Reducing methane emissions from B.C.'s oil and gas sector

Coalition comments and recommendations

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Recommendations

1. Set stronger standards that come into force early including:

a) Stronger venting and flaring rules

b) Lower tank emissions limits

c) Stronger leak detection and repair requirements (LDAR) rules including monthly, comprehensive instrument-based LDAR

d) Allowing alternative LDAR pathways

e) Consider developing an independent, centralized, and provincial measurement-based LDAR program

f) Requiring zero emitting pneumatic equipment

g) More robust compliance and enforcement programs including a super emitter response program and enforcement using current aerial measurement campaigns

h) More detailed and measurement-based emissions reporting

i) Lower limits for compressor emissions and controls for engine exhaust

2. Accelerate the timeline for near-zero oil and gas methane emissions to 2030

Thank you for the opportunity to provide comments on the development of new policy to meet and exceed B.C.'s commitment to reduce methane emissions.

We commend B.C.'s continued efforts to better understand and characterize the sources and rates of methane emissions from the oil and gas sector. B.C. has shown leadership through the Methane Emissions Research Collaborative (MERC) and with the multi-year partnership with the United Nations Environment Programme (UNEP) International Methane Emissions Observatory.

We are a coalition of leading climate and energy organizations that have been advocating for policy to address methane pollution in Canada since 2016. Our coalition consists of the Pembina Institute, David Suzuki Foundation, Environmental Defense Fund, and Clean Air Task Force.

Context

The B.C. government's CleanBC Roadmap to 2030 proposes a 75% reduction in methane emissions from the oil and gas sector below 2014 levels by 2030 and near-zero methane emissions by 2035.[1] These targets are ambitious and align with Canada's new proposed framework for stronger oil and gas methane emissions regulations as part of broader international climate objectives and commitments such as the Global Methane Pledge.[2,3]

The oil and gas sector in B.C. is the second-largest source of greenhouse gas (GHG) emissions in the province, accounting for about 20% of total GHGs in 2020, and must therefore do its fair share to reduce emissions.[4] To meet B.C.'s 2030 oil and gas sector target, achieving deep reductions from low-cost methane mitigation is needed. It is critical that forthcoming methane regulations for the oil and gas sector in B.C. rapidly accelerate current efforts to reduce

[1] CleanBC, Roadmap to 2030, https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf
[2] Government Of Canada, "Proposed Regulatory Framework for Reducing Oil and Gas Methane Emissions to Achieve 2030 Target", https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reducing-methane-emissions/proposed-regulatory-framework-2030-target.html
[3] Government Of Canada, Canada confirms its support for the Global Methane Pledge and announces ambitious domestic actions to slash methane emissions (Oct. 11, 2021), https://www.canada.ca/en/environment-climate-change/news/2021/10/canada-confirms-its-support-for-the-global-methane-pledge-and-announces-ambitious-domestic-actions-to-slash-methane-emissions.html
[4] British Columbia, Provincial Greenhouse Gas Emissions Inventory, https://www2.gov.bc.ca/gov/content/environment/climate-change/data/provincial-inventory#:~:text=Provincial%20greenhouse%20gas%20emissions%20inventory%20B.C.%27s%20Provincial%20Inventory,use%20and%20forest%20management%20for%20information%20purposes%20only

emissions and mitigate near-term climate warming.[5] Methane abatement will play an important role in meeting B.C.'s 2030 greenhouse gas emissions target for the oil and gas sector.

It is highly likely that, under the current regulatory framework, B.C.'s 2025 methane reduction target will not be met. Numerous studies have consistently shown that methane emissions are as much as twice as high as current estimates.[6, 7, 8, 9] A recent study in British Columbia, conducted by the B.C. MERC, shows that most of the emissions not accounted for in inventories come from storage tanks, compressors, and unlit flares, which account for more than half of all methane emissions in the sector.[10] These additional sources of emissions are either under-estimated or missing from current provincial and federal inventories in Canada and are not effectively managed by current regulations. B.C. also reported compliance issues for the 2020 year, with 65% of facilities not completing the required number of LDAR surveys and 40% of facilities not repairing leaks on time.[11]

With substantial additional emissions coming from sources that are not effectively addressed by current rules, B.C.'s regulations will fall short of meeting the 2025 target. Changes to the regulatory framework must be introduced early as part of forthcoming regulations to address current shortcomings.

