Comments on the draft B.C. methane regulations

November 30, 2018

Submitted by: Clean Air Task Force, David Suzuki Foundation, Environmental Defence, Environmental Defense Fund, Pembina Institute

Introduction

Thank you for the opportunity to comment on the consultation draft of the methane regulations for B.C.'s oil and gas sector and for considering the recommendations made in our technical comments submitted on October 15, 2018.

Our recommendations are focused on ensuring that B.C. methane regulations **meet North American best practices and adequately address reported and unreported methane emissions.** The regulations must also align with the B.C. government's brand and desire to have a world-class, balanced and fair climate plan and the cleanest LNG in the world.

As described in our October 15 submission, **a direct measurement study conducted in B.C.'s Montney region found the province's methane emissions are much higher than reported**. This finding is consistent with those of multiple peer-reviewed studies conducted in six basins in the U.S. over the past six years. A recent synthesis paper of these studies concluded that the **majority of these emissions are caused by abnormal operating conditions that occur randomly across a suite of facility types.** The authors of this recent paper, scientists from various academic institutions and non-governmental organizations, concluded that "significant emissions reductions could be achieved by deploying well-designed emission detection and repair systems that are capable of identifying abnormally operating facilities and equipment."[1] A well-designed leak detection and repair system is one that ensures rapid detection of abnormal operating conditions; in other words, a system of continuous leak detection or frequent — e.g., at least three times a year — leak detection.

Several elements of the draft regulations are strong. In particular, we strongly support the zero bleed requirements for new pneumatic controllers contained in Section 52.05(2) and (3) and the three times per year inspection requirement for gas processing plants, compressor stations and multi-well batteries contained in Section 41.1.(2)(a). In addition, we appreciate that the OGC made two changes to strengthen the regulations in the November 15 draft, including the leak detection and repair requirements for a small subset of facilities and venting limits for new tanks. While commendable, these changes are not sufficient bring the regulations up to best practices.

B.C.'s proposed draft methane regulations do not require frequent inspections for the vast majority of oil and gas sites and therefore will not address unexpected leaks. This is not best practice leak detection and repair, and the draft rules fall well short of the ambition set by leading jurisdictions.

We are also concerned that OGC and the B.C. government are not using the most up to date data available, specifically in regards to the equipment count study that was commissioned by the

[1] Alvarez, et al., 3, "Assessment of methane emissions from the U.S. oil and gas supply chain" Science, June 2018, http://science.sciencemag.org/content/early/2018/06/20/science.aar7204.full.

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B.C. and federal governments and that is expected to be available imminently. We expect that the OGC's and B.C. government's current modelling input parameters are inaccurate, therefore it must be noted that **until the data is updated, the B.C. government cannot be confident that the draft regulations will be as effective as the model indicates. This calls into question B.C.'s ability to meet the provincial goal for oil and gas methane reduction, and the equivalence of the draft regulation to the ECCC regulation.**

The David Suzuki Foundation, Pembina Institute, Environmental Defence, Clean Air Task Force and Environmental Defense Fund submit the following comments on the B.C. Oil and Gas Commission's November 15 consultation draft methane regulations and in response to comments raised in the November 19 consultation meeting. These comments are intended to be in addition to our previous technical submission, submitted on October 15, 2018.

Consistent with our prior comments, and as set forth in additional detail below, we urge the OGC to make the following improvements to the methane regulations:

- Leak detection and repair
    - Increase the frequency of comprehensive surveys to three times per year for all single well batteries, multi-well facilities and single conventional and unconventional well sites if those sites contain a tank, unless emissions from the tank are not controlled *and* the site does not sell gas.
    - All remaining facilities should be subject to compreshensive surveys, rather than ineffective "screenings," at least once per year.
    - Only sites with no other equipment besides a single wellhead, gathering pipelines, and meters should be exempted from the comprehensive surveys requirement, consistent with the ECCC rule.
- Venting limits for existing tanks
    - Require the same venting limit for existing tanks as for new tanks.

