part of the discussion, and we have instead added some text to the Methods section (under *2.3 Emission Source Attribution*) clarifying uncertainties in the acquired infrastructure inventory.

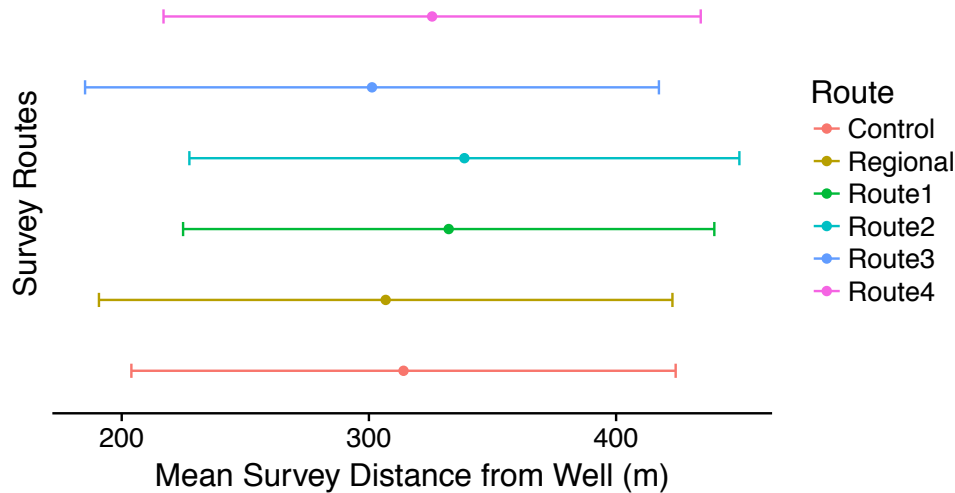
“When possible, we attempted to validate the infrastructure locations in the database during our surveys. The locations of the majority of well pads and processing facilities appeared to be accurate, however the statuses may not have been up to date. For example, well pads recorded as “abandoned” in the database, occasionally still had infrastructure present. Although we could not verify the locations of all infrastructural sources from public roads, we concluded that in most cases, the infrastructure database locations appear to be correct, but the operational statuses might not have been up to date.”

p.7, 1.25 - “FLIR” is first used here, but the acronym is first defined on page 10. Could you please reorder?
This change has been made to the manuscript.

p.12, 1.20-1 - “Montney based” should be “Montney-based”
We agree and have made this change in the manuscript.

Figure 2 - If I understood correctly, industrial sources were passed on multiple routes. Could these dots and bars be color-coded (with colors from Figure 1) by the route on which the source was observed?

For clarity we have re-created this graph to show detection distances on each route. Below is the revised graph and caption.



“Figure 2: Mean distance from infrastructure while surveying each of the six routes listed in Figure 1. One standard deviation from the mean shows the range of distances at which we were sampling downwind of infrastructure.”

Figures 5, 6, 7 – Please add to the caption the meaning of the grey-shaded areas around the line.

In response to a comment from Anonymous Referee #2 (below) we have illustrated these data using bar graphs instead.

Reply to Anonymous Referee #2 – RC1

We thank the reviewer for their constructive review of the manuscript. We have made all of the specific recommended changes. Please see below for our response to each of the comments.

General Comments

* The manuscript is extremely well written. * This paper addresses an important need in the community with a practical and well-described method for estimating emissions rapidly and on a broad scale. * While I understand that there was not an opportunity to benchmark the estimates against other methods of emissions estimation, the lack of validation remains a significant weakness. I nevertheless recommend publication, but this caveat should be recognized at key steps in the analysis. * The largest omission from

*the paper is the lack of any uncertainty estimate for the emissions from the region. Some effort should be made to rectify this in the final paper. * I don't understand the use of linear regressions (with variable slope and offset) for the detection rate estimates. Justification of why this analysis should be used over the simple calculation of rate = emitting sources / total sources should be provided, or the authors should revert to the simpler analysis.*

We appreciate the reviewer's general comments. The reviewer's concerns surrounding both uncertainty estimates and the linear regression plots are dealt with more explicitly in the Specific Comments section. We have addressed these comments in detail below.

Specific Comments

- P1 L17: emissions estimates for the Montney development does not have an uncertainty estimate. It is difficult to interpret the emission results without an uncertainty associated with it.

In our study we have made a minimum emissions estimate by combining the minimum detection limit of our applied method with our calculated emission frequencies for the infrastructure in the survey area. We expect that the total CH₄ emission volume for the area is higher than our reported estimate.

A regulator-sponsored FLIR study was released at the same time we submitted our manuscript to ACP (GreenPath (2017)). The study was independent of ours, but took place in the Alberta portion of the Montney formation (the same play that is being developed in the field area of our study). The study by GreenPath Energy reported almost identical emission frequencies and emission volumes as we calculated for our field area. The results of our study reinforce the emission patterns of the GreenPath study across a larger sample size.

We have added the following text to section 3.4 *Methane Emission Inventory Estimate* of our manuscript to address how this newly released study validates our method of volume estimation.

“Our emission frequency calculation for Active wells (0.47) was very similar to the emission frequency of 0.53 that was recently calculated in the Alberta Montney near Grande Prairie (GreenPath, 2017). Our method of calculating emission frequencies is corroborated by this recent FLIR study in the Alberta Montney, which increased our confidence in using emission frequency calculations to estimate a minimum CH₄ inventory for the development.”

- P5 L1 - 10: The authors state that they are using excursions in the eCO₂:eCH₄ ratio (<150) as indications of natural gas emissions. However, I would imagine that other sources of CO₂ could add noise to this ratio (especially since there are other vehicles that contribute to excess CO₂). Figure 3 further indicates this issue. A fairly obvious alternative would be to use the same RMRI algorithm and use eCH₄ > threshold as a criterion for when emissions are detected. It would be helpful if the authors could

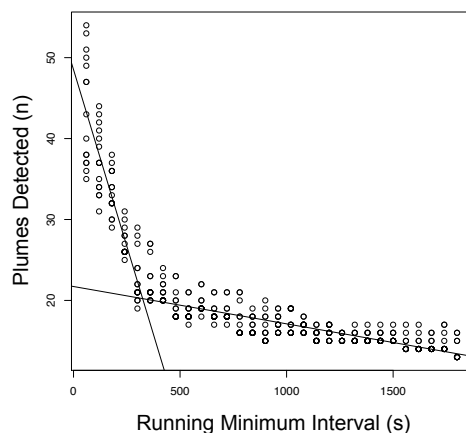
provide some more justification why the ratio $e\text{CO}_2:e\text{CH}_4$ is a better metric than simply $e\text{CH}_4$.

The method of using excess ratios (particularly $e\text{CO}_2:e\text{CH}_4$) for plume source attribution in an upstream oil and gas environment is described in Hurry et al. (2016). We have added the following text to the manuscript in section 2.2 *Identification of Natural Gas Emissions* to clarify that a detailed explanation of the method can be found in this paper.

“This $e\text{CO}_2:e\text{CH}_4$ approach has proven to be a useful fingerprinting tool in oil and gas environments because a single ratio value can help elucidate the presence of multiple emission source types. In this study, we follow a procedure similar to Hurry et al. (2016), and a detailed explanation of the method is described in that paper.”

- P5 L10-12: *"Our optimal RMRI was taken to be the point at which anomalies were maximized, but also where we avoided the rapid noise-associated increase associated with extremely short RMRI's": in practice, how was this optimization performed? It appears to be a subjective choice. Is this true? It would be preferable if the choice was made objectively using quantitative criteria; it would also be preferable to have the same algorithm be used for all surveys.*

We did not choose the RMRI value for each survey subjectively. The optimization was performed with an algorithm that was applied to all surveys individually. We have added the following figure and associated text to the paper to clarify the quantitative process we used to determine the RMRI for each survey. Please see the figure, caption, and revised text below.



“Figure 2: Example of a regression plot that demonstrates the optimization process we used to calculate an RMRI for each survey. The RMRI for each survey was chosen where the two linear regression lines intersect.”

- P5 L 18-19: *"Combustion values were also recorded along the routes when $e\text{CO}_2:e\text{CH}_4$ exceeded 1000, and were related to vehicle tail-pipe emissions and industry". What does 'combustion values' mean?*

This sentence has been re-worded in the manuscript to better explain how we filtered out emissions related to combustion.

“We also detected occurrences of combustion emissions along our survey routes, and we differentiated them from other emission sources by filtering out all values where $e\text{CO}_2:e\text{CH}_4 > 1000$. Combustion-related emission sources include vehicle tailpipe emissions and industry (ex. power generation).”

- P5 L24-25: *"because ratios are more conservative than concentrations in valleys and other areas where pooling of gases is common, and fewer false positives are likely" - doesn't the RMRI algorithm take care of slowly varying concentrations of CH₄? It would be good to demonstrate clearly why $e\text{CO}_2:e\text{CH}_4$ is an advantage; if one were to reproduce this method at a larger scale, it would be good to provide clear understanding of why the CO₂ concentration is required.*

It is possible that $e\text{CH}_4$ would have been sufficient and may well have given similar results with few false positives. However, the excess ratio technique is established to be more useful in areas of complex upstream geochemistry to partition a number of emission source types (please see answer to comment P5 L1-10 for explanation and reference to Hurry et al. (2016)). We did not resolve multiple peaks within the excess ratio density plots (Fig. 4 in the revised manuscript), which we would expect to see if there were multiple source types throughout our surveys. The excess ratio technique provided confidence that the source types are related to the infrastructure to which we were proximal during our surveys.

- P5 L28-30: *why was the value 150 selected? What is the effect of this selection on, for example, the emissions estimate, the number of emitters detected, the detection limit, etc. Similarly, what is the effective limit on detection of the system, in units of $e\text{CO}_2:e\text{CH}_4$?*

The value of 150 was selected based on peaks in the $e\text{CO}_2:e\text{CH}_4$ density distributions (Fig. 3). Although there is not a clear peak on each graph, many of the routes showed leveling out of the “natural” peak (~215) near 150-175. We chose 150 to be conservative, and it acts similarly to setting a methane excess threshold. Since our survey routes were focused in areas of dense oil and gas development, the elevated density of emissions with $e\text{CO}_2:e\text{CH}_4$ values <150 were interpreted to be from oil and gas related sources. The value of 150 was also considered to be conservative enough to exclude diluted CH₄ from natural sources. Also, the exact ratio threshold often does not affect the number of plumes detected, but rather the width of the plume (duration while surveying), which is not pertinent to this study.

- P6 L7: *are there any estimates of cattle emission in this region that could be included?* We were unable to retrieve this information for the fieldwork area and dates. However, our use of a 50% emission persistence threshold for identifying emitters likely rules out the possibility that we included emissions from livestock in our calculations.

- P7 L10: how is this probability defined? Per mile? Per second? For the whole route? This isn't clear.

This probability was defined for the whole route. We have now clarified in the manuscript that we calculated the probability of false plume detection for the entire Control Route.

- P7 L1-5: The kernel density plots do not have a clear knee below 215. Where is 150 on this plot? why was 150 selected, and not 125 or 175, for example?

Please see answer to comment P5 L28-30.

P7 L16-20 and Fig 4. Was wind direction used to evaluate whether a plume should have been detected from the green well pads? Are the databases of well locations up to date? Was there an effort to corroborate locations with on-ground survey or satellite imagery?

The source location databases were up to date at the time we retrieved them (July, 2015). Locations of the majority of sources in the database near our surveys were verified during the on-ground survey campaigns. A section has been added to the manuscript about the uncertainty in infrastructure inventory in response to a comment from Anonymous Referee #1 p9 1.7-8. We have also reworded the caption of Figure 4 (now Fig. 5 in revised manuscript) for clarity.

“Figure 5: A subset of infrastructure locations that we surveyed during our field campaign in attributed form. This figure serves as an example of how we attributed wells and processing facilities to on-road plumes. Grey lines represent the survey route. In this case 31 wells or facilities were surveyed, and we used our attribution technique, which accounts for wind direction and distance to source, to determine whether or not these wells and processing facilities were probable emission sources.

P7 L32: "it had to have > 50% emission persistence." Similarly, did persistence include wind direction? In other words, did persistence include whether the potential source was upwind of the vehicle at the moments the vehicle passed by?

Yes, our calculation of emission persistence included only the sources we had sampled. And in order for a source to be considered sampled, at least three successive datapoints had to be downwind and within 500 m of the infrastructure in question. We have clarified this in the following section of the manuscript:

“In this study, emission persistence is defined as the number of surveys on which a CH₄-enriched plume was attributed to a piece of infrastructure, divided by the number of times we surveyed that infrastructure in the downwind direction. A plume was only attributed to a piece of infrastructure if we recorded three or more successive CH₄-enriched measurements within 500 m in the downwind direction of the source. And in order for a piece of infrastructure to be classified as an emission source, it had to have > 50% emission persistence.”

P11 L8: "concentrations will decrease exponentially away from a release source": the dependence on distance is not exponential. Gaussian plume models predict something

like $\sim 1/d$ to $1/d^2$, for example.

Thank you for pointing this out. We have removed “exponentially” from this sentence in the revised manuscript.

P11 L11-18: Wouldn't nearby plumes (with faster time signatures) be diluted more than more distant plumes? And wouldn't the peak area (in time) be conserved for short pulses? This is a very big adjustment of the concentrations and therefore the emissions. Did you use peak height or peak area to estimate emissions?

Gaussian plume analysis depends on plume centerline concentrations, not widths.

P12 L9: Rather than using the MDL as the average estimate of emissions, wouldn't it be possible to actually craft an estimate of emissions given the plume dispersion model and estimated distances?

The process of calculating emission rates using Gaussian plume dispersion for each individual datapoint is computationally intensive because of the amount of measurements collected. The technique of applying volume estimates to mobile survey data was not developed at the time we processed these data. Our research group is currently developing a similar technique of volume estimation, but this will be part of a separate study and ground validation is still required.

p12 L28: It is important to include some uncertainty estimates for the emissions estimate. Even a simple low and high estimate of error is better than nothing. For example, the estimates of errors on the slope of the active wells could be used to bound the estimate.

Please see our answer to comment *P1 L17* from Anonymous Referee #2 for an explanation of added text about method validation. The linear regression plots have also been changed to bar graphs in response to comment on Fig. 5, 6, and 7.

p14 L9: It's not clear how this method identifies super emitters, since the authors do not present a clear method for quantifying emissions and identifying the largest emitters. How does this method help identify the largest emitters?