Addressing methane is low cost and much can be done using existing technologies already required in other jurisdictions. The International Energy Agency (IEA) found that almost 45%

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[5] Ilissa B. Ocko et al., "Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming" *Environmental Research Letters* 16, no. 5 (2021). https://iopscience.iop.org/article/10.1088/1748-9326/abf9c8

[6] K. MacKay et al., "Methane emissions from upstream oil and gas production in Canada are underestimated," *Scientific Reports* 11, 8041 (2021). https://doi.org/10.1038/s41598-021-87610-3

[7] M.R. Johnson, D.R. Tyner, S. Conley, S. Schwietzke, and D. Zavala-Araiza, "Comparisons of Airborne Measurements and Inventory Estimates of Methane Emissions in the Alberta Upstream Oil and Gas Sector," *Environmental Science and* Technology 5, no. 21 (2021). https://doi.org/10.1021/acs.est.7b03525

[8] D. Zavala-Araiza et al., "Methane emissions from oil and gas production sites in Alberta, Canada," *Elementa: Science of the Anthropocene* (2018) 6:27. https://doi.org/10.1525/elementa.284

[9] E. Chan, D.E. Worthy et al. "Eight-Year Estimates of Methane Emissions from Oil and Gas Operations in Western Canada Are Nearly Twice Those Reported in Inventories," *Environmental Science and Technology* 54, no. 23 (2020). https://doi.org/10.1021/acs.est.0c04117

[10] David R. Tyner and Matthew R. Johnson, "Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data, *Environ. Sci. & Technol.,* 55 (14), 9773-9783 (2021).

[11] BC Oil and Gas Commission, "2020 Equivalency Report," https://www.bc-er.ca/files/documents/Equivalency-Report_FINAL.pdf

of oil and gas methane emissions could be avoided at no net cost.[12] A 2019 study from the Canadian Energy Research Institute (CERI) also shows that ambitious reductions in methane emissions can be achieved for under $24/t CO_2e.

Rapidly tackling methane will be crucial to achieving milestone emission reductions during this decade, thereby making important early progress towards the sector's 2030 target and staving off serious near-term impacts of warming. Strong action on methane will also keep Canada (and Canadian technology providers) at the forefront of global methane mitigation efforts and the development of innovative technology that supports that mitigation.

The urgency — and opportunity — of ambitious action on methane

Methane is a potent greenhouse gas (GHG) with more than 80 times the climate warming impact of the equivalent amount of carbon dioxide. It is thus imperative to rapidly and aggressively reduce global methane emissions to slow the pace and amount of global warming. As noted above, tackling methane represents one of few early opportunities for deep and early emissions reductions in the oil and gas sector. Reducing methane emissions from oil and gas production is one of the most cost-effective and feasible measures to achieve rapid greenhouse gas reductions in the near term.[13] Because methane is the principal component of natural gas, mitigating emissions typically means implementing measures that essentially keep natural gas in the sales line rather than letting it escape into the atmosphere.

Addressing methane emissions in the oil and gas sector is more essential than ever. The latest IPCC Assessment Report (AR6) emphasizes that, in order to keep global warming to 1.5 degrees, global greenhouse gas emissions should peak by 2025, and total economy wide methane emissions should be reduced by a third below 2019 levels by 2030.[14] Yet the global methane trend is currently in the wrong direction: measurements of atmospheric methane concentrations show that both 2020 and 2021 set records for annual increases in methane concentration.[15]

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[12] IEA, Methane Emissions from Oil and Gas (2021), https://www.iea.org/reports/methane-emissions-from-oil-and-gas ("Fossil fuel operations generated nearly one-third of all methane emissions from human activity. Action on methane is therefore one of the most effective steps the energy sector can take to mitigate climate change.").

[13] IEA, Global Methane Tracker 2023, https://www.iea.org/reports/global-methane-tracker-2023/overview

[14] IPCC, "The evidence is clear: the time for action is now. We can halve emissions by 2030." News release, April 14, 2022. https://www.ipcc.ch/2022/04/04/ipcc-ar6-wgiii-pressrelease/

[15] National Oceanic and Atmospheric Administration, "Increase in atmospheric methane set another record during 2021," news release, April 7, 2022. https://www.noaa.gov/news-release/increase-in-atmospheric-methane-set-another-record-during-2021

Cost-effective solutions are available, as demonstrated by proposed and current regulations in the U.S. and Canada

In these comments, we provide examples of cost effective, available technologies and practices that can help B.C. lower methane emissions from the oil and gas sector to meet near and longer-term GHG targets including:

- Environment and Climate Change Canada (ECCC)'s recently proposed globally leading framework for revising federal methane standards.
- The United States Environmental Protection Agency's (EPA) proposed supplemental draft regulations.[16]
- U.S. state regulations that are already in force and in some cases go well beyond the EPA's proposed standards.

Furthermore, the Oil and Gas Climate Initiative (OGCI), a group of twelve major global oil and gas companies, has pledged to **achieve near-zero methane emissions** by 2030.[17] Given the urgency of reducing methane emissions and the importance of showing progress within the oil and gas sector towards its 2030 target, B.C. must move rapidly to strengthen its regulations to align with the established regulatory approaches and international best practices. This will assert B.C. as a global leader on reducing oil and gas sector methane emissions and ensure that its 2030 targets can be met.