Leak detection and repair

Controlled and uncontrolled tanks

The current draft regulation added single well batteries with controlled tanks to the facilities covered by the three times a year LDAR requirement. While we appreciate this update, we note that according to the facility count data provided by the OGC, there are only 98 single well batteries in B.C., and we believe only a small number of those have controlled tanks. This compares with thousands of single-well facilities. Accordingly, the current three times per year

LDAR requirement will still exclude a large majority (at least 92 per cent in 2025)[2] of facilities. In contrast, the Environment and Climate Change Canada regulations would require three times per year inspections at essentially all oil and gas sites in B.C.[3]

As we have communicated previously, there is ample evidence that storage tanks are associated with many leaks and occurances of improper venting. We therefore urge the OGC to extend the three times per year LDAR requirement to any facility with a tank, with the exception of sites with uncontrolled tanks that do not sell any natural gas (at these sites, gas may be directed to vent from the tank, so there is little value in addressing a leak). This should apply regardless of site designation: any site, except those described above, should be subject to frequent inspection. Given the errors in site designation noted in the literature for B.C. oil and gas sites, and the very low number of batteries in the B.C. facility counts, it is very likely that some B.C. well production facilities that are not designated as "batteries" contain tanks. As we noted in our previous submission, the B.C. definition of "wells" notes that tanks may be present at well facilities.

While we are aware of the argument that uncontrolled tanks benefit less from LDAR as they are designed to vent, this misses two key points. First, at production sites that capture natural gas, improperly operating dump valves on separators can result in excessive venting from tanks, including uncontrolled tanks. This is because an improperly operating dump valve can result in natural gas being routed to the uncontrolled tank rather than the sales line. The excess venting that occurs is a source of emissions as well as wasted product. The separator itself if a source of significant leak and improper operations emissions, such as problems that result from malfunctioning or poorly tuned level controllers.

Single and multi-well sites

We recommend increasing LDAR frequency to three times per year for any site that consists of multiple conventional or unconventional wellheads, even if tanks are not present at the site. A facility that consists of multiple wellheads should be considered a multi-well facility. To disaggregate wellheads that are collocated at a single site and count each wellhead as a single well for the purpose of an LDAR program flies in the face of efficient and logical environmental

[2] Based on data from BCOGC. If all single-well batteries have controlled tanks and would therefore be subject to 3x per year LDAR (an unrealistic assumption, since tank controls are not common in B.C.), then 8% of upstream sites would be subject to 3x per year LDAR. If very few SWBs have controlled thanks the figure would be 7% (consistent with the figures in our earlier submission, prepared prior to the introduction of the provision increasing LDAR frequencies at SWBs with controlled tanks).

[3] ECCC rules require 3x per year LDAR inspections at any upstream site producing 60,000 cubic meters or more per year, with the exception of wells sites which contain no other equipment aside from a single wellhead, gathering pipelines, and associated meters. Based on our analysis of DI Desktop data, we believe that essentially all sites in B.C. produce at least 60,000 m^3 of gas. We believe that there are very few sites in B.C. with just a single wellhead, pipelines, and meters (*without separation*).

protection. The presence of multiple wellheads in one location increases the number of components that may leak. Yet, a scan of the entire facility using an OGI can quickly and efficiently detect leaks from all wellheads, meaning the survey cost per well is considerably lower. As a result, LDAR is very cost-effective at multi-well facilities. We are not aware of any other jurisdiction that considers each individual wellhead at a facility as a separate well for purposes of LDAR, and strongly urge the OGC to require three times a year inspections at all such well facilities.

Equipment counts

As we described in our earlier submission, OGC is using a model of leak emissions that greatly underestimates leak emissions from well sites, because OGC's model sites have far too few components at these sites. For example, based on the data OGC provided to stakeholders in late September, for single well production gas facilities, the B.C. model assumes that the site has a total of six valves and 19 connectors (no open-ended lines or pressure relief values) in gas service, and a single connector in liquid service. As we discussed in the earlier submission, this may be a credible estimate of the number of components on a wellhead, but it is *not* a credible estimate of the number of components at a SWP *site*. Indeed, the component count for a SWP gas site appears to originate from a schedule of component counts for various types of *equipment* at upstream sites assembled in a 2005 Canadian Association of Petroleum Producers report. The CAPP report schedule, which is reproduced in Table 12 of a 2014 CAPP report,[4] lists precisely the same components used by OGC for a gas SWP site count, for a deep (> 1000 m) gas well. In the CAPP component schedule, other equipment that is typically present at B.C. SWP facilities, such as meters and separators, are listed separately, but the OGC component count for a gas SWP site does *not* include the components in those pieces of equiment for those sites.