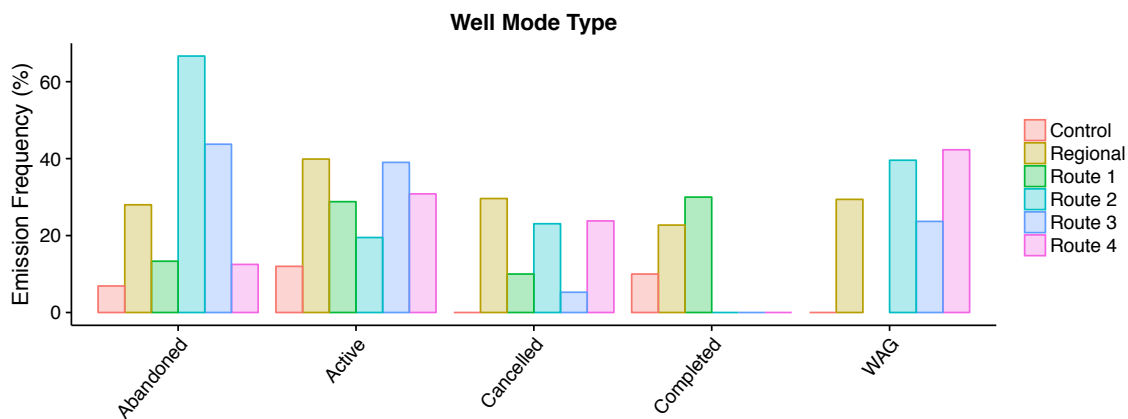
This section of the manuscript is referring to the benefits of using an on-ground detection method that surveys a large fraction of infrastructure throughout the development. In comparison to emission factor inventory estimates, we are more likely to have captured emissions from super-emitters. We have added the following text to section 3.1 *Measured Gas Signatures* to address our results relative to what would be expected from super-emitting sites:

“We did not see any CH₄-rich plumes that would be characteristic of a super-emitter. This is evident by the fact that the maximum raw CH₄ value we recorded was low (8.148 ppm). These low emission magnitudes are inline with results from GreenPath Energy (2017), which used FLIR cameras to assess emission sources in the Alberta portion of the Montney formation.”

Fig 5: In some panels (e.g., the top panels), the regression lines do not pass through zero. This doesn't make any physical sense. Why should there be a threshold for number of wells surveyed below which no emissions should occur? Why would there be no emissions for surveys with fewer than 60 wells surveyed? I don't understand the rationale for a linear regression. Why not simply ratio the total number of sites with emissions / total number of sites surveyed across all surveys for each category? This would make more intuitive sense. Alternatively, the linear regressions could be forced through zero, which would be similar.

Fig 6 and 7: similar comments to above for Fig. 5.

We agree and have changed the linear regression plots to bar graphs which show the percentage of infrastructure emitting for each source-type. Please see the graphs and captions below. We have also made minor changes to the manuscript text accordingly.

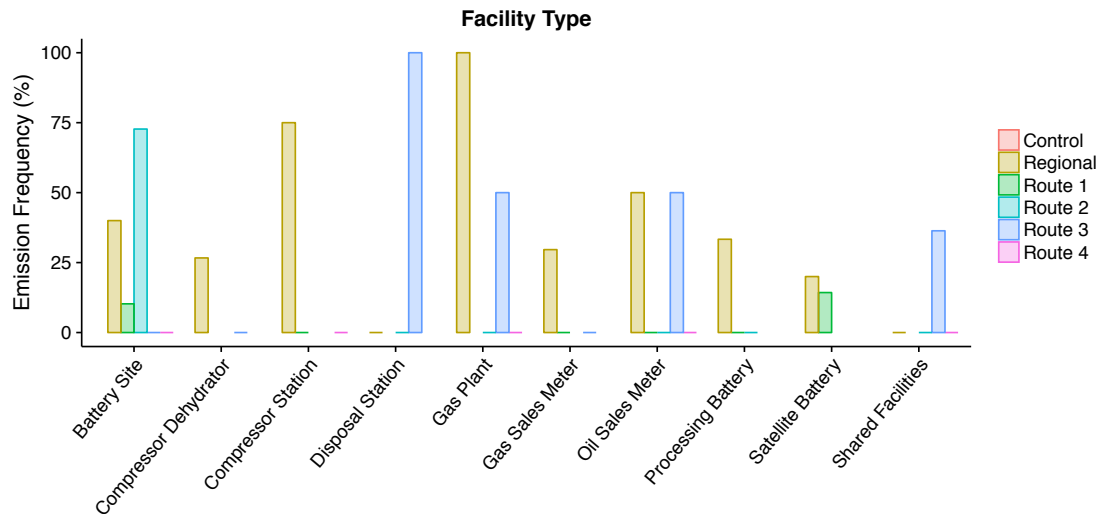


“Figure 6: Emission frequencies for each well mode type for all surveyed infrastructure on each route. These emission frequencies were considered in our total emissions inventory calculations.”



“Figure 7: Emission frequencies for each well operation type for all surveyed infrastructure on each route. Certain operation types for which we did not have a

representative sample are not included (such as Injection, Disposal, and Observation wells).”



“Figure 8: Emission frequencies for each facility type for all surveyed infrastructure on each route. These emission frequencies were considered in our total emission inventory calculations.”

Fig 8: Is the occurrence structure due to the fact that some areas were surveyed only three times, which did not allow for a 50% persistence point, for example? This set of plots is a bit confusing.

(This is now Figure 9 in the revised manuscript). In this figure, “Occurrence” (y-axis) refers to the number of pieces of infrastructure emitting at each level of persistence (x-axis). The y-axis has been re-named to “Unique Wells/Facilities (n)” for simplicity. Below is the edited caption.

“Figure 9: The cumulative number of unique wells/facilities versus emission persistence (%) across all 30 mobile surveys. Persistence refers to the repeated tagging of a piece of infrastructure as a possible emission source based on the method of plume attribution we applied in this study.”

Fig 9: what do negative mean eCH4 excursions mean (gray bars of lower panels)?

(This is now Figure 10 in the revised manuscript). We have removed the grey error bars from this figure. Below is the edited caption.

“Figure 10: Effect of infrastructure age and operator size on detected emissions. The size of the dots represents the number of samples taken. Red dots are those recorded at the 100% persistence level, green dots are at 50% persistence.”

Fig 10: could you add in the survey paths on this plot for reference?

(This is now Figure 11 in the revised manuscript). We have chosen not to add the

survey routes because the size of the dots already represents the sample size in each area.

Typographical error and other small comments

P1 L13-15: "older infrastructure tended to emit more often (per unit) with comparable severity in terms of measured excess concentrations on-road." - unclear; per unit? what is a unit? reword for clarity, please.

"Unit" was referring to each individual piece of infrastructure. This has been reworded in the manuscript for clarity.

"Multiple sites that pre-date the recent unconventional Montney development were found to be emitting, and we observed that the majority of these older wells were associated with emissions on all survey repeats."

Reply to Anonymous Referee #3

We thank the reviewer for their thorough and detailed review of the manuscript text. Highlighted below are changes to the text we have made to address the suggested revisions.

The authors present data and analysis from six mobile measurement surveys in the Montney formation which include methane emission concentration and rate information from 1600 passes near wells. The routes were surveyed 3-6 times each and designated as new wells, old wells, and a control. The authors use the methane and CO₂ concentration and meteorology data to calculate emission rates of methane from wells. They analyze the data using online well number, production, age, etc. information to show which types of wells or activities emit most or most often. And finally, they compare their results to available data from recent studies in other formations in U.S. Collection of mobile data, especially when one is at the whim of wind to assure downwind of well measurements, is no easy task. The authors have conducted a great survey of sites in the Montney formation. This study is exactly the type of research that is needed to clarify and quantify the emission rates of methane from different formations and sources. The authors have done a lot of work and the publication of this paper (especially with the availability of the data upon request, as noted at the end of the manuscript) will be a great addition to the current body of knowledge on methane emissions from oil and gas sources. However, there is some more analysis, organization, and sentence structure improvement that is needed for this paper before publication. Please see my General and Specific comments below:

General Comments

1. Various groups have used different approaches to quantifying methane emission rates (e.g., EPA's OTM 33 method, use of different tracers for close or far quantifications using

the Tracer Ratio Method, reverse plume modeling, etc.). One of the things that all the methods above have in common is method validation. It seems that the authors of this paper have not conducted any method validation studies. This is a major weakness in the study. I would recommend that a quick methane and CO₂ release study and measurement be added to the paper. However, I understand that time and funding may not be available to do this. Instead, I suggest the authors do a detailed uncertainty analysis (maybe even add a section to the paper) where they discuss and calculate a theoretical uncertainty for their measurements and calculations. The authors have a short section on this, but since no method validation has been done, the uncertainty analysis should more exhaustive.

Please see our response to comment *P1 L17* from Anonymous Referee #2 for information on method validation and how our calculations are very similar to results from a recent study at a nearby oil and gas development accessing the same hydrocarbon formation (GreenPath, 2017).

The primary objective of our study was to collect data on emission frequencies and to establish what infrastructure types emitted most frequently. Minimum volumetric estimates were included, but were not the main focus. Calculating emission frequencies for every oil and gas development is important because it determines the number of wells/facilities by which emission factors should be multiplied in order to achieve an accurate emissions inventory estimate.

We have added the following text to section *1 Introduction* of our manuscript to clarify that emission frequency calculations were the main objective of this study.

“In this study we used a multi-gas (CO₂, CH₄) mobile surveying method that uses ratio-based gas concentration techniques and wind data to detect and attribute on-road CH₄-rich plumes to the infrastructural sources of natural gas developments in northeastern British Columbia, Canada. [Our primary interest in this study was to determine the frequency of emissions, and the relationship between emissions and specific classes of infrastructure.](#)”

2. Another point that is not clarified in this paper is the difference between measurements made from unconventional vs conventional wells. The authors make a distinction between new and old wells. They attribute the increase in the oil and gas activity in the area to the use of unconventional extraction methods. However, when they discuss the wells measured, they do not show any information on the unconventional vs conventional wells. Are all the wells measured unconventional?

The area we surveyed in Northeastern British Columbia mainly produces unconventional natural gas. A large majority of gas wells we surveyed use unconventional techniques of extraction (hydraulic fracturing and/or horizontal drilling). We included one survey route that targeted an area of conventional oil development for comparison (Route 1). The increase in development in the area over the last decade has been from unconventional natural gas infrastructure (discussed in section *1 Introduction*). Information about what type of

infrastructure is on each route is included in section 2.1 *Field Measurements*. And the difference in emission frequencies from oil and gas infrastructure is shown in Figure 8 (now Figure 9 in the revised manuscript) in the chart titled Well Fluid Type.

3. The authors do not distinguish between short term operations and permeant emission sources in their calculations. This may be difficult to do, but at least a discussion of how these would affect the regional emission calculations should be added.

In this study we look at emission persistence in terms of survey repeats. To be conservative in our method of identifying emitting infrastructure, we only tagged infrastructure as emitting if we detected CH₄-enriched plumes within 500 m downwind at least 50% of the times we surveyed it. For many of the pieces of infrastructure we surveyed this means it was associated with a plume downwind on three out of six surveys. We have added text to clarify this in section 3.4 *Methane Emission Inventory Estimates*.

“This value is likely a conservative estimate because it is the smallest value detected at our mean detection distance (319 m), and the majority of our emission detections occurred around this value (Fig. 3). It is also conservative because our method of attribution only considers the wells and facilities that were persistently associated with downwind plumes.”

4. Some of the writing in the paper is confusing. The sentence structures do not flow well. I have given some specific examples of this in the “Specific Comments” section, but strongly suggest the co-authors who were not directly involved in the writing of the manuscript read the paper and comment on sections. Sometimes it is easy for the authors to unintentionally disregard clarity as they themselves are so familiar with the subject of the study.

We have combed the manuscript with this comment in mind and improved the phrasing as recommended in the “Specific Comments” section of this review.

5. The authors use two different tenses and two different voices (active and passive) throughout the paper. I suggest choosing only one. Two different voices and tenses make it confusing for the reader and require re-reading of sections.

We have made all necessary changes to move from passive to active voice.

Specific Comments

1. Abstract: The writing style of the abstract does not lend itself to clarity. The flow of the sentences is not coherent. I suggest re-writing it for better clarity and flow. For example: “We also observed emissions from facilities of various types that were highly repeatable.” is one of the sentences that is unclear and confusing. Or “This value exceed reported bottom-up estimates of 78,000 tonnes for all oil and gas sector sources in British Columbia, of which the Montney represents about 55% of production”. The abstract starts very abruptly. I suggest rewording the first sentence.

The following sections of the abstract have been revised for clarity, as well as

sections addressed in response to comment from Anonymous Referee #2 p1 L13-15.

“In August to September, 2015 we completed almost 8,000 km of vehicle-based survey campaigns on public roads dissecting oil and gas infrastructure such as well pads and processing facilities.”

“Emissions from gas processing facilities were also highly repeatable.”

“This estimate for the Montney area exceeds reported bottom-up estimates of 78,000 tonnes methane for all oil and gas sector sources in the province. Current bottom-up methods of methane emission estimates do not normally calculate the fraction of emitting infrastructure through thorough on-ground measurements. However, this study demonstrates that mobile surveys could be used to gather a more accurate representation of the number of emission sources in an oil and gas development. This study presents the first mobile collection of methane emissions from oil and gas infrastructure in British Columbia, and these results can be used to inform policy development in an era of methane emission reduction efforts.”

2. Page 1, Line 2: What do the authors mean by “incidence”?

“Incidence” was used interchangeably with “emission frequency”. This sentence has been reworded for clarity, and “incidence” has been changed to “emission frequency” throughout the text of the manuscript.

“This study examined the occurrence of methane plumes in an area of unconventional natural gas development in northwestern Canada.”

3. Page 1, Line 4: Are authors including all oil and gas locations in “development”. I suggest clarifying this or using a different word.

“Development” refers to areas where oil and/or gas is being extracted, and oil and gas infrastructure is dense. It has been changed in the abstract, and defined when it is first used in the manuscript.

“North American leaders recently committed to reducing methane emissions from the oil and gas sector, but information on current emissions from areas of unconventional natural gas extraction in Canada are lacking.”

4. Page 1, Line 6: The use of “infrastructural” here has the same problem as the previous comment.

“Infrastructural” refers to oil or natural gas infrastructure, including wells and processing facilities. This has also been reworded in the abstract and defined in the manuscript for clarity.

“To attribute on-road plumes to oil and gas related sources we used gas signatures of residual excess concentrations (anomalies above background) less than 500 m downwind from potential oil and gas emission sources.”

5. Page 2, Line 5: What do the authors mean by “a petroleum system”.

A petroleum system is a term defining all the necessary geological components and processes required for the formation and accumulation of hydrocarbons.

6. Page 2, Line 14: Please rewrite “Over a 100-year... (ICPP, 2014)” for clarity.

This sentence has been revised for clarity.

“The radiative forcing of CH₄ is greater than 30 times that of CO₂ over a 100-year timespan.”

7. Page 2, Line 33: I have noted this in the abstract too. Please describe what you call “infrastructure”.

Please see answer to comment 4. Page 1, Line 6 above.

8. Page 3, Line 1,2: Please re-write sentence for correct grammar.

This sentence has been revised for clarity.

“Furthermore, it is important to note that emission frequencies may vary between developments because of operator best practice, or due to the properties of the geological formation that the hydrocarbons are being extracted from.”

9. Page 3, Line 13: Please define “super-emitters” and use appropriate references.

This sentence has been changed to include all emission sources.

10. Page 3, Line 26: Do the authors have some estimate of numbers of wells?

We have revised this line discussing the increase in natural gas production to the following:

“These unconventional methods yielded 4-5 times more natural gas from the Montney formation than conventional techniques that were attempted prior to 2005. Since then, production of BC unconventional natural gas has increased significantly, with the Montney play being the largest contributor in the province (BC Oil and Gas Commission, 2012).”