In this submission, **we urge B.C. to:**

- Strengthen methane regulations for the oil and gas sector with new rules, at least as protective as the new proposed federal framework.[18] These new rules should apply early in 2025 to facilitate crucial near-term interim emissions reductions. Detailed recommendations are outlined in the sections below.
- Adopt further measures that will achieve near-zero methane emissions in the oil and gas sector by 2030, five years ahead of B.C.'s proposed timeline. In doing so, the B.C. government would match the level of ambition and timeline for methane emissions

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[16] EPA, EPA Issues Supplemental Proposal to Reduce Methane and Other Harmful Pollution from Oil and Natural Gas Operations (Nov. 11, 2022), https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-supplemental-proposal-reduce

[17] Oil and Gas Climate Initiative, "OGCI members aim for zero methane emissions from oil and gas operations by 2030," March 8, 2022. https://www.ogci.com/ogci-members-aim-to-eliminate-methane-emissions-from-oil-and-gas-operations-around-2030/

[18] Govt. Of Canada, Proposed Regulatory Framework for Reducing Oil and Gas Methane Emissions to Achieve 2030 Target, (Nov. 2022), https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reducing-methane-emissions/proposed-regulatory-framework-2030-target.html

reduction already set out by the OGCI, a global consortium of companies representing 30% of global oil and gas production.[19]

Recommendations

1. Set stronger regulations starting in 2025

We recommend that the BCER implement stronger regulations that come into force in 2025 to ensure that the oil and gas sector rapidly utilizes available, established technology and practices to reduce harmful methane pollution. In doing so, the government will help to ensure meaningful emissions reductions take place in this decade, thereby facilitating early progress towards B.C.'s 2030 oil and gas sector target.

Fast implementation of these measures is appropriate because they are proven and can be met with currently available, highly cost-effective technologies-all of which are currently employed in U.S. and Canadian jurisdictions (as detailed below).

1.1. Stronger venting and flaring rules

The practice of venting is responsible for a significant amount of B.C.'s methane emissions, and studies consistently show that vented emissions are underreported.[20]

B.C.'s current rules prohibit venting and flaring at wells and facilities, subject to several exemptions. Venting is allowed under the condition that it is safe and odorless, the duration and quantity of venting is minimized and flaring is not technically feasible.[21] Flaring is allowed during emergencies, for drilling operations, during a workover or maintenance activity at a well provided the flared gas does not exceed 50,000 cubic meters annually, during maintenance activities for facility permit holders, and if allowed by permit.[22]

[19] Oil and Gas Climate Initiative, https://www.ogci.com/action-and-engagement/reducing-methane-emissions/#methane-target

[20] Tyner, "Where the methane is."

[21] Drilling and Production Regulation 282/2010, Pt. 7, Div. 41(1).

[22] Id., Pt. 7, Div. 42.

BCER'S flaring performance requirements allow for the use of flare stacks equipped with auto-igniters or flame-out detection devices. Pit flares are allowed if authorized in the well or facility permit. Flares and incinerators installed after the date the regulation came into force must be designed and operated within the limits specified by a professional engineer however, the rule does not include a specific limit.[23]

A recent study in B.C. found that 23% of methane emissions in the province resulted from unlit flares.[24] This is consistent with numerous studies conducted in the U.S.[25] Based on more than 1,000 flare observations, approximately 5% of large flares are unlit and venting gas at any given time, and another 5% have visible slip of methane or other hydrocarbons–meaning the flare is only partially combusting the methane and the rest is escaping in to the atmosphere.[26]

Finally, we note that Canada is a signatory to the World Bank's *Zero Routine Flaring by 2030* initiative and the BCER should align venting and flaring regulations to achieve this commitment.

1.1.1. Best practices

Several North American jurisdictions have already implemented rules that prohibit routine venting and flaring and require all flaring and combustion to be done with highly efficient devices, equipped with auto-igniters and subject to routine inspections for malfunctions:

- **Canada (Federal – Proposed):** Oil facilities with combined vent and flare volumes of >5 m^3/day must eliminate venting by conserving natural gas at efficiencies of at least 98%. Flaring at oil sites is not allowed and enclosed combustors must have auto igniters or continuous pilot monitoring. Duty holders must also control surface casing vents using conservation or destruction equipment operating at efficiencies of at least 98% and 99%, respectively.[27]

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[23] Id., Pt. 7, Div. 44.

[24] Tyner, "Where the methane is."

[25] EDF Permian Methane Analysis Project, Final Report, https://blogs.edf.org/energyexchange/files/2022/11/PermianMAPFinalReport.pdf

[26] Permian MAP, Flaring Aerial Survey Results (2021), https://www.permianmap.org/flaring-emissions/ (last visited Feb. 13, 2023)

[27] Government Of Canada, "Proposed Regulatory Framework for Reducing Oil and Gas Methane Emissions to Achieve 2030 Target."