Optimal survey frequency

In response to questions regarding the optimal survey frequency raised by the OGC at the November 20, 2018, meeting, we reiterate our position that frequent, if not continuous, leak inspections are critical to prompt discovery of abnormal operating conditions that can cause very significant emissions. The underlying support for this is as follows:

Science and regulatory inspections have demonstrated that abnormal operating conditions are responsible for excess emissions[5]; rapid detection and remediation of such conditions are critical to mitigating these releases.[6] As discussed in our October submission, inspections done by the Colorado Air Pollution Control Division and U.S. EPA of well production sites revealed very significant excess emissions caused by improper design and operation at these

[4] See https://www.capp.ca/publications-and-statistics/publications/238773, Table 12.
[5] Alvarez; see also EPA and CO Consent Decrees discussed in NGO October submission.
[6] Alvarez, 2018

sites. For example, if one flare goes out at a controlled storage tank, this one "leak" will lead to uncontrolled venting and excess emissions. These emissions can be quite significant. The longer this leak goes undetected, the more pollution it causes. These inspections led to the imposition of millions of dollars in fines to operators as well as regulatory reform. A key aspect of the regulatory reform is Colorado's inspection requirement for well production facilities that includes monthly and quarterly inspections for facilities with high potential emissions.

LDAR is effective at detecting abnormal operating conditions such as improperly operating tank controls or malfunctioning pneumatic controllers. The Colorado Air Pollution Control Division conducted IR camera inspections at over 8,000 locations between 2013 and 2015. The Division reports a significant decrease in observable leaks and unintentional venting: in year one, the Division observed leaks and unintentional venting from 42 per cent of facilities whereas only nine per cent of facilities had leaks/unintentional venting in the last inspection conducted two years later. The Division found that the project was effective at reducing unintentional venting and leaks, helped operators identify problems that led to such leaks and venting, and drove voluntary improvements intended to help prevent and identify leaks. According to the Division:

> "The most direct impact of the project, although not fully quantifiable, is the immediate reduction or minimization of emissions to the atmosphere from well production facilities through timely notification and repair of identified sources of leaks and venting."
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> "The project was also useful in helping identify atypical or previously unknown issues, such as cracked tanks, flare fuel gas line leaks (underground emanating to surface), separator pressure relief venting (indicative of separator unable to overcome high gathering line pressure), as well as malfunctioning equipment designed to vent (pneumatic devices)."
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> "Affected O&G operators/companies reported purchasing or increasing the use of IR cameras to find and prevent leaks/venting, transitioning to better materials or equipment (such as higher quality thief hatch seals/gaskets and PRVs), implementing best practices to help prevent leaks/venting, and focusing on tank system design and operations analysis."[7]

Even though the greatest number of leaks are discovered during the first inspection at a facility, operators continue to find leaks over time. Because emissions from these leaks can be significant, ongoing, frequent inspections are critical to maintaining a properly functioning and leak- or near-leak-free facility.

Colorado regulators considered information related to the optimal survey frequency in 2014

[7] CO Dept. of Public Health & Envn't APCD, Colorado Optical Gas Imaging Infrared Camera Pilot Project: Final Assessment, https://www.colorado.gov/pacific/sites/default/files/APCD_IRCameraProject_FinalAssessment.pdf

when adopting the state's methane rule. Colorado's rule, which requires ongoing monthly, quarterly or annual inspection at the majority of facilities, had the support of three large oil and gas producers: Noble Energy, Anadarko Petroleum Corporation and Encana. Notably, Encana submitted testimony regarding its own voluntary LDAR program, which requires monthly instrument-based inspections. According to the company, "Encana's experience shows leaks continued to be detected well into the established LDAR program."[8]

Other information presented during the Colorado rulemaking further supports the need for frequent inspections over time. During the rulemaking, industry opponents of Colorado's rule submitted data collected from their own LDAR monitoring experience. These data demonstrated an initial component leak rate frequency (leaks existing before the LDAR program was initiated, identified in the first LDAR inspection) at new and modified gas processing plants of 1.7 per cent.[9] The observed leak rate frequency falls to 0.4 per cent after the first monitoring period. A second analysis, at another set of plants where LDAR programs had been in place for some time before the data collection began, found that at these plants the leak frequency averaged 0.3 per cent over 12 consecutive calendar quarters. These results show the effectiveness of the LDAR program. While the observed leak rate does decline after the first monitoring period, the data evidence a steady state of leak detection after that. If LDAR were discontinued, of course, the leak rate would eventually rebound to the higher, pre-LDAR rate.