11. Page 4: The authors use the words unconventional and hydraulically fractured interchangeably. These two do not mean the same thing. Unconventional oil and natural gas extraction refers to both hydraulic fracturing and horizontal drilling.

The use of “hydraulically fractured wells” has been changed to “unconventional wells” where appropriate throughout the text of the manuscript.

12. Page 4, Line 8: Is 1Hz frequency the rate of data collection?

Yes, it is the rate of data collection. This sentence has been reworded for clarity.

“In total we surveyed 7,965 km of public roads, with an average route length of 248 km. We collected gas concentrations and wind data at 1 Hz frequency while surveying.”

13. Page 4: What were the average distances from wells? If this data is available, can it be used with meteorology data for plume dispersion modeling?

We calculated the average distance from wells and used this value with plume dispersion modeling to calculate our minimum detection limit in section 3 *Results and Discussion* of the manuscript.

14. Page 4, Line 14: Please re-write for correct grammar.

This sentence has been reworded to the following:

“We surveyed four of the routes six times throughout the field campaign, and the two remaining routes (including the Control Route) three times each. We repeated surveys on multiple days to account for varying wind directions. Repetitions of each survey route included both morning and afternoon drives to incorporate varying atmospheric conditions. We also used the repeated survey data to obtain statistics on emission persistence.”

15. Page 4: Please note which routes the numbers are based on in Figure 1.

We have referenced the route names from Figure 1 in this section.

16. Page 4, Line 19: What do the authors mean by “raw” ?

We used the term “raw” in this section to make clear that no processing was done to the atmospheric gas concentrations at this phase of data collection.

17. Page 4, Line 23: What are wind speed units?

The wind speed was measured in km/h. We have added this information to the manuscript.

18. Page 4, Line 25: Since the authors have given the manufacturer of the other instruments used, why not indicate what type of GPS was used?

The type of GPS used has been included in the manuscript.

19. Page 4, Line 32: Please re-write “However, our surveys. . . unusable.” for clarity.

This sentence has been rewritten to the following:

“The survey routes in our study were multiple hours long each and were often routed through various land use types. For this reason, we did not use the traditional methods of calculating background atmospheric gas concentrations.”

20. Page 5: Were the same approaches used for both CO₂ and CH₄ data handling and analysis? Please add a few sentences to clarify this.

Yes, we used the same method of data processing for all gas measurements collected (CO₂ and CH₄). We have added text to clarify this in the manuscript.

21. Page 5, Line 10-12: Please add some statistical data.

Please see answer to Anonymous Referee #2 P5 L10-12. We have added an example plot to explain our method of choosing the RMRI.

22. Page 5, Line 20-21: Please re-write for clarity.

We have rewritten this sentence to the following:

“We identified CH₄ plumes from oil and gas infrastructure in areas where there were multiple successive datapoints with depressed eCO₂:eCH₄ values.”

23. Page 5, Line 21: What do the authors mean by “normal air”?

The term “normal air” has been changed to “ambient air” in the manuscript.

24. Page 5: What are some sources of CO₂ in the area? As this can be a major concern in your calculations, please add a few sentences to address this.

As detailed in Hurry et al. (2016), the ratio technique helps identify (and remove) measurements that are enriched with respect to CO₂. We have included the following text in section 2.2 *Identification of Natural Gas Emissions* to describe possible sources of CO₂ emissions in the area:

“Variation of CO₂ within the survey area was likely primarily a function of oilfield processes (emissions, engines, flares) because there was little industrial activity on the survey routes that was not related to oil and gas development.”

25. Page 6, Lines 1-2: Please re-write for clarity.

We have rewritten this sentence to clarify.

“Otherwise, all in-place oil and gas infrastructure were considered possible emission sources.”

26. Page 6, Line 2: What do the authors mean by “developmental”?

The term “developmental” meant that the well was under development. This term has been removed and this sentence has been reworded to the following:

“The infrastructure database included the well and facility locations, as well as various attribute data such as infrastructure types, statuses, and spud dates (drilling dates).”

27. Page 6: Are there any large dairy operations in the area?

We did not encounter any large feeding operations while surveying. We only encountered smaller farms for which a database of locations could not be obtained.

28. Page 6, Line 15: Please re-write sentence for clarity.

We have rewritten this sentence for clarification.

“We collected atmospheric gas concentration data along 30 surveys of six different routes. The routes ranged in length from 200 - 550 km, and the oil and gas infrastructure located on these routes was managed by more than 50 different operators at the time of surveying.”

29. Page 6, Line 16: *I thought the authors used one route as control. Did they actually make measurements from oil and gas structures on this route and include them in the analysis? If yes, then should the designation not be changed?*

The route we used as a control had significantly less infrastructure. This allowed us to visually compare sections of the surveys near infrastructure, and sections far away from infrastructure. We only used the Control route datapoints > 5 km from any infrastructure to calculate the fraction of false positives.

30. Page 6, Line 19: *Following up on the previous comment, please give numbers of the differences in the oil and gas densities.*

The amount of infrastructure on each route (sampled and emitting) is listed in Table 1.

31. Page 6, Line 30: *What was the speed of the car during these measurements? This is important as it can have an impact based on the width of the plumes.*

The vehicle speed was variable due to the speed limits on the public roads we were surveying. Plume width was not incorporated into any of our measurements, including our estimate of leakage rate. For this reason we have not included vehicle speed in the manuscript.

32. Page 6, Lines 31-32: *What is the difference between 314 and 319 meter designations? Also, should this not be in the methods section instead of the results section?*

We calculated average distances between the survey route and infrastructure for two scenarios: the first being datapoints when we were sampling infrastructure (314 m), and the second being when we were detecting emissions from infrastructure (319 m). We have reworded these lines in the manuscript to clarify this point. These values are not in the methods section because they were calculated from the collected data and the locations within the infrastructure database.

33. Page 7, Line 1: *What do the authors mean by “In each, we see a peak of signatures near ~215 which is representative of natural”?*

This sentence has been reworded in the manuscript to the following:

“In each density plot, there is a peak where $eCO_2:eCH_4 = \sim 220$, which is representative of the ratio between ambient CO_2 and CH_4 .”

34. Page 7, Line 5: *relative to what?*

For clarity, we have reworded this sentence to the following:

“The kernel density plots in Figure 1 show that, in all of the survey routes except the Control, we see a population of CH_4 -enriched anomalies (less than the natural ratio of 220), that are the result of localized plumes from natural gas development.”

35. Page 7, Line 25: *What are the other methods?*

“Other” was a typographical error that has been revised.

36. Page 7, Line 27: Should this be associated?

We have removed the word “associate” from this sentence.

37. Page 7, Line 30: Please define what you mean by “. . . a piece of infrastructure. . .”

The use of the term “infrastructure” in this manuscript refers to oil and gas related infrastructure such as well pads and processing facilities. This is described earlier in the manuscript in response to comment 4. *Page 1, Line 6.*

38. Page 7, Line 32-34: Please re-write for clarity.

We have reworded this in the manuscript to make this point more clear.

“Our technique of background subtraction is tuned to resolve small, localized plumes, but it should be noted that atmospheric conditions have a significant...”

39. Page 7: I suggest adding clarifying sentences like, Well pads were the most common oil and gas structures encountered/sampled during our survey (%# of total sites).

We have added the following lines to help refine this section of the manuscript.

“Well pads were the most common type of oil and gas infrastructure sampled during our surveys (58% of total infrastructural emission sources).”

“Emitting infrastructure includes wells and facilities where at least half the transits past the well were associated with a CH₄ plume in the downwind direction (50% persistence).”

40. Page 8, Lines 5-8: Please re-write for clarity.

We have reworded this in the manuscript to the following:

“Many previous fugitive emission detection studies do not replicate surveys, but repeated emission detections help build both confidence in detection, as well as statistics about emission severity and persistence through time.”

41. Page 8, Lines 14-17: Please use a consistent theme for capitalization.

We have made changes throughout the manuscript so that all well/facility status and types are capitalized.

42. Page 8, Line 20: Please replace the term “probably” with one with a more scientific connotation or even some statistics.

This was a typographical error. “Probably” was mean to be “probable”, and we have made this change in the manuscript in response to comment from Anonymous Referee #1 p.8, 1.20.

43. Page 8: Please explain, clearly, what each category of wells encompasses. For example, does authorization mean that permit was granted? Was work on the pad started? Was temporary drilling part of the study or as noted previously was it excluded?

We have added the following text to the manuscript to clarify the definitions of these terms where possible. Please also see our reply to Tony Wakelin's comment below concerning certain well statuses.

"The infrastructure inventory we obtained from the provincial regulator identified several statuses of wells including Active, Abandoned, Cancelled, Completed, and Well Authorization Granted (WAG). It should be noted that Cancelled means that the permit for the well has been cancelled, usually before drilling has begun. Similarly, wells with the status of WAG may not have commenced drilling at the time we completed our surveys. However, based on discrepancies noted in the field about abandoned infrastructure, the accuracy of the status information in the inventory database could not always be relied upon. Furthermore, we assumed that test drilling and nearby infrastructure in these locations might serve as potential emission sources as well, so we chose to include wells with these status types in our analysis. A well with a Completed status means that the well drilling was complete, and it was being prepped for production."

44. Page 9, Line 27: 60 out of how many?

The total number of active wells we sampled is listed in Table 2. However, we have added the total (676) to this line in the manuscript.

45. Page 10, Line 2: Please reword "... less emission prone. . ."

We have reworded this line in the manuscript for clarity.

"Infrastructure type is a potential driver of emission patterns, which supports studies that have found large discrepancies in emission factors between valves used in different regions of the US (Allen et al., 2013)."

46. Page 10, Line 20-32: This paragraph does not belong in this section. I suggest either deleting it or moving it to a more appropriate location.

We have left the first line of this paragraph in this section of the manuscript. The rest of the paragraph has been integrated with the final paragraph in section 4 *Conclusion*, and now reads as follows:

"Methane emission reduction strategies for large natural gas developments such as the Montney should focus on first locating super-emitting sites, and then follow up with site-specific emission techniques such as FLIR cameras. This strategy would support LDAR already in place, in a way that would minimize cost to individual operators. It would also focus the attention on the problematic infrastructure and operators, and does not share the cost burden across companies that have already invested heavily in emission reduction technology and leading best practice. It is feasible to detect super-emitters through exhaustive survey campaigns, even ..."

47. Page 12: Please give a more detailed (method definition, details, and statistics) of the setup of your calculations.

Where possible, we have added further details to this section of the manuscript.

However, we feel that the calculations are made clear in Table 2. We did notice a typographical error in the Emission Volume column of Table 2, which has since been amended.

Table 2. Emission volume calculations for all surveyed infrastructure, and also extrapolated to account for all wells and facilities within the BC portion of the Montney formation. Our minimum detection limit (MDL) of 0.59 g/s was used as the emission factor for wells. Facility emission volumes are from Omara et al. (2016) because our sampling from facilities was probabilistic due to emission height variance.

Type	Infrastructure n	Emission Freq (%)	Emission Volume (tonnes/year)	Emission Total (tonnes/year)
Surveyed Wells				
Active	676	47	18.6	5910
Abandoned	228	26	18.6	1103
Cancelled	130	35	18.6	846
Completed	64	30	18.6	357
Surveyed Facilities	265	32	70	5936
Total CH ₄ volume				14152
Montney Wells				
Active	5294	47	18.6	46,280
Abandoned	2149	26	18.6	10,392
Cancelled	1989	35	18.6	12,948
Completed	582	30	18.6	3248
Montney Facilities	1742	32	70	39021
Total CH ₄ volume				111,889

48. Page 13, Line 5: Have the number of wells changed since 2012? Would this affect the calculations in this paper, especially when dealing with the comparison to other sites/studies?

Yes, there was most likely a change in the number of active wells between 2012 and the time these surveys took place in 2015. Unfortunately, the most recent regional CH₄ emission estimate we could find for the area was from 2012. We have added the following text to section 3.4 *Methane Emission Inventory Estimate* of the manuscript to clarify this discrepancy and how it affects our comparison to the provincial estimate.

“It should be noted that the most recent available CH₄ emissions inventory from the province was from 2012, and that increased development and production from the Montney since then may have increased what the regulator would expect to see from this development. However, the 2012 estimate was the most recent applicable emissions estimate we could locate to compare our estimate to.”

49. Page 13: Please add a discussion of possible reasons for the differences in this study and others noted here. Uncertainty range? Different basins? Different measurement approaches?

We have added the following text to explain the differences in measurement

approaches:

“Although airborne measurement techniques are not ideal for locating exact emission sources, they are well-suited to calculate total emission volumes for entire regions so long as other emission sources (such as agriculture) can be accounted for, which they were in the studies listed above. The top-down nature of mobile surveying large amounts of infrastructure allows for a comparison between our CH₄ volume estimate and those of Peischl (2016) and Karion (2015).”

50. Page 13, Line 29: Please give numbers.

We have included the emission frequencies here. This line has been revised to:

“Abandoned wells were also associated with emissions at 26% of the 228 sites we sampled, and we located a group of aging infrastructure (> 50 years old) that was emitting every time we sampled downwind.”

51. Please revise the Conclusion. It needs more specific numbers and information. Also, the addition of super-emitters at the end does not make sense as this paper was not directly making measurements from such sites based on the previously discussed statistics.

To maintain the brevity of the paper we have decided to not include more specific results in the Conclusion. As discussed in response to comment *P14 L9* from Anonymous Referee #2, the mobile survey method is ideal for detecting super-emitters. However, our results were not indicative of the presence of super-emitting sites in the BC Montney, and our results mirror the results found in an independent study by GreenPath Energy (2017).

52. Figure 1: Is it possible to add the location of the wells here as a light gray background? It would be helpful in visualizing the type of routes. Also, please make sure that your designations of routes in this figure and the paper are the same. After reading through, I found TABLE 1 in Tables. Do authors mention this table in the text of the manuscript?

The map scale does not allow for the infrastructure locations to appear as individual points. The routes designations in Figure 1 are correct, and Table 1 is now referred to in the text of the manuscript in the following sections: *2.1 Field Measurements*, and *3 Results and Discussion*.

53. Figure 2: What are 88 industry- defined areas?

We have revised this figure to show the detection distances on each route. Please see response to Anonymous Referee #1 *Figure 2*.

54. Figure 3: This is not a comment on this figure, but in looking at this and other figures, having a table with route numbers, names, and characteristics would be very helpful. Something like Table 1.

This information is included in Table 1.

55. Figure 4: Please revise caption to explain graph better. What are the gray lines?
The gray lines are surveyed roads. This is now explained in the caption.

56. Figure 5: Please re-write caption for clarity. Also, the addition of the uncertainty discussion as noted before, will help this figure.

57. Figure 7: Why are there zero-zero points in this graph? Although physically a zero-zero point makes sense, I do not think the addition of the points is statistically sound. We have re-plotted the regression plots as bar graphs. Please see response to comment from Anonymous Referee #2 Fig. 5,6,7.

58. Figure 9: Please add numbers in the increasing sample size legend. Were any of the wells in this area re-worked? This will change the definition of well age in this discussion. We have not added numbers to the increasing sample size legend because each graph in the figure has a slightly different scale. However, one legend for sample size without numbers is sufficient because it is only meant to show the relative number of times we sampled infrastructure in each category. We did not have information on whether or not wells were re-worked.