- **Alberta (Peace River region):** Routine venting of solution gas is not allowed, non-routine flaring is limited to 3% of total annual gas production volumes, and conservation rates at heavy oil and bitumen wells and facilities must exceed 95%.[28]
- **U.S. EPA:** Recently proposed regulations prohibit routine venting and flaring of associated gas.[29] Under EPA's proposed framework, operators must route associated natural gas to a sales line, use it on site for fuel or another useful purpose that a purchased fuel or raw material would serve, recover the associated gas from the separator and reinject it into the well for enhanced oil recovery, or inject it into another well. Flaring is only permitted if operators demonstrate that capture of the gas is unsafe or technically infeasible. For any flaring, operators must use control devices with efficiencies of at least 95%.[30] All pollution control equipment is subject to regular inspection, performance, and compliance requirements.[31] For all flares, the EPA proposed requirements to ensure a pilot flame is always lit through continuous monitoring with a device such as a thermocouple, ultraviolet beam sensor, or infrared sensor and monitoring of net heating value. The EPA also proposed performance requirements for other combustion control devices.[32] Specifically, flares and enclosed combustion devices must have a continuous pilot flame and install a system capable of continuously monitoring for the presence of a pilot or combustion flame. This is to ensure the flare or ECD achieves the required destruction efficiency at all times.[33] Operators would also be required to monitor for visible emissions every month.[34]
- **Colorado:** Prohibits routine venting or flaring of associated gas from all wells.[35] Temporary venting and flaring is allowed during specifically enumerated exemptions such as where necessary for safety or during maintenance activities.[36] 98% control is required when a combustor is used instead of vapor capture (open flares are not generally allowed).[37] Auto igniters are also required for any combustion control device.[38]

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[28] Alberta Energy Regulator, *Directive 084: Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace* River *Area* (2018). https://static.aer.ca/prd/documents/directives/Directive084.pdf

[29] 87 Fed. Reg. 74,702 (Dec. 6, 2022).

[30] Proposed 40 C.F.R. § 60.5377b.

[31] 87 Fed. Reg. 74702, 74705 (Dec. 6, 2022).

[32] Proposed 40 C.F.R. § 60.5417b.

[33] 87 Fed. Reg. 74,795.

[34] Id.

[35] 2 Colo. Code Regs. § 404-1-903.d.

[36] Id. at § 903.d.(5).

[37] 5 Colo. Code Regs. § 1001-9-D.I.c.1.d; II.C.1.b.

[38] *Id*. at §§ D.I.1.e; II.B.2.d.

- **New Mexico:** Prohibits routine venting and flaring of gas from wells.[39] Temporary venting and flaring is permitted during specifically enumerated exemptions.[40] For tank controls, 98% control is required when a combustor is used instead of vapor capture.[41] Auto igniters or continuous pilot flames are required for any combustion control device.[42] Auto igniters, continuous pilot flames or manual ignition are required for flares.[43] All control devices must be inspected monthly for defects, leaks, releases and to ensure proper operation.[44] Operators must install thermocouples or other approved devices capable of continuously monitoring flares or combustion devices to ensure proper operation.[45]

1.1.2. Recommendations

As a first step towards eliminating routine venting and flaring by 2030 and improving flaring and combustion performance, we recommend that the BCER implement these best practices in 2025:

- Eliminate routine venting and flaring[46] of associated/solution/casinghead gas at all wells. This will align with existing best practices in other jurisdictions as outlined above and will conform with Canada's international commitments to the World Bank's *Zero Routine Flaring by 2030* initiative.
- Prohibit venting other than in emergencies or where specifically authorized, pursuant to other source-specific rules (e.g., tanks with emissions below the required limits contained in Division 52.03, as revised pursuant to our suggestions below).
- Prohibit open flares for control of tank emissions. Specify a 98% destruction and removal efficiency (DRE) for all enclosed combustors and require auto igniters or continuous monitoring of pilots, as well as frequent operator inspections, at all combustors, as Colorado and New Mexico do.

39 N.M. Code R. § 19.15.27.8.

40 Id.

41 N.M. Code R. § 20.2.50.123.A, B.(1).

42 Id. at § 115.D.(1)(c).

43 Id. at § 115.D.(1)(b).

44 Id. at § 115.C.(2).

45 Id. at §§ 115.C(2)(a); D(2)(a).

46 Routine venting and flaring is done at a well in the absence of a gathering line or sufficient takeaway capacity.

1.2. Lower tank emission limits

Studies show that tanks are significant sources of emissions in B.C.[47, 48] Tank emissions can be reduced by placing stringent limits on venting, requiring operators capture tank emissions, and requiring frequent inspections of control devices and thief hatches to ensure they are properly functioning.