The successor to Encana's operations in Wyoming, Jonah Energy, has also expressed its support of at least quarterly instrument-based inspections. Jonah Energy supports the WY DEQ's quarterly instrument-based LDAR program for existing well sites, noting that it already complies with the proposal as "each month, Jonah Energy conducts infrared camera surveys using a FLIR camera at each of our production facility locations."[10] According to Jonah, "the estimated gas savings from the repair of leaks identified often exceeds the labor and material cost of repairing the identified leaks" while also significantly reducing pollution.

A report prepared by Carbon Limit for the Clean Air Task Force, based largely on data from Canadian facilites, is in accord. This report shows that frequent LDAR is very cost-effective at well and battery facilities, even with frequent (quarterly or semi-annual) inspections. Carbon Limits actually found that semi-annual LDAR at these facilities would have a negative net cost,

[8] Rebuttal Statement of Encana Oil and Gas (USA) Inc., p. 10, Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3,7 and 9., on file with EDF.

[9] Prehearing Statement of WPX Energy Rocky Mountain, LLC'S AND WPX Energy Production LLC, Ex. A, Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3,7 and 9., on file with EDF.

[10] Comments submitted to Mr. Steven A. Dietrich from Jonah Energy LLC on Proposed Regulation WAQSR, Chapter 8, Nonattainment Area Regulations, Section 6, Upper Green River Basin Permit by Rule for Existing Sources (April 13, 2015), available at http://deq.wyoming.gov/aqd/rule-development/resources/proposed-rules-and-regulations/.

because the additional revenue from selling gas that was leaking before the inpection could pay for the cost of the program. Carbon Limits found that an LDAR program with quarterly inspections at these facilities would have a net cost to operators of $143 per to of methane pollution abatement.[11]

We urge the OGC to follow leading jurisdictions in the U.S. (i.e., Colorado, Wyoming and California) and Mexico, which require frequent — at least three times a year — inspections at all facilities other than those that consist solely of stand-alone wellheads and associated meters and/or gathering lines.

Weather considerations

We strongly oppose the suggestion made at the November 19 consultation meeting that climate and poor road conditions pose unsurmountable obstacles to conducting LDAR at sites during winter. First, to the extent that weather or other access conditions pose site access challenges, our proposal already accounts for such conditions since we advocate for inspections three times a year. Thus, operators have flexibility to conduct inspections when site access is available. Second, best practice from other jurisdictions demonstrates that climate and access conditions have not justified significantly lower survey frequency.

ECCC set a three times per year inspection frequency to account for operational difficulties in winter months. This concern has been raised in other jurisdictions with challenging winters, but we believe this is not supported by the record. Oil and gas wells do not generally remain unmanned for the winter. Colorado requires that operators inspect for and repair leaks at compressor stations, well sites and storage tank batteries. The rules require quarterly or monthly inspections at mid-size and large facilities, respectively.[12] Statewide, more than 3,900 well facilities and compressor stations are subject to quarterly or monthly inspections, including 491 well facilities outside the Denver basin (these are primarily in mountainous areas in western Colorado).[13] During the process while the state was drafting these rules, operators on the western slope made a similar argument to the one made by industry in Canada, asserting that they needed an exception because they could not access all their facilities in winter.[14] However, the record shows operator visits to wellpads are frequent, even in winter months. Operators visit facilities

[11] See Carbon Limits (2014), "Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras," at figure 12. Report available here: https://www.catf.us/wp-content/uploads/2014/03/CATF_Pub_CarbonLimitsLDAR.pdf.

[12] Colorado 5 C.C.R. 1001-9, Reg. 7, § XVII.F.4.a.