Reply to Brian Crosland – SC1

We would like to thank Brian Crosland for his questions about the content of our study. We have addressed both of the comments below. No significant changes were made to the manuscript in response to this review.

Comment 1: -Page 12 Line 20 refers to Omara et al and quotes a "natural gas facility emission volumes of 2.2 g/s". -Reading through the Omara paper it is not immediately clear where this value originates. As per the Omara abstract: "mean facility-level CH₄ emission rate among UNG well pad sites in routine production (18.8 kg/h (95% confidence interval (CI) on the mean of 12.0-26.8 kg/h))" -Note that 18.8 kg / h works out to 5.2 g/s.

-Clouding the issue is a potentially inconsistent definition of "facility". Omara appears to only have measured well pad sites and often refers to them as facilities or "facility-level", eg p.2102 starting just before Figure 1 "Among the routinely producing well pad sites, absolute facility-level CH₄ emission rates varied by more than 3 orders of magnitude..." while the current manuscript appears to differentiate between well pad sites and facilities, where the latter have the potential to emit plumes at heights significantly above the assumed 1m AGL. Can the authors please comment on the origin of the 2.2 g/s value in the Omara paper, as well as clarify the differentiation between "wells" and "facilities" in their manuscript versus the Omara paper.

We will seek to verify the definition of "facility" with Omara and perhaps a corrigendum can be issued that clarifies. We have used the emission rates that we can best tell are accurate for a natural gas facility in our study area without further explanation. Furthermore, as the BC OGC have pointed out in their comment below, many well pads in the area we surveyed have multiple types of

infrastructure (wells and processing facilities) on the same well pad. It is therefore reasonable to assume that Omara's estimate of facility-level emissions is likely a realistic comparison to the locations classified as "facilities" in our study.

Comment 2: Can the authors please comment on their use of a constant emission rate of 0.59 g/s for all well pad sites in light of the text in Omara et al (2016, quoted above) stating that "...absolute facility-level CH₄ emission rates varied by more than 3 orders of magnitude, with UNG sites exhibiting generally higher CH₄ emissions (range: 0.85 ± 0.40 (1 σ) to 92.9 ± 47.5 (1 σ) kg/h) ..." Thank you!

Our CH₄ volume calculation is an estimate of the *minimum* CH₄ emissions in the area. As is outlined in our manuscript, we used emission frequencies of sources that we identified to be emitting persistently. To provide a conservative estimate of emissions, we applied our minimum detection limit to the fraction of persistent emission sources in the area. For this reason we have stated in our paper that our emissions inventory likely underestimates the real total CH₄ emissions for this area.

Reply to Tony Wakelin – SC2

We would like to thank Tony Wakelin from the BC Oil and Gas Commission for his interest in our manuscript. It is helpful to have critical feedback from members of the provincial regulatory organization, as they often have important knowledge about the inner-workings of the local oil and gas industry. We have addressed each comment below, and have included the related edits made to the manuscript.

The British Columbia Oil and Gas Commission (Commission) is the provincial regulator for the oil and gas industry. Depending on the activity the Commission is either the primary regulator, or works with other regulatory agencies to ensure activities are managed for the benefit of British Columbians. In August 2016, the province released the BC Climate Leadership Plan (CLP) which set a goal to reduce methane emissions from the upstream natural gas sector by 45 per cent below 2014 levels by 2025 from extraction and processing infrastructure built before Jan. 1, 2015. The Commission is working with the B.C. Government to determine how to effectively meet this CLP goal.

The Atmospheric Chemistry and Physics discussion paper is of considerable interest to the Commission. Therefore, we have reviewed this discussion paper to determine if the findings agree with the regulator's extensive understanding of the oil and gas sector from the perspectives of protecting public safety, respecting those affected by oil and gas activities, conserving the environment, and supporting resource development.

Relevant to this discussion paper is that the Commission performs 4,000 to 5,000 inspections per year on oil and gas infrastructure and if methane releases are identified

during an inspection, deficiencies are noted and industry is required to take corrective action. Also, routine checks on wells for surface casing vent flow are performed and if significant leaks are found industry is required to take corrective action.

In reviewing this discussion paper, considerable discrepancies were noted between the study findings and the Commission's understanding of oil and gas infrastructure within B.C. Our findings are as follows:

While we appreciate that many inspections are done annually, the nature of these inspections is not clear to us (are they OGI, volumes quantification, or other?), nor are the results of these inspections visible or open to scrutiny in terms of methodology quality control, etc. Furthermore, the relationship between these inspections, and the provincial inventories, is also not clear. Are the inventories updated on the basis of these measurements? While we do know the OGC is very active, and that its people are working in the best interest of environmental protection, we can't measure our study in relation to these inspections because they are neither visible nor open to evaluation.

For reference, in our campaigns we sampled more than 1,740 pieces of infrastructure in triplicate. In other words, we sampled 5,238 locations. This number of "inspections", collected in under a month, is comparable to the BC OGC annual total. The BC OGC might therefore consider mobile surveying as a supplementary way to collect more data on infrastructure (more passes, more visits, or other) with the same amount of effort. Truck pre-screening would allow the OGC to target its use of OGI and other more time-intensive methods, and to use it for emitting infrastructure only – rather than spending considerable effort to find that no emissions exist. Since the BC OGC has legal access to the well pads and facilities in question, its staff members are also in a favourable position to overcome many of the methodological uncertainties that are communicated within their comments. We would always prefer our surveys to be on-pad if possible because a full pass around the infrastructure provides definitive upwind and downwind data - all in close proximity where concentrations are high. We would be happy to assist the BC OGC where necessary to find an optimal balance between measurement methodologies, and we are presently working with operators on projects similar in theme.

Overall:

- **Location of infrastructure:** *The facility data downloaded from the BC Oil and Gas Commission has NTS or DLS coordinates which are accurate to approximately 400 by 400 area. The discussion paper should provide clarity on whether the NTS or DLS locations were used or if and how the study refined the locations.*
We obtained shapefiles with locations of both wells and facilities from the online BC OGC Open Data Portal, which was publicly accessible directly before and after this field campaign took place. Both of these shapefiles (wells and facilities) were projected in BC Albers (ESPG 3005) and recorded as point locations. None of the locations in the infrastructure

inventory we compiled from the BC OGC Open Data Portal used NTS or DLS coordinates. Furthermore, we used aerial imagery to verify point locations, the majority of which were located on well pads. And although we could not verify the identification numbers or statuses of the infrastructure during our mobile surveys, we did verify the locations of infrastructure when it was visible from public roads. For additional information please see our response to comment from Anonymous Referee #1 p9 1.7-8.

- **Emissions attribution:** *There are numerous situations where multiple permits are issued by the Commission at the same general physical location. The discussion paper does not address how this was handled. When a methane plume is detected the discussion paper should indicate how this is attributed to a source when multiple wells and facilities are attributed to the same geographic location. How was a single release anomaly tied to estimating releases that could be tied to multiple permits at the same physical location?*

In section 3.2 *Emission Sources and Trends* we discuss the potential for inaccurately tagging infrastructure as emitting due to the wide radius (500 m) that had to be used because we were surveying from public roads. In this section of the manuscript we clarify that our analysis includes “probable emitting infrastructure, *plus* possibly emitting co-located infrastructure”.

- **Emissions rates may be overstated due to the use of averages:** *In calculating emissions, the STFX/DSF study assumed, even for facilities that had emissions detected just over 50 per cent of the time, that their leak rate was constant and ongoing. The study noted that, especially with venting emissions, the release of methane may not be constant. This assumption has high potential to lead to an overstatement of methane emissions.*

We only included the persistent emission sources we encountered so that we were providing a conservative estimate of CH₄ emission sources in the area. We did not include the episodic emitters in our volume calculations. We combined the fraction of persistent emission sources with our minimum detection limit (g/s) to estimate the total emission volume, which makes it highly likely that this is an underestimation of the total emission volume in the area. Furthermore, we did not include emissions from flowback and liquid unloading, which are likely very large contributors to emissions in an unconventional natural gas development. As described in Allen et al. (2013), these operations have proved to be very large emission sources in these types of developments, but without prior knowledge to when these events were happening we could not include them in our mobile surveys.

Specific discrepancies within the text are as follows:

Page 8 line 22 Well status of:

- *“Cancelled” means the well permit expired without drilling commencing. So these wells do not physically exist in the field and can not be attributed to the release of methane.*
- *“Well Authorization Granted” (WAG) means that a well has been approved, but drilling has not commenced. Therefore these can not be attributed to methane releases.*

In both our field surveys as well as the independent study by the David Suzuki Foundation (which was submitted to the BC OGC), multiple locations with wells and/or facilities that were classified as Abandoned still had infrastructure standing. So it should be noted that the infrastructure status information was not always correct. Please also see our response to comment from Anonymous Referee #1 p9 1.7-8 for revised text we have now included in the manuscript.

Although these emission sources might not have been in place at the time of surveying, we are confident that a persistent plume exists at each of those locations. In the manuscript (Section 3.1 *Measured Gas Signatures*) we are clear that confidence is high for detection of plumes, but comparatively low for geospatial attribution. Plume detection confidence is high in part because of the excess ratio approach, but particularly because of the persistence requirement in this study where an emission must have been observed > 50% of the times it was surveyed, which was normally on different days. The manuscript also already describes how we benchmarked our rate of false positives using a Control route to validate our level of certainty around detection.

Despite our confidence in detection, the attribution of those plumes to known infrastructure during on-road campaigns can be imperfect. Local wind eddies can serve to complicate back-trajectory analysis. Also, emissions originating farther upwind might cause false tagging of a proximal source. The manuscript does already acknowledge that mis-tagging is possible, and we did provide relative confidence values for detection and attribution in section 3.1 *Measured Gas Signatures*.

In response to this comment, we did undertake a new geospatial analysis to search for proximal infrastructure at these Cancelled and WAG locations in question, which numbered only 35 in actual emission inventory calculations. In this analysis we searched for source-types (i.e. possible emission sources in our database) within 3 km. As we expected, there was almost always other infrastructure nearby. Most of the Cancelled and WAG sites were within 1 km of other infrastructure and all but one were within 1.5 km of other infrastructure. We can, in fact, resolve leaks from those distances, given sufficient source strength, and favourable Pasquill stability. In our analysis we had excluded possible sources > 500 m but in these cases it is reasonable

that another nearby source could have been emitting the plumes we observed repeatedly at those locations.

Sources we did not have in our infrastructure inventory may also explain some of the observed plumes. In the region there is an extensive pipeline network that circulates natural gas between pads and facilities. Since we did not include pipelines and associated sources in our study, we therefore implicitly assumed that pipeline, and flow line infrastructural leaks were equal to zero – which is obviously not the case but was a necessary simplification since we did not have these files of these locations. These 'ghost' sources may also explain plumes in these areas where we detected them repeatedly.

To find the actual source of emissions at these locations, we are happy to work with the OGC. As the OGC knows from having accompanied us on surveys in the field, the technique we used excels at localizing emissions quickly - when used for that purpose, and when site clearances are available. We look forward to working with the OGC to help define the source of these emissions and others that may not be resolved well (or quickly) by OGI. An OGI camera is obviously incapable of resolving ground-dispersed emissions such as pipeline leaks, or low-level plumes coming from infrastructure farther upwind – all of which we can detect. We feel that mobile approaches could enhance the efficacy and efficiency of BC OGC measurement and oversight operations, and we look forward to more conversations in the future on the topic.

Page 8 line 23

It is difficult to understand how the text “for the class defined in the databases as Well Authorization Granted, most of which were somewhere in the stages of development during our visits” could be correct. While some wells with a status of WAG would have commenced drilling between the time the well data was acquired in July 2015 and the study completed Sept. 5, 2015, this number is quite small compared to the total number of wells with a status of WAG. While it is unclear when in July 2015 the researchers obtained well data from the Commission, if we assume the data was obtained on July 1, 2015, there were 1,797 wells with a status of WAG. Between July 1, 2015 and Sept. 5, 2015, 146 of these wells commenced drilling. As this data is for all of northeast B.C., a subset of these wells are located in the study area. In any event, a maximum of 8 per cent of WAG wells were somewhere in the stages of development during the field visits and the remaining 92 per cent did not physically exist at the time of the study and therefore were incapable of emitting methane.

In conclusion, for page 8 line 22 the text should be revised from “25% for Cancelled” should indicate no releases from cancelled and “27% for well authorization granted” should read close to zero for well authorization granted.

We have changed the following line in the manuscript:

“We calculated an emission frequency of 26% for Abandoned, 25% for Cancelled, 30% for Completed, and 27% for the class defined in the databases as Well Authorization Granted.”

Please see our response to comment 43. *Page 8* from Anonymous Referee #3 for the text we have added to clarify status type definitions, as well as our explanation for why we included well locations with statuses of Cancelled and WAG.

Page 9, line 5

The text refers to a category of “Undefined”. It should be noted the term “Undefined” is not used to describe the well status (Well Authorization Granted, Drilling, Cased, Completed, Active, Cancelled, Suspended, Abandoned). “Undefined” is used to describe the well operational status (Production, Injection, Disposal, and Observation). For example, a cased well would have an operational status of undefined since it was never completed. In addition, undefined is used for the well fluid type (Gas, Oil, Multiple Gas, Multiple Oil, Multiple Oil and Gas or Water) if a well has not flowed in order to define the fluid type. For example, a well that was completed, but did not flow when tested would have an undefined fluid type. An active water disposal well would have a status of ACTIVE WATER DISPOSAL, not UNDEFINED.

In this section of the text we refer to Figure 6 (Figure 7 in the revised manuscript), which is a plot of the emission frequencies based on operation status (including Production and Undefined wells). We did not include Injection, Disposal, or Observation wells in our emission frequency analysis because our sample size was low. We have revised the text in this section of the manuscript to clarify this and to refer to these descriptions as the operational statuses of the wells.

“A portion of the wells had operational statuses of Production wells, and another portion as Undefined. Only Active Production wells were predictable emitters, with high statistical coherence from route to route (Fig. 7). We did not have a high enough sampling frequency of wells with other operation types (such as Injection, Disposal, and Observation wells) to delineate emission frequencies so we excluded them from the analysis.”

Page 11 Line 11 to 18

The development of the MDL or release rate in the study involves significant uncertainty which is not adequately discussed in the text. Further information should be provided on the laboratory experiments used to determine a mean level of dilution of 70 per cent to demonstrate “realistic field conditions” and should include the range of results from those experiments.

The MDL is established with a standard Gaussian technique similar to that of OTM 33A and others. These methods have been used extensively by industry and academics for nearly half a century. The dilution experiments are extremely straightforward. They consist of exposing the analyser, in a configuration like the field, to different durations of known standard concentration, and to calculate the % dilution. Dilution fraction is a function only of pump rate and cavity size. These analyzers control flow rate extremely closely, and of course cavity size does not change – which means that these offsets are highly repeatable. The process is similar to calibrating a piece of lab equipment – relating peak height to actual concentration under a tightly controlled flow regime. It is a form of calibration that is part of instrument use for an experienced user, and scientific manuscripts will assume that these checks have been done – but these procedures don't generally merit description in the peer review literature.

Page 11, line 19 to 32

NOAA states that the Gaussian dispersion model is recommended as a teaching tool to understand basic concepts and does not recommend its use for dispersion studies. This paper should answer the question as to why this particular model was used when there are a multitude of other dispersion models to choose from.