We compared BCER's current tank limits to control thresholds (i.e., limits) in leading U.S. states. B.C.'s limits are considerably higher than the most protective limits in the U.S. which are in place in Colorado and New Mexico. They are also considerably higher than U.S. EPA requirements for new and existing sources. B.C.'s tank emission limits are 1,250 cubic meters per month for facilities that began operations on or after Jan. 1, 2022, and 9,000 cubic meters per month for facilities that began operations prior to this date. We converted these limits to methane using a methane density of 0.668 kg/m3. Pursuant to this analysis, B.C.'s emissions limit for new tanks is roughly equivalent to 11 tons of methane per year and the existing tank limit is roughly equivalent to 80 tons of CH_4 per year. The limit for existing tanks is four times higher than the EPA proposed limit for existing tanks of 20 tons per year (TPY) of CH_4. It is also significantly higher than the most protective tank limit in the U.S., which is Colorado's tank limit of 2 TPY of VOCs. This equates to roughly 0.3 TPY of methane.

A 2023 study in B.C. found that the majority of emissions from controlled storage tanks are from access points such as thief hatches and pressure relief valves.[49] Thief hatches can open and unintentionally emit either through improper latching after routine operations (checking tank levels, etc.) or, as a result of a pressure build-up within the tank.[50] Various developers of automation technology and equipment have made viable options for thief hatch monitoring available to industry operators.[51] When taking into account the lost revenue associated with

[47] Tyner, "Where the methane is."

[48] Matthew R. Johnson et al., "Origins of Oil and Gas Sector Methane Emissions: On-Site Investigations of Aerial Measured Sources," ACS Publications (2023), https://pubs.acs.org/doi/10.1021/acs.est.2c07318

[49] Johnson, "Origins of Oil and Gas Sector Methane Emissions"

[50] Vance Ray, Use wireless to monitor thief hatches, Control (July 18, 2019), https://www.controlglobal.com/manage/asset-management/article/11301041/use-wireless-to-monitor-thief-hatches; Teledyne FLIR, How Safe are Thief Hatches? (June 18, 2021), https://www.flir.com/discover/instruments/gas- detection/how-safe-are-thief-hatches/

[51] See, e.g., OleumTech, Thief Hatch Monitoring: Simple and Cost-effective Solution for Minimizing Emissions Risk, https://oleumtech.com/news-and-blogs/2021/02/thief-hatch-monitoring-solution-for-minimizing-emissions-risk (last visited Feb. 10, 2023); Scott Keller, SignalFire Introduces Tilt Scout – the "Hatch Watchdog" Wireless Thief Hatch Sensor for Remote Thief Hatch Monitoring, SignalFire, https://www.signal-fire.com/signalfire-introduces-hatch-watchdog-wireless-thief-hatch-sensor-remote-tank-monitoring/ (last visited Feb. 10, 2023).

wasted gas lost through open thief hatches, installing monitoring systems may ultimately benefit operators financially while also preventing harmful emissions.[52]

The suggestions above for flares and combustors apply equally to our tank recommendations below.

1.2.1. Best practices

- **U.S. EPA:** Since 2011, EPA has required that all new tanks with the potential to emit volatile organic compounds (VOC) emissions in excess of 6 short TPY[53] reduce these emissions by 95%. The EPA's draft regulations also propose that existing storage tanks or tank batteries with a potential to emit of 20 TPY of methane must also reduce emissions by 95%.[54] Operators must equip storage vessel thief hatches with alarms, automated systems to monitor for pressure changes, or automatically closing thief hatches.[55]
- **Colorado:** All new and existing tanks with actual uncontrolled emissions of 2 TPY of VOC (typically, about 0.3 tons of methane, according to U.S. EPA data) or greater are subject to a 95% emissions control limit, with extensive inspection, performance, and compliance requirements.[56] 98% control is required when a combustor is used instead of vapor capture. Open flares are not generally allowed.[57]
- **New Mexico**: All new or modified tanks with the potential to emit 2 TPY of VOC upon start-up must reduce emissions by 95%.[58] Existing tanks with a potential to emit 3 TPY of VOC located at multi-tank batteries, as well as existing tanks with a potential to emit 4 TPY of VOCs at single tank batteries, must also reduce emissions by 95%.[59] For all

[52] *See, e.g.*, Jeff Voorhis, *Best Practices for Vapor Recovery Systems to Reduce Venting and Flaring* at 4, https://www.epa.gov/sites/default/files/2016-04/documents/8voorhis.pdf (positing that when subtracting the estimated cost of wasted gas from estimated project costs, industry operators would ultimately experience a net gain.); Ray, *supra* note 538 (One company's costs for installing monitoring technology on an 8-tank battery totals $8,300).

[53] 1 U.S. short ton = 0.907 metric ton. Since U.S. emission standards are expressed in short tons, we retain that unit here, so the terms "tons" and "tons per year" or "TPY" refer to U.S. short tons.