[13] Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (Feb. 7, 2014) Tables 33 and 24. Available at: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573.

[14] Rebuttal Prehearing Statement Of The Sierra Club, Natural Resources Defense Council, Earthworks Oil And Gas Accountability Project And Wildearth Guardians. Before The Colorado Air Quality Control Commission. Pg. 13. Ex. 8.

monthly for AVO inspections, and in some cases daily for service, maintenance and workovers.[15] The Colorado Air Pollution Control Division concluded that inspection frequencies would remain unchanged, but operators could request to delay leak repair if winter weather made the repair unsafe.[16]

Wyoming requires quarterly instrument-based inspections at all new and existing well sites in its remote Upper Green River Basin with the potential to emit four tons of VOCs from fugitive components.[17] As describe above, Jonah Energy, the largest operator in the Upper Green conducts *monthly* inspections of its wells in that basin.

In Alberta, Directive 055 requires monthly visual inspections of tanks, and there is no evidence of lack of access in the winter.[18]

Western Colorado, Alberta and the Upper Green River basin in Wyoming all have harsh winters, but operators have been able to conduct inspections without significant issues arising in the years since these rules/programs were put in place. Operators go to almost all sites regularly, and there is no evidence that there are major limitations with accessing most sites in winter.

U.S. EPA also recognized the issue of challenging winter weather. For compressor stations, where U.S. EPA requires quarterly LDAR, EPA waives the requirement for at most one quarterly inspection per year in areas where the average temperature for a calendar month is below 0 F for two of the three months of the quarter.[19]

We urge OGC to consult with firms providing LDAR services in Canada on the feasibility of LDAR in B.C. during winter months. These firms have real-world experience in these matters; it is our understanding that the firms are not dormant in the winter. If OGC remains concerned about access to the most remote facilities, OGC should consult with stakeholders about a targeted, narrow exemption for truly remote sites.

[15] Ibid.

[16] Colorado 5 C.C.R. 1001-9, Reg. 7. See pg. 142. "Importantly, the Commission does not intend to allow owners or operators to delay required monitoring for the entire winter season."

[17] WY Permitting Guidance; Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6.

[18] Alberta Energy Regulator. Directive 055. Table 2. Available at: https://www.aer.ca/documents/directives/Directive055.pdf

[19] 40 CFR §60.5397a(g)(5).

LDAR at conventional well sites

We also strongly oppose the suggestion made at the November 19 consultation meeting that requiring LDAR at conventional well production sites is less important because the population of conventional well sites in B.C. is declining at a rapid rate. Currently, there are almost 6,000 convention single well production sites (including gas and oil sites) in B.C. that the draft rule would only subject to annual, non-instrumented screening. While this population has certainly declined over recent years, OGC should not set policy based on an assumption that the number of sites will decline at such a rate as to make leaks from conventional sites trivial in the near future. Indeed, the number of conventional oil wells has only declined by ~15 per cent over the past five years, and OGC's projections estimate that about 3,500 conventional oil and gas sites will still be operating in 2025, when the draft LDAR rules would be in effect. As we described in our earlier submission, there is ample evidence that these conventional sites have significant emissions; they simply shouldn't be exempted from modern inspections, as the draft regulations would do.

Lastly, we strongly urge the OGC to include a clear pathway for the use and approval of alternative leak detection methods in the language of the rule. At the meeting we heard that the OGC intends to allow operators to request approval to use alternative LDAR methods, consistent with the ECCC approach. We support the ECCC approach, and support the OGC allowing for a similar process. However, the current consultation draft does not include any language that allows for the use of alternative leak detection methods, and we strongly urge the OGC to include such language in order to provide clear instructions for the regulated community, vendors of alternative technologies and the public.

Tank venting limits

The November 15 consultation draft introduced a tank venting limit of 1,250 m^3 for new tanks. While this is commendable, the same tank venting limit should also be applied to existing tanks. Having different tank venting limits for new and existing productions is inconsistent with best practices in every leading jurisdiction, which require the same venting limit for both (Canada, Colorado, Wyoming, California, Mexico).