Regardless of the dispersion model used, a sensitivity analysis should be completed for the main inputs used for the analysis in this study. As currently written, it is unclear which meteorological inputs (wind speed, wind direction, temperature, etc.) the researchers used, and whether they were representative of the region. Dispersion modelling can be highly sensitive to input parameters, and as such a further discussion of this uncertainty should be included, especially as the outputs from this modelling are used to determine as the release rate and to estimate a regional emissions inventory.

In conclusion, for Page 11 (lines 11 to 32), the technique used to develop the emission factor of 0.59 g/s is questionable.

The primary purpose of the paper was to determine emission frequencies, not to create a highly accurate volumetric inventory. In crafting this response we moved to using the Gaussian equations directly, since we have existing projects in which they are being used. They provide the same numbers as the NOAA tool, and while the NOAA tool is useful for teaching because of ease of use, that does not make it inaccurate. In our study we have provided a minimal realistic inventory. The fact that it compares very closely to an independent regulator-commissioned study conducted within a comparable timeframe (GreenPath, 2017), provides validation for our work.

The meteorological inputs for the dispersion model were measurements recorded at 1 Hz frequency by the anemometer on our mobile surveying vehicle. We have added text to section 3.3 *Minimum Detection Limit* to clarify

that these are the values we used as inputs to the dispersion model.

“The NOAA dispersion model computed the mixing depth using the wind speed, wind direction, and weather data we collected from our anemometer at 1 Hz sampling frequency throughout our surveys.”

Page 12, line 20

The term “facility” in the Omara study refers to the sum of wells and equipment at a multi-well site. Facility type as outlined in Figure 8 of this study is not the same as defined in the Omara study. There is no basis for using the emission factor 2.2 g/s in this discussion paper.

Please see our response to Comment 1 from the review by Brian Crosland. We would also be interested in learning the BC OGC’s estimate of facility emissions for the study area.

Conclusion and Recommendation

The fact significant quantities of emissions were attributed to wells that do not exist (i.e. 25 per cent of cancelled wells were reportedly emitting) calls into question the accuracy and validity of the discussion paper. Also, the basis for determining emission factors used in this discussion paper is highly questionable - therefore, this study should not infer that the estimates constitute an emission inventory that could be compared with what is reported under the Greenhouse Gas Emission Reporting Regulation. The Commission would welcome further dialogue to improve this study prior to publication.

We too would like to work together. New proposed Canadian federal regulations strongly move the industry toward measurement (up to 3x annually per piece), and altogether away from estimation models / emissions factors. This will be a change for everyone. In this new scheme, new sources of data (mobile, satellite) will make oversight easier. These tools are evolving rapidly, and inevitable public availability of such data will force more transparency. It will push not only companies, but also regulators, to step up their game as measurement experts. The industry has been relatively dogmatic in its use of monitoring technology, but must look at the new options, of which many good ones already exist. We would offer that the costs of oversight and compliance could be defrayed significantly by combining methodologies in sensible ways – along the way acknowledging the strengths and limitations of these various methods. As a university laboratory, we are available, willing, and eager to help in this type of research. We thank the OGC for its response, and hope we can work together in the near future.

Mobile measurement of methane emissions from natural gas developments in Northeastern British Columbia, Canada

Emmaline Atherton¹, David Risk¹, Chelsea Fougere¹, Martin Lavoie¹, Alex Marshall¹, John Werring², James P. Williams¹, and Christina Minions¹

¹Department of Earth Sciences, St. Francis Xavier University, Antigonish, Nova Scotia, Canada B2G 2W5

²David Suzuki Foundation, Vancouver, British Columbia, Canada V6K 4R8

Correspondence to: Emmaline Atherton (eatherto@stfx.ca)

Abstract. North American leaders recently committed to reducing methane emissions from the oil and gas sector, but information on current emissions from upstream oil and gas developments in Canada are lacking. This study examined the occurrence of methane plumes in an area of unconventional natural gas development in northwestern Canada. In August to September, 2015 we completed almost 8 000 km of vehicle-based survey campaigns on public roads dissecting oil and gas infrastructure, such as well pads and processing facilities. We surveyed six routes 3-6 times each, which brought us past over 1600 unique well pads and facilities managed by more than 50 different operators. To attribute on-road plumes to oil and gas related sources we used gas signatures of residual excess concentrations (anomalies above background) less than 500 m downwind from potential oil and gas emission sources. All results represent emissions greater than our minimum detection limit of 0.59 g/s at our average detection distance (319 m). Unlike many other developments in the US for which methane measurements have been reported recently, the methane concentrations we measured were close to normal atmospheric levels, except inside natural gas plumes. Roughly 47% of Active wells emitted methane-rich plumes above our minimum detection limit. Multiple sites that pre-date the recent unconventional natural gas development were found to be emitting, and we observed that the majority of these older wells were associated with emissions on all survey repeats. We also observed emissions from gas processing facilities of various types that were highly repeatable. Emission patterns in this area were best explained by infrastructure age and type. Extrapolating our results across all oil and gas infrastructure in the Montney area, we estimate that the emission sources we located (emitting at a rate > 0.59 g/s) contribute more than 111,800 tonnes of methane annually to the atmosphere. This value exceeds reported bottom-up estimates of 78,000 tonnes methane for all oil and gas sector sources in British Columbia. Current bottom-up methods for estimating methane emissions do not normally calculate the fraction of emitting oil and gas infrastructure with thorough on-ground measurements. However, this study demonstrates that mobile surveys could provide a more accurate representation of the number of emission sources in an oil and gas development. This study presents the first mobile collection of methane emissions from oil and gas infrastructure in British Columbia, and these results can be used to inform policy development in an era of methane emission reduction efforts.

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1 Introduction

As global energy needs continue to rise, oil and gas operators are increasingly recovering natural gas from less-permeable reservoirs, such as tight sandstone and shale, despite environmental concerns surrounding extraction methods. Unconventional techniques, such as horizontal drilling and multi-stage hydraulic fracturing, can be used to stimulate production of natural gas directly from the source-rock in a petroleum system, ultimately increasing the total quantity of marketable natural gas. Presently, Canada is the fifth-largest producer of natural gas worldwide, with enough unrecovered natural gas to sustain 2013 national consumption levels for 300 years (NEB, 2016). More than 68% of Canada's remaining 1087 trillion cubic feet of marketable natural gas reserves is in unconventional reservoirs (NEB, 2016). By 2035, Canadian natural gas production is predicted to increase 25% above 2013 levels, and this projected growth is largely attributed to unconventional methods of extraction such as horizontal drilling and multi-stage hydraulic fracturing.

Compared to coal, natural gas is often considered to be a preferable fossil fuel because it emits 50-60% less carbon dioxide (CO₂) during combustion (NETL, 2010). As such, natural gas has been deemed a transition fuel on the path to renewable energy because it allows for continued fossil fuel exploitation while seemingly emitting a smaller amount of greenhouse gases. However, the primary component of natural gas is methane (CH₄), a very potent greenhouse gas (GHG), so leaks of natural gas directly to the atmosphere contribute to climate change. The radiative forcing of CH₄ is 30 times that of CO₂ over a 100-year timespan (IPCC, 2014). A recent study suggests that if more than 3.2% of total natural gas production is emitted into the atmosphere during upstream operations, the environmental benefit of combusting natural gas instead of coal or oil, is negated (Alvarez et al., 2012). Therefore, to comprehensively analyze the GHG footprint of different fuel types, it is necessary to consider industrial emissions during upstream operations; these include both vented (intended) and fugitive (unintended) emissions from wells, facilities, and pipelines, during extraction, production, and processing.

"Well-to-wheel" life-cycle assessments (LCA) are a method of comparing the environmental impact of fossil fuels in relation to their carbon emissions. This type of LCA sums all estimated carbon outputs, including emissions during upstream operations, transportation, and combustion. Several recent LCAs suggest that the carbon footprints of unconventional natural gas developments exceed those of conventional natural gas developments (primarily due to emissions during well completions), but that coal developments have the worst overall emissions impact (Hultman et al., 2011; Jiang et al., 2011; Skone, 2011; Stephenson et al., 2011). Contrastingly, another study suggests that conventional natural gas has a slightly higher carbon footprint than unconventional natural gas because of emissions during the liquid unloading process, but that coal remains the fossil fuel with the highest life-cycle carbon emissions (Burnham et al., 2012). A controversial study by Howarth et al. (2011) concluded that a large amount of atmospheric emissions associated with upstream shale gas operations render its environmental impact more severe than coal. This study has been widely disputed for overestimating CH₄ emissions during upstream shale gas processes by not acknowledging that gases emitted during well completions are often flared or controlled by performing reduced emission completions (CNGI et al., 2012). The variability of results from these recent "well-to-wheel" LCAs demonstrates that total upstream emission volumes are difficult to quantify using estimated emission frequencies for infrastructure. It is important to know what percentage of infrastructure is actually emitting, and active detection and measuring techniques are required to

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gain this understanding. Furthermore, it is important to note that emission frequencies may vary between oil and gas developments because of operator best practice, or due to the properties of the geological formation that the hydrocarbons are being extracted from. (In this paper, “development” refers to areas of hydrocarbon extraction, and “infrastructure” refers to oil and gas related infrastructure such as well pads and processing facilities).

The common infrastructural sources of fugitive emissions are poorly understood, particularly in unconventional natural gas developments where these extraction practices are newly implemented. Detection of atmospheric fugitive emissions from up-stream sources has previously been attempted with top-down methods and specific ground-based techniques. Top-down measurements include airborne (Karion et al., 2013; Caulton et al., 2014), and remote sensing (Govindan et al., 2011; Schneising et al., 2014) measurements. These methods often cover large areas in low resolution proving difficult to identify exact sources of emissions. Ground-based techniques, including infrared camera leak inspections (Mitchell et al., 2015), well injection tracers (Mayer et al., 2013), and soil gas sampling (Beaubien et al., 2011; Romanak et al., 2012), are often too labour intensive to be convenient for use in large oil and gas developments.

Although a recent study assumes that around 63% of infrastructure is emitting in the Barnett Shale (Rella et al., 2015), the majority of inventory studies do not report the occurrence of emitting and non-emitting infrastructure. Ultimately, CH₄ management will entail a coordinated targeting of emission sources, and reduction of overall emission frequency. So, studies that build geospatially distributed information on emission frequencies in large populations of infrastructure is a logical next step, because it is the best means of identifying trends across vast developments, behavioural patterns of operators, and the impact of infrastructure age on emission frequency and severity. Mobile screening methods similar to EPA OTM33A (Brantley et al., 2014), even that simply detect emission frequencies, are extremely valuable because emission factors are already available and can be applied uniquely to known emitters so that volumes can be estimated to a reliable degree.

In this study we used a multi-gas (CO₂, CH₄) mobile surveying method that uses ratio-based gas concentration techniques and wind data to detect and attribute on-road CH₄-rich plumes to the infrastructural sources of natural gas developments in northeastern British Columbia, Canada. Our primary interest in this study was to determine the frequency of emissions, and the relationship between emissions and specific classes of infrastructure. We applied this method in an area that is commonly referred to as the Montney, in reference to the extensive, petroleum-rich, geologic formation covering 130,000 km² aerially between British Columbia and Alberta (BC Oil and Gas Commission, 2013). It was first recognized as an unconventional petroleum reservoir in 2007, and attempts at accessing its resources were accomplished with horizontal drilling and multi-stage hydraulic fracturing. These unconventional methods

yielded 4-5 times more natural gas from the Montney formation than conventional techniques that were attempted prior to 2005 (BC Oil and Gas Commission, 2012). Since then, production of BC unconventional natural gas has increased significantly, with the Montney play being the largest contributor (BC Oil and Gas Commission, 2012).

While the Montney is a challenging first target for mobile emissions surveying because of its spatial extent and lack of accessibility (many poor condition roads), it is a sensible first choice given that its emissions have not been measured independently of industry and government, and because the production mode is largely unconventional - and therefore subject to a higher degree of scrutiny. The less permeable, natural-gas hosting portion of the Montney formation is located in BC, a province that has generally been very progressive on many issues of environmental stewardship, so there is a broad interest in emissions

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quantification and environmental performance.

2 Methods

2.1 Field Measurements

Between August 14, 2015 and September 05, 2015 we collected atmospheric gas concentration data along six pre-planned routes in the Montney formation of northeastern BC (Fig. 1). We designed the routes to come as close as possible to a high number of unconventional natural gas wells and their associated processing facilities, while also incorporating a variety of operators and infrastructure age profiles. These were on-road campaigns only, and did not approach well pad infrastructure or facilities.

In total we surveyed 7,965 km of public roads, with an average route length of 248 km (Table 1). We collected gas concentrations at 1 Hz frequency while surveying. The Regional Route and Route 2,3,4 (Fig. 1), dissected natural gas developments containing unconventional natural gas wells. Route 1 targeted an older development in the same area

10 that mainly produces oil; this route was intended for preliminary comparison between conventional oil and unconventional natural gas developments. The Control Route was located outside the perimeter of concentrated natural gas infrastructure, and was intended to act as a control. We surveyed four of the routes (Routes 1, 2, 3, 4) six times throughout the field campaign, and the two remaining routes (Regional Route and Control Route) three times each. We repeated surveys on multiple days to account for varying atmospheric conditions. We also used the repeated survey data to obtain statistics on emission persistence throughout our 23-day survey campaign.

The mobile surveying platform we used to collect these data consisted of an LGR Ultraportable Greenhouse Gas Analyzer (Los Gatos Research Inc., San Jose, CA, USA) Off-Axis Integrated Cavity Output Spectrometer (1 σ instrumental errors of <2 ppb at 1 sec), to measure raw atmospheric concentrations of CO₂, CH₄, and H₂O. A high volume (7 lpm) air pump brought air to the analyzer from the front of the vehicle through 6 mm ID tubing. During post-processing we applied corrections for lag times between the intake filter and the gas analyzers. An NM 150 weather station (New Mountain Innovations, Old Lyme, CT, USA) was located 1.5 meters above the vehicle to collect wind and weather data (with instrumental errors of $\pm 1.5^\circ$ for wind direction and $\pm 4\%$ for wind speed). Gas species concentrations and wind velocity measurements were collected every second while driving. Wind velocity measurements were corrected for both the direction and speed of the vehicle, and we geo-located all data-points using a handheld Garmin GPS. We stored all observations in a database, with processing, statistics, and plots completed in R (R Core Team, 2016).

2.2 Identification of Natural Gas Emissions

Both CO₂ and CH₄ exist, and vary, naturally in the atmosphere. We had to account for this variance in order to identify anomalous measurements that were potentially sourced from natural gas developments. Variation of CO₂ within the survey area was likely primarily a function of oilfield processes (emissions, engines, flares) because there was little industrial activity on the survey routes that was not related to oil and gas development.