[54] 87 Fed. Reg. 74702, 74800 (Dec. 6, 2022).

[55] 87 Fed. Reg. 74702, 74803 (Dec. 6, 2022).

[56] 5 Colo. Code Regs. § 1001-9-D.II.C.

[57] *Id*. at D.II.C.1.b.

[58] N.M. Code R. § 20.2.50.123.A, B.(1).

[59] Id. at § B.(1).

tanks, if combustion control devices are used, tanks must have a minimum design combustion efficiency of 98%.[60]

- **California**: Operators must conserve gas from tanks rather than flaring or combusting. Destruction is only allowed where conservation is infeasible.[61]

1.2.2. Recommendations

We urge the BCER to implement the following rules, starting in 2025:

- Lower the tank limits to match the most protective limits in the U.S. - those required by Colorado. These limits equate to 0.3 TPY of methane for new and existing tanks.[62] This equates to 34 cubic meters per month.[63]
- Require operators equip thief hatches on tanks with alarms or similar equipment to quickly notify operators when they pop open due to process upsets that may drastically change tank pressures relative to the atmosphere, as EPA has proposed.
- Design standards to require or incentivize operators to capture rather than combust methane from tanks, unless doing so is infeasible.[64] We recommend that operators be required to capture vented emissions and either use the captured natural gas on-site as fuel or send it to a sales line. Where feasible, this should be adopted as a primary compliance mechanism. Only where operators demonstrate that capture and on-site use or sales are infeasible should destruction (with combustion devices) be allowed. The benefits of capturing gas are multifold: reduced emissions of methane and other air pollutants and reduced wasted gas resulting in additional natural gas sales (increasing revenue for operators and royalties for governments). Tank vapour capture equipment should be properly sized to prevent fugitive emissions.

[60] Id.

[61] 17 Cal. Code Regs § 95668.

[62] We converted Colorado's VOC limit to methane using a VOC:CH4 ratio based on EPA's oil and gas tool.

[63] For this analysis we divided 0.3 tpy by 12 to convert tpy into tons per month, converted tons per month into kilograms per month, and then used a methane density of .668 kg/m3 to convert the kilograms of methane per month into m3 methane per month.

[64] For example, the California Air Resources Board requires separators and tank systems with an annual emission rate of >10 metric tons/year of methane to control emissions from the separator and tank system and uncontrolled gauge tanks located upstream of the separator and tank system with the use of a vapor collection system (CARB: 17 Cal. Code Regs § 95668.(a)(6),(7)).

1.3. Stronger leak detection and repair (LDAR) rules

1.3.1. Scientific studies

Fugitive emissions are generally not intended as part of normal operations and can be broadly classified as leaks and unintentional vents. Sources of fugitive emissions include valves, flanges, connectors, thief hatches, pump diaphragms, seals, open-ended lines, and many others. Causes of these emissions include persistent issues, such as equipment malfunctions (e.g., stuck open separator dump valve), as well as intermittent, short duration events (e.g., uncontrolled flashing from condensate tanks).[65] Fugitive emissions can also result from devices that vent as part of normal operations, such as natural-gas driven pneumatic controllers, and control devices or equipment combusting natural gas, like flares, when those devices are not operating as intended. Fugitive emissions that result from abnormal operating conditions or equipment failures are often referred to as abnormal process emissions and may also result in very large emission events, often termed "super-emitters."

Super-emitters and abnormal process emissions are often not well-represented (and may not be represented at all) in official inventories because they can be intermittent and are easily missed when taking equipment- or component-level measurements.[66] Bottom-up methods that estimate emissions using component or equipment counts and emission factors fail to account for super-emitter events and result in artificially low overall emission estimates. These measurement techniques capture only a snapshot of time; therefore, they may not be representative of emissions over longer timescales and are likely to miss intermittent emissions. Aerial detection methods and other top-down measurement and quantification techniques have documented the significance of large emission events and their large contribution to total emissions. This well-documented "fat-tailed" emission distribution means that 5-10% of sites are often responsible for 50% or more of total emissions.

Over the last decade, research by Environmental Defense Fund (EDF) and others has quantified the significance of methane emissions caused by oil and gas production and the persistent underestimation of fugitive and abnormal process emissions.[67] A large body of measurement-based studies have consistently found higher oil and gas methane emissions than is estimated

[65] Zavala-Araiza et al., *Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133
[66] *See* IEA, *Methane Tracker Database* (October 2021), https://www.iea.org/articles/methane-tracker-database (summary of inventory estimates).
[67] EDF, Methane research series: 16 studies, https://www.edf.org/climate/methane-research-series-16-studies

in EPA inventories.[68] Bottom-up approaches greatly underestimate emissions because they are based on assumptions that do not account for large events caused by malfunctions and other abnormal conditions.[69] Accounting for these emission events can increase inventory estimates by 60-70%, underscoring the importance of quickly detecting and fixing major leaks.[70]

Recent research has found several common characteristics of oil and gas industry methane emissions. First, emissions occur across the value chain from well to end use, but are concentrated in the production and gathering segments, including well pads, tank batteries, and gathering compressor stations.