In the November 20 consultation meeting it was suggested that it would be too costly to impose a stronger venting limit on existing tanks. However, analysis of the data on the cost of retrofitted controls for tanks shows that controls for methane on tanks are cost-effective at the emissions limits far below the 9,000 m^3/month that OGC has proposed in the draft regulation. In fact, these controls are cost-effective at the 1,250 m^3/month limit that ECCC uses and OGC has proposed for new tanks in the draft regulation. Based on cost figures from the California Air Resources Board and the Colorado Department of Public Health and Environment, the annualized cost of installing and operating a vapour recovery unit at a tank ranges between US$11,995 and

$22,709, while the annualized cost of a flare is US$6,287.[20] Notably, these cost estimates were developed for existing-source regulations, so they are estimates of costs for retrofits. (Clearly, capturing gas with a VRU and directing it to a gathering pipeline is far superior to flaring gas, which wastefully produces carbon dioxide and other pollutants. However, by converting methane to carbon dioxide, flaring is much less harmful than venting, and recognizing that some facilities do not have gathering pipelines available, we focus this discussion on flaring as it is a generally applicable control.)

Exhibit X is a spreadsheet that can be used to calculate the cost effectiveness controlling tank emissions with VRUs or flares at various tank vent thresholds. At thresholds far below the 9,000 m^3/month threshold for existing tanks in the draft B.C. rule, abatement is highly cost-effective. For example, at a threshold of 2,000 m^3/month, the abatement cost associated with a flare is CAN$35 per metric ton CO_2e.[21] VRUs have higher costs, but still are cost effective at thresholds well below 9,000 m^3/month: At a threshold of 4,000 m^3/month, the net abatement cost of operating a VRU is CAN$49 per metric ton CO_2e.[22] We note that the cost calculated at the threshold would actually be the highest per-ton cost imposed under a rule requiring control for tanks emitting over the threshold, since the regulation would result in controls on tanks emitting at levels higher than the threshold, and those tanks have lower per-ton abatement costs than the tanks right at the threshold.

We also note that this aspect of the draft B.C. regulation is weaker, compared to the ECCC rule, because of the different structure used in the B.C. regulation. Section 26 of the ECCC rule applies a venting limit of 1,250 m^3/month to venting from upstream sites.[23] This includes venting of gas from tanks, *and* surface casing vent flows.[24] In contrast, the draft B.C. rule allows operators to vent 1,250 m^3/month from tanks at new sites, 9,000 m^3/month from tanks at existing sites, and 3,000 m^3/month from SCVF. Clearly, the draft B.C. regulation is far weaker than the ECCC rule and would needlessly allow venting that could be reduced or eliminated at very low cost.

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[20] CARB Economic Analysis: https://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20Appx%20B%20Economic%20Analysis.pdf
CDPHE Cost-Benefit Analysis: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573

[21] Assumes 98% of methane consumed in flare, 1 CAD = 0.77 USD, and methane GWP of 25. See Tank spreadsheet (Exhibit X).

[22] Using the assumptions stated in the previous footnote, CAD$3 for the value of conserved gas sold by the operator, and the higher annualized cost for a VRU (US$22,709 per year).

[23] The ECCC vent limits apply to any upstream site producing 60,000 cubic meters or more per year. As noted above (currently footnote 3), based on our analysis of DI Desktop data, we believe that essentially all sites in B.C. produce at least 60,000 m^3 of gas.

[24] Section 26(2) lists to the sources of venting from sites that are *not* included in the ECCC venting site limit – liquids unloading, blowdowns, dehydrators, pneumatic equipment, startup and shutdown venting, completions, and venting for safety purposes. Since SCVF is not included in this list, any SCVF volumes are counted against the ECCC site limit.

Lastly, it was suggested that the emissions from tanks in B.C. is small, and that an emphasis on existing tank limits is unwarranted. As we described in our October submission, data from the U.S. demonstrate that storage tanks, including controlled tanks, are responsible for excess emissions due to abnormal operating conditions in multiple jurisdictions. We therefore question the accuracy of the B.C. inventory in so far as it estimates low tank emissions. Achieving B.C.'s 2030 climate targets will be challenging, especially with increasing natural gas and LNG development. As such, no cost-effective solutions should be left on the table, as forgoing these reductions will require reductions at materially higher costs in other sectors of the economy.