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To accommodate the fluctuating background concentrations of CO_2 and CH_4 , the traditional approach would either be for the user to set a concentration threshold above which a reading would be considered an anomaly, or for a dataset minimum value to be used as the background (as in Hurry et al. (2015)). The survey routes in our surveys were multiple hours long each and were often routed through various land use types. For this reason, we did not use the traditional methods of calculating background atmospheric gas concentrations. Instead, we used a simple iterative deconvolution method in which we reset the ambient “background” concentration of each gas at a specified time interval, called the Running Minimum Reset Interval (RMRI), and where we iteratively scaled the RMRI until we had maximized the number of (consecutive multi-point) above-background (“excess”) ratio emission anomalies. In other words, an optimal RMRI was determined for each survey by iteratively applying a suite of RMRI values (60s to 1800s, at an interval of 60s) to our datasets, subtracting the background, and evaluating the number of multipoint $e\text{CO}_2:e\text{CH}_4 < 150$ excursions. As RMRI shortened, a higher number of small emission anomalies were exposed, by about 2-3 times relative to the dataset minimum approach used by Hurry et al. (2016). However, when the iteration approached very small RMRI (<180 s), it consistently caused the total number of anomalies to increase (often by a factor of 10), in particular for anomalies of extremely small concentration. This was expected because when we reset background concentrations too quickly, it overlaps in the temporal domain with instrument and other random noise, causing every departure to seem anomalous relative to the recently reset background. Our algorithms chose the optimal RMRI was taken to be the point at which anomalies were maximized, but also where we avoided the rapid noise-associated increase associated that we saw with extremely short RMRI (Fig. 2). We applied this method separately to each of the 30 surveys for both CO_2 and CH_4 concentrations. RMRI of about 300 s were normally most favourable for the resolution of $e\text{CO}_2:e\text{CH}_4 < 150$ excursions, but for some surveys in more consistent terrain (or weather) longer RMRI proved better. This means that for most surveys, the algorithms reset the background concentration for each gas every ~300 s, to the lowest recorded concentration value during the preceding 300 s. While this background subtraction technique improves the resolution of localized plumes, it should be clear that it impedes the resolution of larger regional anomaly features, or megaplumes, because they may in fact form an artificially elevated background that persists across the 300 s scale. We differentiated occurrences of combustion emissions from other emission sources by filtering out all values where $e\text{CO}_2:e\text{CH}_4 \geq 1000$. Combustion-related emission sources include vehicle tailpipe emissions and industry (ex. power generation).

We identified CH_4 plumes from oil and gas infrastructure in areas where there were multiple successive datapoints of depressed $e\text{CO}_2:e\text{CH}_4$ values. The $\text{CO}_2:\text{CH}_4$ ratio of ambient air is roughly 215, and CH_4 -rich plumes from natural gas sources are substantially more depressed at the point of origin (the Montney does contain some CO_2 in variable, but generally super-ambient, concentrations). We used ratios of these gases in detection instead of raw CH_4 concentrations, because ratios are more conservative than concentrations in valleys and other areas where pooling of gases is common, and fewer false positives are likely. Since fugitive and vented gas sources might be highly diluted in air, their presence will not significantly affect the normal bulk ratio. In this case, the $e\text{CO}_2:e\text{CH}_4$ ratio will record the anomalies with a higher degree of fidelity. This excess $e\text{CO}_2:e\text{CH}_4$ approach has proven to be a useful fingerprinting tool in oil and gas environments because a single ratio value can help elucidate the presence of multiple emission source types. In this study, we follow a procedure similar to Hurry et al. (2016), and a detailed explanation of the method is described there. For our study, we assumed that

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$eCO_2:eCH_4$ ratios < 150 were representative of significant departures from the normal natural ratio, and potentially indicative of an exogenous CH_4 source locally. In order for a natural gas related plume to be identified, we had to detect > 3 successive datapoints with $eCO_2:eCH_4$ ratios < 150.

2.3 Emission Source Attribution

We used publicly available files from the BC Oil and Gas Commission (BC OGC) (acquired July, 2015) of all oil and gas infrastructure in the province to attribute the plumes to potential emission sources based on wind direction and distance. We modified these files to exclude temporary or virtual facilities, such as those in place only during well drilling, or artificial facility entries used to record regulatory information. Otherwise, all in-place oil and gas infrastructure were considered possible emission sources. The infrastructure database included the well and facility locations, as well as various attribute data such as infrastructure types, statuses, and spud dates (drilling dates). In the field, we attempted to verify the locations in the infrastructure database when possible. The locations of the majority of well pads and processing facilities appeared to be accurate, however the statuses in the database may not have been up to date. For example, well pads recorded as “Abandoned” in the database occasionally still had infrastructure present. Although we could not verify the locations of all infrastructure sources from public roads, we assumed based on our experience in the field that infrastructure locations were correct, but that there may be discrepancies in the attribute information. When we detected $eCO_2:eCH_4$ < 150 excursions on-road, and infrastructure was present upwind within the target radius of 500 m, our attribution method flagged that infrastructure as a probable emission source.

We did not use a unique thermogenic tracer to discriminate biogenic CH_4 sources, such as cattle that may have been present on the well sites at the time of surveying. However, repeated surveying of each route increased our confidence that we were tagging stationary natural gas infrastructural sources. Persistence is also an important metric not only for detection, but because many of these fugitive and vented emissions are episodic in nature. Though the infrastructure is stationary, the emissions are not necessarily continuous, and gas migrations, surface casing vent flows, leaks, and tank vents, are all known to have a temporal component. Additionally, maintenance activities may have been occurring onsite at the time of survey, which would generate a non-persistent emission pattern and occasionally we were proximal to drilling or fracturing operations. For this reason, this study does not analyze episodic emission sources, so all infrastructure that we identified as “emitting” should be thought of as continual, persistent, emission sources.

3 Results and Discussion

We collected atmospheric gas concentration data along 30 surveys of six different routes. The routes ranged in length from 200 - 550 km (Table 1), and, at the time of surveying, more than 50 different operators managed the oil and gas infrastructure located on these routes. Compared to some oil developments in western Canada, natural gas developments in northeastern British Columbia are spread out, and therefore required a considerable amount of driving to survey thoroughly. It was not possible to secure a Control Route that was totally free of oil and gas infrastructure, but our Control route did have a density of infrastructure that was much lower than that of other routes, with intervals that were

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3.1 Measured Gas Signatures

Methane was the gas of primary interest for this study, and bulk CH₄ values were in general not appreciably different from background air. Mean CH₄ for the study was 1.897 ppm with $\sigma=0.084$ ppm ($n=444515$). Max and min were 8.148, and 1.819, respectively. Since the background was very stable, anomalies that we detected near oil and gas infrastructure were both obvious, and short-lived. These bulk concentrations contrast with those measured for other developments. For example a study in the Barnett Shale measured a mean CH₄ concentration of 11.99 ppm, with a median of 2.7 ppm, in residential fringes surrounding shale gas development (Rich et al., 2014). The Barnett Shale has about three times as much infrastructure in half the area, but the mean departures in the Barnett exceed the maximum departure in this study. In the Montney, ambient CH₄ concentrations were seldom measurably different than global norms (about 1.850 ppm, but regionally dependent). As a result of the stable background, combined with the deconvolution approach, we were able to use the mobile survey approach to detect the presence of emissions hundreds of metres away from infrastructure. On average, most of our detections were at a mean distance of 319 m from the infrastructure we were sampling (Figure 2), and natural gas emissions were detected at a mean distance of 314 m from the probable emission source.

Figure 4 shows the aggregate (all survey repetitions) kernel density plots of eCO₂:eCH₄ for the survey routes (ratios of CO₂ to CH₄ above ambient). In each density plot, there is a peak near the eCO₂:eCH₄ value 220 which is representative of the ratio between ambient CO₂ and CH₄. Though most of the natural should be filtered out in background subtraction, some of the background signature remains in our datasets during the initial increase and decrease in CH₄-enriched peaks. The kernel density plots in Figure 1 show that, in all of the survey routes except the

Control, we see a population of relatively CH₄-enriched anomalies (less than the natural ratio of 220) that are the result of localized plumes from natural gas development. The Control Route lacked an obvious population of enriched CH₄ values, which was expected because the density of infrastructure was comparatively low.

We used the gas concentrations collected on all three surveys of the Control Route to calculate our probability of falsely detecting a CH₄-enriched plume. To do this, we calculated the fraction of datapoints more than 5 km away from any oil or natural gas infrastructure that our method falsely interpreted to be part of a plume. Using this method we calculated our probability of a falsely detecting a plume on our Control Route to be 0.2%. It should be noted that the Control Route did have other types of industry (such as a pulp mill and active logging) which were not present on the other routes. Therefore, this confidence in plume detection is a conservative calculation that can be applied to all five other routes that we surveyed as a part of this study.

We did not see any CH₄-rich plumes that would be characteristic of a super-emitter. This is evident by the fact that the maximum raw CH₄ value we recorded was low (8.148 ppm). These low emission magnitudes are inline with the results from GreenPath Energy (2017), which used FLIR cameras to assess emission sources in the Alberta portion of the Montney formation.

3.2 Emission Sources and Trends

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Once we classified plumes based on their geochemical signatures, we attributed them to nearby oil and gas infrastructure. An example of this binary result is presented visually in Figure 5, where infrastructure is shown in red when tagged as emitting, or in green when emissions were absent. However, we rarely dealt with the maps directly because our aim was to investigate industry-wide patterns, and drivers, across types and age classes of infrastructure and operators. For further analysis, these binary data were folded into datasets along with infrastructural characteristics extracted from the geospatial databases. While surveys of the Control Route allow us to be very confident about the existence of plumes, we are less confident about the precise origin of the plume. In areas of low infrastructural density, geospatial attribution confidence is maximized. But in areas of high infrastructure density, it is possible that emissions from a suspected source are actually being emitted from a co-located battery, gathering pipeline, or other. A Forward-Looking Infrared (FLIR) camera or other would be required to trace each plume precisely to the source gasket, vent, or soil area, and that work was beyond the scope of this study. Therefore, the following section should be considered as an analysis of probable emitting infrastructure, *plus* possibly emitting co-located associate infrastructure.

Well pads were the most common type of oil and gas infrastructure sampled during our surveys (58% of total infrastructure emission sources). The infrastructure inventory we obtained from the provincial regulator identified several statuses of wells including Active, Abandoned, Canceled, Completed, and Well Authorization Granted (WAG). It should be noted that Cancelled means that the permit for the well has been cancelled, usually before drilling has begun. Similarly, wells with the status of WAG may not have commenced drilling at the time we completed our surveys. However, based on discrepancies we noted in the field about abandoned infrastructure, we could not always rely on the accuracy of the status information in the inventory database. Furthermore, we assumed that test drilling and nearby infrastructure in these locations might serve as potential emission sources, so we chose to include wells with these status types in our analysis. A well with a Completed status means that the drilling was complete and the well was being prepped for production.

As noted earlier, we defined emission persistence in this study as the number of times a CH₄-rich plume was attributed to a piece of infrastructure, divided by the number of times we sampled that infrastructure in the downwind direction. We only attributed a plume to a piece of infrastructure if we recorded three or more successive CH₄-enriched measurements within 500 m in the downwind direction of the source. And, in order for a piece of infrastructure to be classified as an emission source, it had to have > 50% emission persistence. Our technique of background subtraction is tuned to resolve small, localized plumes, but it should be noted that atmospheric conditions have a significant impact on the downwind detectability of emissions. In buoyant and unstable atmospheres, emission plumes will have a tendency to rise, and may not be detected reliably on the ground at distances of several hundreds of metres. As such, we would expect that the probability of detecting emissions on 100% of passes is lower than the probability of detecting emissions on 50% of passes. However, even a figure of 50% persistence (normally detected 2-3 times) indicates that there is high likelihood of a continuous emission at the site, though it might be of small scale which is why we detect it only episodically. Many previous fugitive emission detection studies do not replicate surveys, but repeated emission detections helps both build confidence in detection, as well as statistics about emission severity and persistence through time. Operators and policymakers may find value in these data when prioritizing sites for further investigation, or mitigation.

Figure 6 presents the fractional emissions (emitting/surveyed) for each class of wells that we sampled on all six survey

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routes. We surveyed more Active wells than any other type, and their emission frequency was highest (47%). We sampled Abandoned wells second most, and their emission frequency was 26%. We sampled the remaining classes less often, and their emission frequencies were 25% for Cancelled, 30% for Completed, and 27% for WAG.

While the frequency of emissions from well pads tended to be high, the concentration severity tended to be low. As noted earlier, no concentration above 8.148 ppm was recorded during the surveys themselves. Most of the anomalies were small-scale, and we detected them at roadside as CH₄ excursions on the order of ~0.1 ppm. While there might be appreciable inter-operator variability at the small scale, these sorts of statistics are expected because emissions are related to the type of infrastructure that sits in service, post-fracturing. This infrastructure is of course similar across the entire development, so it should not be surprising that well pads tapping the same formation 100 or 200 km apart might still have similar emission frequencies when the infrastructure of many operators are statistically bundled together. At the large scale, emission frequency might be an inherent property of the development, related to fluid type and handling, needed infrastructure, accessibility, and operator best practice.

A portion of the wells had operational statuses of Production, and the other portion was Undefined. Production wells were predictable emitters, with high statistical coherence from route to route (Fig. 7). We did not have a high enough sampling frequency of wells with other operation types (such as Injection, Disposal, and Observation wells) to calculate reliable emission frequencies so we excluded them from our analysis.

We sampled far fewer facilities than well pads, which was a result of the relative distribution of infrastructure types in this development. Overall, we found 32% of surveyed facilities were correlated with CH₄-rich plumes on >50% of surveys. As shown in Figure 8, Compressor Stations emitted most frequently (70% emission frequency), which we expected based on the results of Omara et al. (2016). However, due to our low sample size relative to well pads, we would need to sample more Compressor Stations to arrive at a statistically significant estimate. Also, these larger compressor facilities may emit from a height significantly higher above ground level than normal well pad infrastructure, which makes emission frequency measurements less reliable,

and certainly conservative. In other developments where the road network allows for fuller transits around such stations at increasing distances, mobile surveying might be a good approach, but in the Montney, accessibility is often limited. In comparison to Compressor Stations, we were able to sample more Shared Facilities, Compressor Dehydrators, and Satellite Batteries, and we observed persistent emissions between 11% and 28%.

Figures 6, 7, and 8 present only anomalies that were repeated on more than 50% of the passes when we were within the target radius of the infrastructure, and downwind. Figure 9 shows the emission persistence of each population of infrastructure type for all repeat surveys. As one moves to the right along the x-axis in Figure 9, emissions are more certain, less episodic, and likely also larger in magnitude – enabling more frequency detection across all atmospheric conditions. In the top left hand panel, it is clear that a group of about 60 out of 676 sampled Active wells were emitting persistently, (100% of the times they were surveyed). In some cases, we detected these emissions on all six survey repeats on different days, and under different weather conditions. As discussed earlier, it was predominantly the Active wells that emitted, at 100% persistence, though several Abandoned and Canceled wells were also highly persistent emitters. We detected emissions from the Undefined well category on an episodic basis. Of all fluid types, we detected the most persistent emissions

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from wells producing Gas, whereas we tagged Oil wells as emitters more episodically. The majority of facilities emitted at 50% persistence, although no facility type dominated this trend. As can be seen from Figure 9, there is also an abundance of infrastructure that emitted at the 25% persistence level.