Second, all oil and gas facility types have a skewed distribution in which 5-10% of the highest emitting sites are responsible for about half of total emissions; however, the identity of these high-emitting sites can change with time and is difficult to predict. One study conducted in and around Red Deer, Alberta found that 20% of the oil and gas facilities measured were responsible for 74–79% of total methane emissions.[71] Due to the skewed distribution of emission rates and the intermittency of some large emission events, the speed of detecting and stopping large emission sources is most critical for reducing total emissions—underscoring the importance of frequent monitoring and quick repair timelines.

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[68] Lyon et al., Constructing a spatially resolved methane emission inventory for the Barnett Shale region, 49 Env. Sci. Tech. 49, 8147–8157 (2015); Zavala-Araiza et al., Reconciling divergent estimates of oil and gas methane emissions, 112 Proc. Natl. Acad. Sci. 15597–15602 (2015); Zavala-Araiza et al.,. Super-emitters in natural gas infrastructure are caused by abnormal process conditions, 8 Nat. Comms. 14012—1421 (2017); Zimmerle et al., Methane emissions from the natural gas transmission and storage system in the United States, 49 Env. Sci. Tech. 9374–9383 (2015); Omara et al., Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale region, 50 Env. Sci. Tech. 2099—2107 (2016); Peischl, J. et al., Quantifying atmospheric methane emissions from Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions. 120 J. Geo. Res. Atmospheres, 2119–2139 (2015); Caulton et al., Importance of super emitter natural gas well pads in the Marcellus Shale. 53 Env. Sci. Tech. 4747—4754 (2019); Robertson, New Mexico Permian Basin measured well pad methane emissions are a factor of 5—9 times higher than U.S. EPA estimates, 54 Env. Sci. Tech. 13926—13934 (2020); Zhang et al., Quantifying methane emissions from the largest oil-producing basin in the United States from space, 6 Sci. Adv. 5120 (2020); Lyon et al., Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic, 21 Atmos. Chem. Phys. 6605-6626 (2021).

[69] Rutherford et al., *Closing the methane gap in US oil and natural gas production emissions inventories*, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4#citeas

[70] Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 Science 186 (2018), https://science.sciencemag.org/content/361/6398/186

[71] Zavala-Araiza, et al., Methane emissions from oil and gas production sites in Alberta, Canada. *Elementa: Science of the Anthropocene, 6:27* (Mar. 2018), https://online.ucpress.edu/elementa/article/doi/10.1525/elementa.284/112796/Methane-emissions-from-oil-and-gas-production

Third, low production or marginal wells tend to have lower absolute emissions than high production wells, but much higher loss rates as a percentage of gas production. A recent survey of wells in southern Alberta noted that emissions volumes were not proportional to levels of production, indicating that both high- and low-producing wells need to be surveyed frequently.[72]

Fourth, because emissions are often episodic, after a screening approach finds a high emitting site, follow-up surveys must not only look for ongoing leaks, but include a root-cause analysis evaluating equipment and operational issues that could trigger high emission events. For example, an undersized tank control system could cause the tank hatch to intermittently pop open; closing the hatch will temporarily reduce emissions, but the problem will likely recur until the control system is fixed.

Finally, emissions can almost always be mitigated once detected, sometimes with a simple repair to stop a leak, and other times by implementing operational or equipment changes that improve a site's efficiency.

1.3.2. Compliance

B.C. reported compliance issues for the 2020 year, with 65% of facilities not completing the required number of LDAR surveys and 40% of facilities not repairing leaks on time.[73] This is concerning for a number of reasons. By way of contrast, reports from Colorado demonstrate that the vast majority of repairs are made immediately.[74]

1.3.3. Best practices

Regular inspections with modern detection instruments (such as optical gas imaging (OGI) cameras and emerging alternative technologies) are the best way to minimize emissions from these sources. Recognizing this, many jurisdictions now require frequent, comprehensive instrument-based inspections at most or all production, processing and compression sites:

- **Canada (Federal**): The new proposed regulatory framework would require monthly inspections of all facilities, including single wellheads.
- **Alberta (Peace River region):** Operators are required to conduct monthly instrument-based LDAR surveys at high-risk sources which include storage tanks, flare

[72] Arvind P Ravikumar et al. Repeated leak detection and repair surveys reduce methane emissions over scale of years, *Environ. Res. Lett.* **15** 034029 (2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1.