Our results show that infrastructure type is a potential driver of emission patterns, which supports study that have found large discrepancies in emission factors between valves used in different regions of the US (Allen et al., 2013). We did not have data on the types of equipment used at each well pad, but we did have information on ownership and operator size (via number of sampled pieces of infrastructure), and well age (since spud date). In the Montney, the high number of newer wells emitted less frequently than the small number of older wells (Fig. 10). This is presumably because of improved modern practice, integrity, and better design of new valves, seals, and flange gaskets etc. There was a group of old infrastructure (> 50 years) in the Montney emitting with 100% frequency during our surveys. Infrastructure from larger operators tended to have lower emission frequencies, but this trend is anchored by a small number of small operators with 100% emission

frequency at both 50% and 100% emission persistence. It is important to note that many large operators grow through acquisition of infrastructure that previously belonged to smaller operators. As a consequence they will often inherit the environmental performance of companies whose assets they buy, and it may take some time to bring these sites in line with company expectations, which will skew our interpretations here.

The bottom two plots in Figure 10 show severity of emissions (as measured by eCH_4 at roadside within the anomalies) as a function of well age and operator size. These concentrations are shown "as recorded" and have not been corrected for dilution within the instrument cavity, and are therefore lower than they would have actually been if we were not in motion but stationary within the plume. However, these figures still provide a useful relative index of emission severity. Overall, we see that the older infrastructure (>50 years) has slightly elevated emission severity on-road. We did not note any clear relationship between emission severity and operator size.

As can be seen in Figure 11, there is no geographic trend to the emissions we detected throughout the Montney area; however, it is clear that certain areas, and potentially their associated infrastructure and practices, result in a higher number of emitting pieces of infrastructure (Fig. 11).

3.3 Minimum Detection Limit Analysis

Minimum Detection Limits (MDLs) allow emission detection studies to identify the measuring capabilities of the method being used, and also to understand the minimum emission inventory within a development. Direct source measurement techniques often have lower MDLs than remote survey studies because the measurements are taken at the emission source over a longer period of time and often within a closed bag. For example, a study by Allen et al. (2013), that detected well pad emissions onsite, had an MDL of < 0.001 g/s. Not surprisingly, MDLs for truck-based surveys are lower, as noted in Brantley et al. (2014). In the study by Brantley et al. (2014), they came within an average distance of 57 m of the emission sources and collected data for 10-20 minutes at each site of >0.1 ppm CH_4 . This translated to a MDL of approximately 0.01 g/s. In comparison, we were detecting emissions from farther away (319 m on average), and recorded gas concentration data for < 20 seconds at each site. However, our method of background subtraction and ratio-based plume identification allowed us to detect smaller concentration anomalies with confidence. Since concentrations will decrease exponentially away from a release source, small

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concentrations detected at distance could still represent moderately large emission severity. In order to estimate MDLs for this study, we established MDLs for various detection distances using cavity dilution experiments, followed by dispersion modelling.

Dilution in the instrument's measurement cavity is a function of anomaly duration (plume width, plus transit speed across plumes), and cavity size relative to pump rate. In a laboratory experiment we simulated dilution within the instrument using short injection pulses across a wide range of field conditions. We found that for realistic field conditions, the mean level of dilution was about 70%. In other words, the short pulses resulted in only 30% of the potential concentration deviation. Or, that observed concentrations were on average of 3.3 times lower than the actual ambient concentration that would be observed by a stationary analyzer. This dilution factor must be considered when interpreting our concentration readings at roadside, and also while calculating emission volume estimates. While it would be possible to estimate a MDL for the hundreds of plumes separately, for simplicity we chose instead to focus here on mean MDLs.

Following the dilution experiments, we used the NOAA Air Resources Laboratory Gaussian Dispersion Model (Draxler, 1981) to determine the minimum CH₄ release rate that our mobile method distinguished from ambient at our various plume detection distances (minimum detection distance was 11 m, maximum was 496 m). One main assumption in the model is that the emission release occurred 1 m above ground level (AGL), however it is likely that we encountered varying emission source heights, particularly between wells and facilities. We also assumed the cloud cover to be 50% on all days, and that the cloud ceiling was an average height of 6096 m. The NOAA dispersion model computed the mixing depth using the wind speed, wind direction, and weather data we collected from our anemometer at 1 Hz sampling frequency throughout our surveys. Considering a dilution of 70%, and vertical and horizontal dispersion as simulated by the model under field conditions, we found that these conditions and plume concentrations corresponded to a minimum detection limit (MDL), or release rate, of 0.59 g/s for this study. When we were very close to emission sources (< 60 m), we would have been able to detect emission rates as low as 0.065 g/s (with dilution considered). This exceeded the resolution of Brantley et al. (2014) at a similar distance, though in precision and not accuracy because the stationary techniques of Brantley et al. (2014) are designed to maximize volumetric estimation accuracy. The more precise MDL of our study is simply the consequence of being able to confidently resolve smaller concentration deviations from background using the ratio-based methods.

3.4 Methane Emission Inventory Estimates

Using MDLs for our study, we can reasonably estimate the minimum likely emissions inventory, because it is expected that infrastructural sources with larger emission rates cumulatively contribute the majority of CH₄ emissions (Frankenberg et al., 2016; Mitchell et al., 2015; Rella et al., 2015; Subramanian et al., 2015; Zavala-Araiza et al., 2015). According to a distribution of emissions at a US oil and gas site in the Four Corners region, emissions < 0.2 g/s did not significantly contribute to the overall CH₄ flux rate (Frankenberg et al., 2016). If the US study by Frankenberg et al. (2016) reflects the emission patterns in the Montney, then our mobile method was able to capture the most significant emission sources in the area.

By applying calculated emission rates to the fraction of infrastructure we found to be persistently emitting, we estimated the total volume of CH₄ being released annually from sites emitting at rates above our MDL. Our emission frequency calculation for Active wells (0.47) was very similar to the emission frequency of 0.53 that was recently calculated in the Alberta Montney near Grande Prairie

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(GreenPath Energy, 2017). Our method of calculating emission frequencies is corroborated by this recent FLIR study in the Alberta Montney, which increased our confidence in using our emission frequency calculations to estimate a minimum CH₄ inventory for the development. We used our MDL of 0.59 g/s to represent average emission rates from well pads in the Montney. This value is likely a conservative estimate because it is the smallest value detected at our mean detection distance (319 m), and the majority of our emission detections occurred around this value (Fig. 3). It is also conservative because our method of attribution only considers the wells and facilities that were persistently associated with downwind plumes. It should be noted that this value overestimates emissions for the (small number of) well pads with detection distances < 60 m and emission rates < 0.59 g/s. However, (Brantley et al., 2014) showed that the largest sample population of well pads measured by OTM33A (n=107) had a mean emission rate exceeding 0.59 g/s. As a result, it is reasonable to assume that our MDL serves as a reasonable average emission rate for well pads in a natural gas development, and one that allows us to estimate emission inventories for Montney well pads. For facilities, however, plumes are often emitted from higher above the ground surface, and the high concentration core of those plumes may not descend fully within a few hundred metres horizontal distance, to our 1 m AGL intake. As a result, the emissions we detected from facilities may significantly underestimate total emissions from those sources. For this reason, instead of actual measured MDLs we instead used previously-published natural gas facility emission volumes of 2.2 g/s (Omara et al., 2016), combined with our emission frequency estimates, in order to estimate a total Montney based source inventory.

The minimum reasonable inventory is given in Table 2. Based on the types of infrastructure we surveyed, and their corresponding 50% persistence emission frequencies, we estimate that total CH₄ emissions from the wells we surveyed are 8,216 tonnes per year, and total CH₄ emissions from the facilities we surveyed are 5,936 tonnes per year. We therefore estimate that, in total, there are just over 14,150 tonnes per year of CH₄ emissions from all wells and facilities surveyed in this study. If we extrapolate these values to cover all natural gas wells and facilities in the BC portion of the Montney formation (using infrastructure numbers derived from BCOGC GIS database), that translates to 72,900 tonnes CH₄ per year from wells, and about 39,000 tonnes CH₄ per year from facilities, totalling more than 111,800 tonnes CH₄ per year overall (3,564,000 tonnes per year CO₂e using a 100-year GWP of 30). These measurements and estimates represent emissions from infrastructure emitting > 0.59 g/s from our average detection distance, and are therefore representative of the more significant, higher emitting sites in the area, and not small emissions that would be detectable only at close distance on the well pad. Furthermore, our estimates did not include some well types (including Cased and Drilled) for which our sample size was not large enough to reliably determine emission frequency, nor did it include transport-related emissions, or emissions from well completions. For these reasons, in addition to the measurement limitation imposed by our MDL, our calculations underestimate the actual CH₄ emissions from wells. A comprehensive understanding of emissions in the BC Montney would also involve quantifying emissions below our MDL (< 0.59 g/s), potentially using on-well pad screening surveys with our vehicle, and also onsite techniques to measure smaller emissions.

From all provincial energy sector practices, BC estimates fugitive CH₄ emissions to be 78,000 tonnes per year, and stationary combustion CH₄ emissions to be 17,000 tonnes per year (British Columbia Ministry of Environment (2012)). Our estimated volume of 111,889 tonnes CH₄ per year (solely for infrastructure emitting > 0.59 g/s) suggests that Montney-related natural gas activity contributes more than 117% of this total value for BC. Our calculations are therefore higher than BC's emissions

estimate when we consider that natural gas production from the Montney formation was 55% of BC's total production in 2014 (BC Oil and Gas Commission, 2014) (which would be equivalent to about 52_250 tonnes per year). It should be noted that the most recent available CH₄ emissions inventory from the province was from 2012, and that increased development and production from the Montney since then may have increased what the regulator would expect to see from this development. However, the 2012 estimate was the most recent applicable emissions estimate we could locate to compare our estimate to.

10 Although our CH₄ emission estimates for the Montney exceed the estimates by the BC OGC, they remain lower than recent top-down oil and gas emission studies in the US. For example, in May 2014, Peischl et al. (2016) conducted airborne monitoring surveys of wells that produce more than 97% of North Dakota Bakken formation oil and gas and found that just under 250_000 tonnes of CH₄ were being emitted annually. According to North Dakota state government records, there were 10_892 producing oil and gas wells in North Dakota at the time of the surveys by Peischl et al. (2016). This means that annual CH₄ emissions were
15 an estimated ~23.0 tonnes per well. Similarly, in 2013 Karion et al. (2015) performed airborne surveys over the Barnett shale in Texas and estimated that just over 525_000 tonnes of CH₄ are released annually from this development. Texas state records show that as of early 2013 there were 16_821 producing oil and gas wells accessing the Barnett shale formation, which means that annual CH₄ emissions in this development were ~31.3 tonnes per well. The analogous figure in the Montney is ~7.3 tonnes per well based on our volume estimate. The lower emissions per well in the BC Montney are consistent with the relatively low incidence of excess atmospheric CH₄ in the region on all surveys compared to higher atmospheric CH₄ values recorded in US developments. Although airborne measurement techniques are not ideal for location exact emission sources, they are well suited to calculate total emission volumes for entire regions so long as other emission sources (such as agricultural) can be accounted for, which they were in the studies listed above. The top-down nature of mobile surveys for large amounts of infrastructure allows for a comparison between our CH₄ volume estimate and those of Peischl et al. (2016) and Karion et al. (2013).

4 Conclusion

Unconventional natural gas development in the BC Montney began less than a decade ago, and so the majority of infrastructure is new in comparison to many old conventional oil developments in Alberta and Saskatchewan. Though the Montney is regarded as a young development, there are many locations where old, decommissioned infrastructure exists, and in a generally unkept
25 state. Our results show that older infrastructure is more prone to persistent leaks, albeit at similarly low eCH₄ severity in comparison to younger wells. These results reinforce the need for regulators to pay attention not only to modern equipment, but also legacy wells and infrastructure.

In calculating the frequency of emissions in the BC Montney above our MDL of 0.59 g/s, we found that about 47% of Active wells were emitting. Abandoned wells were also associated with emissions at 26% of the 228 sites we sampled, and we located a group of aging infrastructure (> 50 years old) that was emitting every time we sampled downwind. The emissions we detected from facilities were consistent in both presence and eCH₄ severity, however our mobile detection method is sensitive to plume transport turbulence associated with emissions higher above ground level such as flare stacks.

Our calculated emission frequency values, combined with estimated and pre-established emission factors for wells and

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facilities, provided a CH₄ emission volume estimate of more than 111,800 tonnes per year for the BC portion of the Montney.

This value exceeds the province-wide estimate provided by the government of British Columbia even though the Montney only represents about 55% of BC's total natural gas production. But, in comparison to studies at select US natural gas sites (Peischl et al., 2016; Karion et al., 2015), our results suggest that natural gas activity in the Montney formation may emit both less frequently and less severely than US comparators.

- 5 Methane emission reduction strategies for large natural gas developments such as the Montney should focus on first locating super-emitting sites, and then following up with site-specific emission techniques such as FLIR cameras. This strategy would support LDAR already in place, in a way that would minimize cost to individual operators. It would also focus the attention on the problematic infrastructure and operators, and does not share the cost burden across companies that have already invested heavily in emission reduction technology and leading best practice. It is feasible to detect super-emitters through exhaustive survey campaigns, even from roadside campaigns such as this one. Our results show that a mobile surveying approach for large developments such as the Montney can help to locate probable emitting infrastructure pieces that contribute to the heavy-tailed emission distribution found by Frankenberg et al. (2016). Also, using a mobile survey method
- 10 to define persistently emitting infrastructure allows for the probable emission type (consistent or episodic) to be deduced. Our study highlights the need for emission reduction efforts in the Montney to be focused on the higher-emitting to super-emitting production wells, as well as abandoned, and aging infrastructure.

5 Data availability

Datasets of atmospheric gas concentrations, wind, and temperature data are available upon request. Oil and gas infrastructure location data can be accessed through the BC Oil and Gas Commission Open Data Portal (BC Oil and Gas Commission, n.d.)

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Author contributions. D. Risk and M. Lavoie developed the algorithms for background subtraction and plume detection. E. Atherton designed the field campaigns with insight from J. Werring. E. Atherton, J. Werring, A. Marshall, J.P. Williams, and C. Minions carried out the field surveys. The data were compiled and analyzed by E. Atherton with help from M. Lavoie and C. Fougere. E. Atherton and D. Risk prepared the manuscript.

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Table 1. Survey statistics by Route. Route locations are shown in Figure 1.

Routes	Control	Regional	1	2	3	4	All
Route Length (km)	370	545	145	210	235	280	1785
Number of Repeat Surveys	3	3	6	6	6	6	30
Total km Surveyed	1110	1635	870	1260	1410	1680	7965
Unique Sampled Wells	152	436	172	241	298	182	1481
Unique Sampled Facilities	10	113	63	29	34	16	265
Unique Sampled Groups	49	304	146	88	110	51	748

Table 2. Emission volume calculations for all surveyed infrastructure, and also extrapolated to account for all wells and facilities within the BC portion of the Montney formation. Our minimum detection limit (MDL) of 0.59 g/s was used as the emission factor for wells. Facility emission volumes are from Omara et al. (2016) because our sampling from facilities was probabilistic due to emission height variance.

Type	Emission n	Emission Freq (%)	Emission Volume (tonnes/year)	Emission Total (tonnes/year)
Surveyed Wells				
Active	676	47	18.6	5910
Abandoned	228	26	18.6	1103
Cancelled	130	35	18.6	846
Completed	64	30	18.6	357
Surveyed Facilities	265	32	70	5936
Total CH ₄ volume				14152
Montney Wells				
Active	5294	47	<u>18.6</u>	46280
Abandoned	2149	26	<u>18.6</u>	10392
Cancelled	1989	35	<u>18.6</u>	12948
Completed	582	30	<u>18.6</u>	3248
Montney Facilities	1742	32	70	39021
Total CH ₄ volume				111889

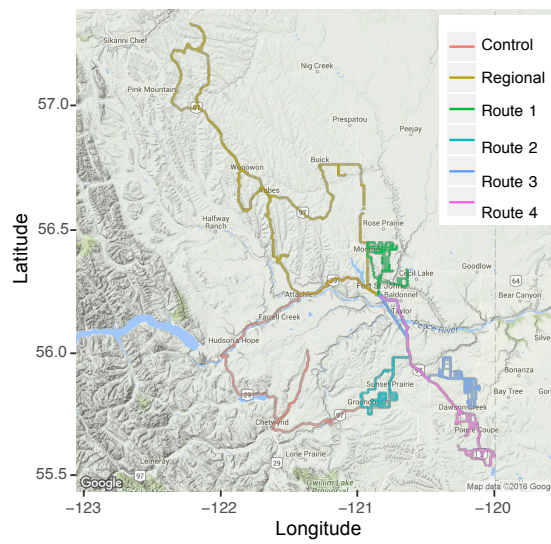


Figure 1. Map of mobile surveying routes. Each route was surveyed six times in August - September, 2015. The Regional Route and Routes 2-4 dissected unconventional natural gas developments. Route 1 surveyed conventional oil. The Control Route was located in an area with a comparatively small amount of oil and gas development, although due to lack of accessible roads in the area it passed by some infrastructure on Route 2 upon returning to the Fort St. John area.

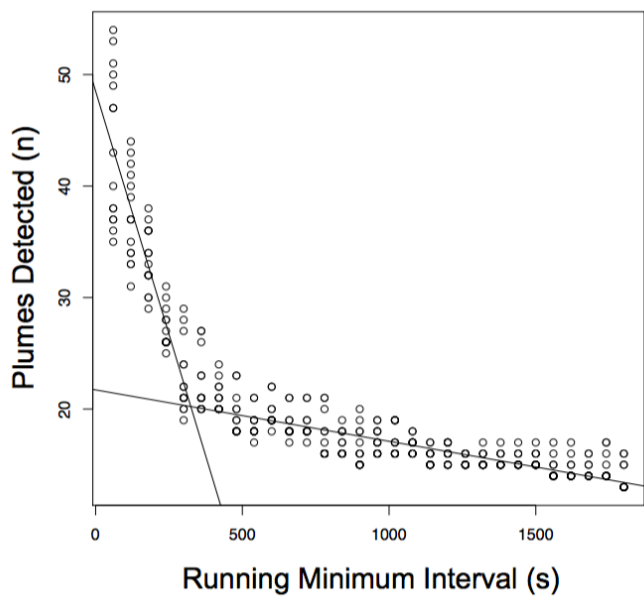


Figure 2. [Example of a regression plot that demonstrates the optimization process we used to calculate an RMRI for each survey. The RMRI for each survey was chosen where the two linear regression lines intersect.](#)

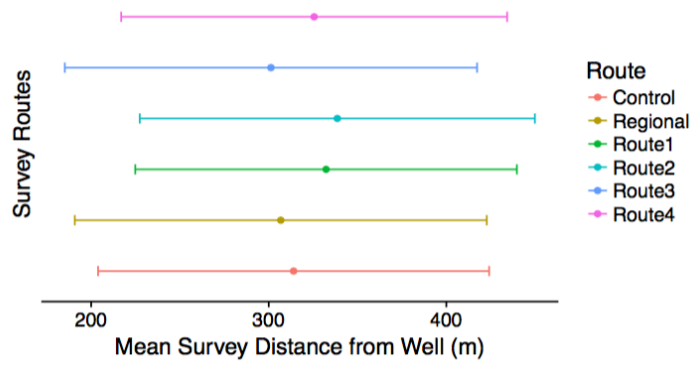


Figure 3. Mean distance from infrastructure while surveying each of the six routes listed in Figure 1. One standard deviation from the mean shows the range of distances at which we were sampling downwind of infrastructure.

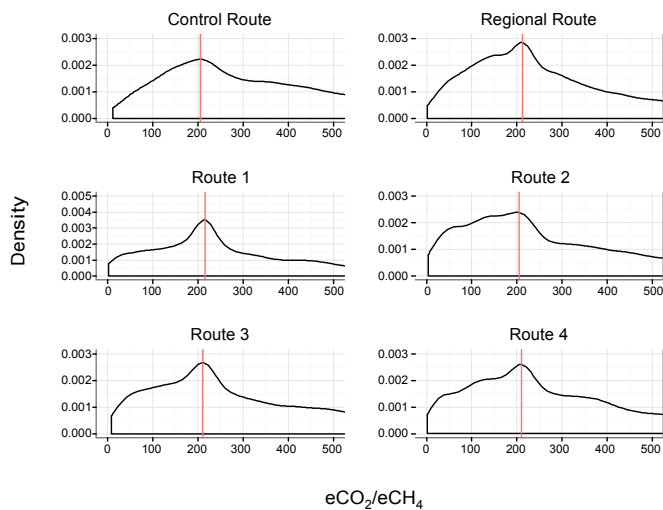


Figure 4. Kernel density plots showing the density of $e\text{CO}_2:e\text{CH}_4$ measurements on each route. Red vertical lines indicate natural $e\text{CO}_2:e\text{CH}_4$ values about 215. Methane-enriched peaks are visible to the left of the natural ratio on all routes except for the Control, where the slope approaches zero with no peaks because substantially less natural gas infrastructure was surveyed. Ratios higher than the natural represent CO_2 -rich plumes which would not be caused by natural gas related emissions, but likely diluted car exhaust fumes, or other industry types.

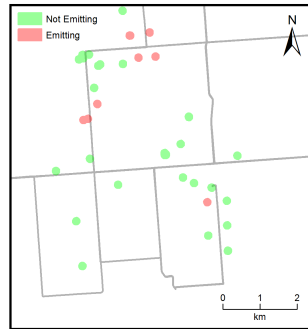


Figure 5. A subset of infrastructure locations that we surveyed during our field campaign in attributed form. This figure serves as an example of how we attributed wells and processing facilities to on-road plumes. Grey lines represent the survey route. In this case 31 wells or facilities were surveyed, and we used our attribution technique, which accounts for wind direction and distance to source, to determine whether or not these wells and processing facilities were probable emission sources.

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Deleted: spatial data in its raw attributed form, extracted from 1 of 30 surveys.

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Deleted: though throughout the whole study almost 1500 wells were surveyed (in triplicate). Using spatial data, along with well or facility characteristics, we were able to infer drivers of emissions in our study area.

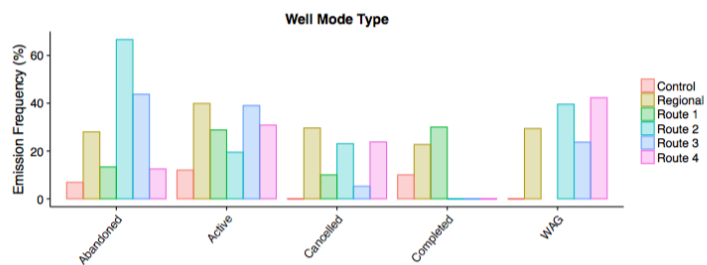


Figure 6. Emission frequencies for each well mode type for all surveyed infrastructure on each route. These emission frequencies were considered in our total emissions inventory calculations.

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Deleted: Well pad emission frequencies for active, suspended, abandoned, and other categories. Each datapoint represents the frequency found on all passes of a single route. Wells were tagged as emitting only when they met the geochemical, geospatial, and persistence criteria.

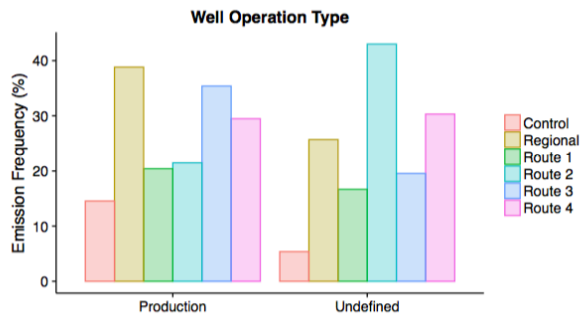


Figure 7. Emission frequencies for each well operation type for all surveyed infrastructure on each route. Certain operation types for which we did not have representative samples are not included (such as Injection and Disposal wells).

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Deleted: Well pad emission frequency for active wells only. As seen by the slope, most of the well emissions are driven by the class of active wells. Almost half of active in-production well pads met our criteria for probable emitters.

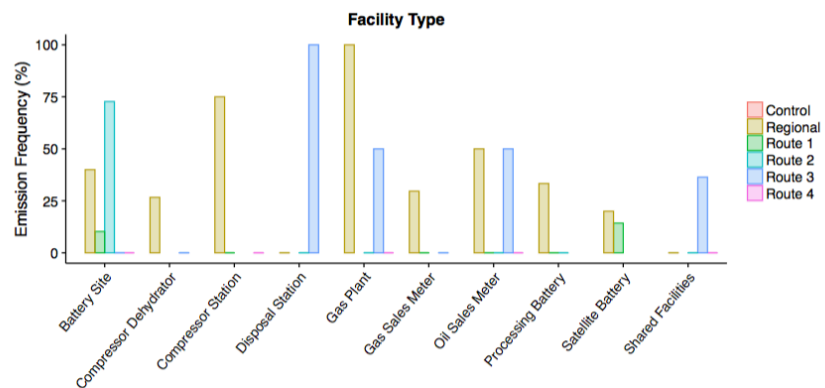


Figure 8. Emission frequencies for each facility type for all surveyed infrastructure on each route. These emission frequencies were considered in our total emission inventory calculations. ▼

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Deleted: all classes of facilities surveyed. Each datapoint represents the frequency found on all passes of a single route. Facilities were tagged as emitting only when they met the geochemical, geospatial, and persistence criteria. Slopes represent the increase in emissions incidence with the increase in number of facilities surveyed.

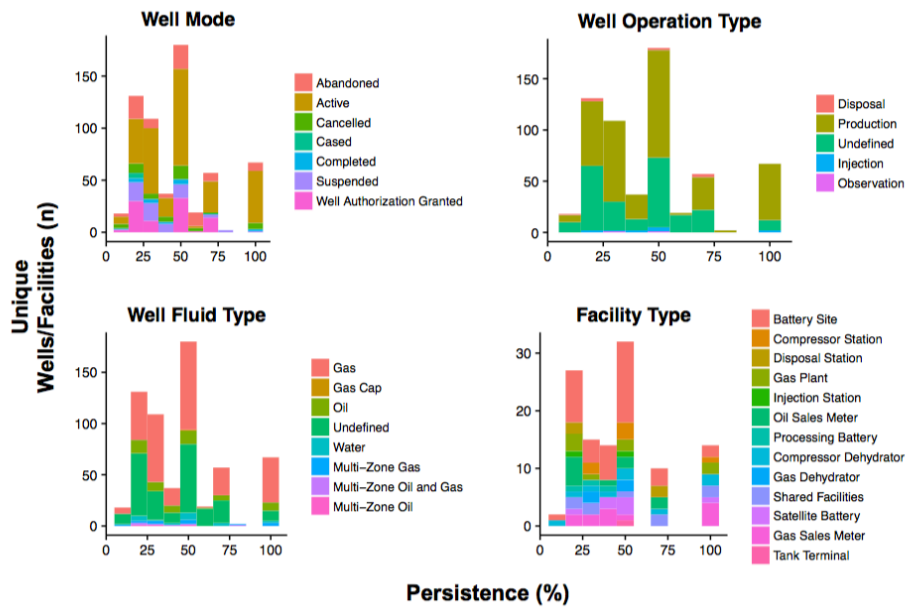


Figure 9. The cumulative number of unique wells/facilities versus emission persistence (%) across all 30 mobile surveys. Persistence refers to the repeated tagging of the infrastructure as a possible emission source based on the method of plume attribution we applied in this study.

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Deleted: Occurrence (number) vs emission Persistence (%) across surveys.

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Deleted: according to criteria on each of the passes when our truck was downwind and could have potentially detected an emission from the infrastructure in question.

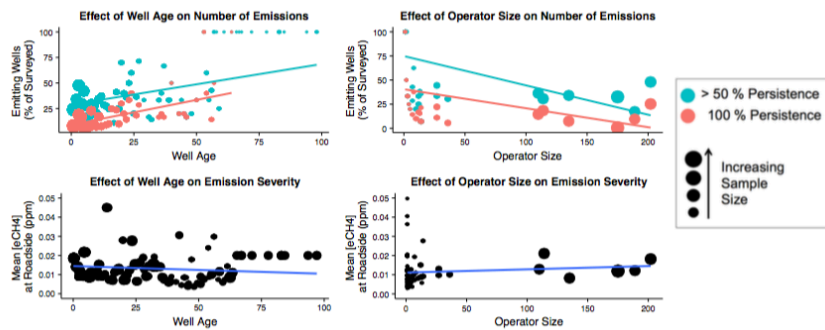


Figure 10. Effect of infrastructure age and operator size on detected emissions. The sizes of the dots represents number of samples taken. Red dots are those recorded at the 100% persistence level, green dots are at 50% persistence.

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Deleted: The grey error bars in the bottom two plots are one standard deviation of the mean of 1) all anomalous datapoints in the radius of wells of each age bin (binned by each year); or, 2) all anomalous datapoints in the radius of each operators' wells.

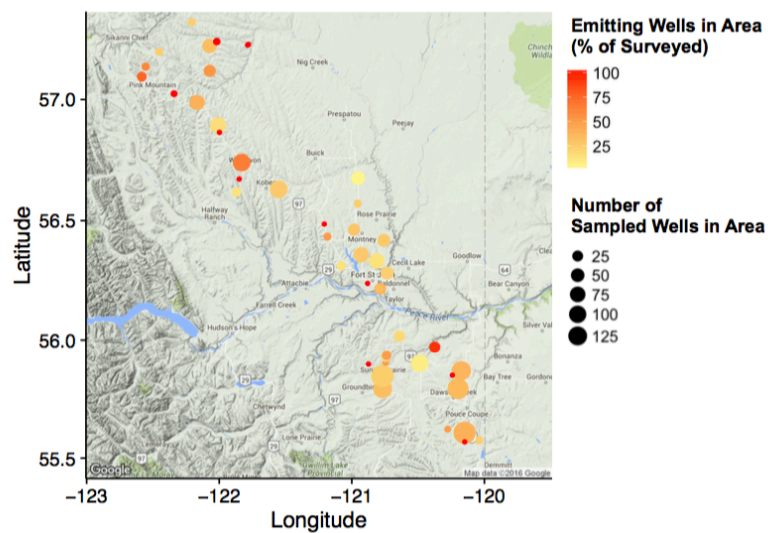


Figure 10. Distribution of emitting infrastructure by industry-defined area. The size of the circles represents the number of measurements we took downwind from individual wells or facilities in each area. The colour of the circles represents the frequency of emitting infrastructure in each area.