[73] BC Oil and Gas Commission, "2020 Equivalency Report," https://www.bc-er.ca/files/documents/Equivalency-Report_FINAL.pdf

[74] See LDAR Annual Reports, https://cdphe.colorado.gov/2020-ldar-annual-reports-regulation-7-section-xvii

ignitors/pilots and compressor seals, and must quantify all leaks that are not repaired within 24 hours.[75]

- **Colorado:** Requires existing tanks, compressor stations and well sites to be surveyed at various frequencies ranging from annual to monthly but, all new well sites are inspected monthly.[76]
- **California**: Requires quarterly instrument-based inspections of all well sites, gathering and boosting compressor stations, and transmission compressor stations.[77]
- **New Mexico:** Requires regular instrument-based inspections for all well sites, including quarterly inspections for all well sites with calculated potential annual emissions of 5 TPY of VOCs or more.[78] Compressor stations with potential VOC emissions of 25 TPY or more must also conduct quarterly inspections.[79]
- **U.S. EPA**: Proposed an equipment-based approach where the frequency and type of surveys for well sites and compressor stations depends on the type and number of leak or failure-prone equipment at the facility.[80] EPA proposes to require quarterly OGI surveys for compressor stations and for well pads with at least one piece of leak or failure prone production and processing equipment, such as tanks, control devices, and natural gas- powered pneumatic controllers, or at well pads with any combination of two or more pieces of production and processing equipment.[81] Wellhead only sites with two or more wellheads are subject to semi-annual OGI surveys. Single wellhead only sites and single wellhead sites with one piece of non-failure prone equipment must perform quarterly AVO surveys to detect leaks. Any site with mandated OGI surveys also requires operator AVO at specific frequencies throughout the year determined by the site type.

1.3.4. Alternative LDAR

We urge BCER to allow alternative LDAR technologies to traditional, ground-based OGI. These technologies, when properly implemented, can offer a promising pathway to more frequent and cost-effective screening for large emission events. The combination of annual OGI inspections

[75] Alberta Energy Regulator, Directive 084: Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area, https://www.aer.ca/regulating-development/rules-and-directives/directives/directive-084
[76] 5 Colo. Code Regs. § 1001-9-D.II.E.4.
[77] 17 Cal. Code Regs. § 95669.
[78] NM Admin. Code § 20.5.20.116.
[79] *Id.*
[80] 87 Fed. Reg. 74702 (Dec. 6, 2022).
[81] See 87 Fed. Reg. 74702, 74735 (Dec. 6, 2022).

and periodic screening using advanced methane detection technologies can achieve equivalent emissions reductions as frequent OGI inspections.

The EPA recently proposed to allow operators to use advanced methane detection technologies at various frequencies (and with various OGI or AVO pairings) depending on the detection capability of the advanced methane detection technology.[82] Per the EPA proposal, operators could use advanced methane detection technology in lieu of the required OGI inspection, provided the alternative achieves equivalent emissions reductions. Because most advanced methane detection technologies have detection thresholds greater than OGI, such inspections must be coupled with an annual OGI inspection to ensure that smaller leaks are also detected and repaired.

Alternative methane detection technologies for LDAR include vehicle-based systems, drones, aircraft, and satellites coupled with on the ground OGI inspections. Deployment frequencies required to achieve equivalent emissions reductions to OGI are set with a technology-agnostic matrix that considers the 90% probability of detection (POD) limit of these technologies and the site type. An operator choosing the screening approach must still be required to conduct follow-up OGI inspections to identify the specific source of any detected emissions, and to repair any leaks within 30 days of detection. Per the EPA proposal, operators must conduct a root cause analysis and corrective action if the emissions are due to a failure of a control device, cover or closed vent system.

The EPA is also considering allowing continuous monitors for LDAR with two different action levels: one for large leaks or malfunctions and the other for small leaks that persist over time. A root cause analysis and corrective action are required whenever either action level is exceeded. Continuous monitors offer promising alternatives to periodic inspections, provided certain criteria are met. First, the action levels must be set appropriately to ensure equivalent emission reductions as periodic OGI inspections. Second, sensor placement must be adequate to detect emissions from all fugitive emissions components and control devices (e.g., sensors must be high enough to detect emissions from raised control devices such as flares). Third, continuous monitors must be coupled with an annual OGI inspection to ensure that small, persistent leaks that fall under action levels are identified and mitigated.

1.3.5. Centralized measurement based LDAR

The B.C. government should also consider developing an independent, centralized, and provincial measurement-based LDAR program. This program could be housed in an arm's-

[82] 87 Fed. Reg. 74702 (Dec. 6, 2022).

length organization such as an academic institution or the NRCan Centre of Excellence to ensure independence. Data from this program could fulfill the need for government and regulators to conduct regular inspections to ensure industry is compliant. Industry could also have an option to pay into the program and use it to conduct LDAR. This approach is efficient as it combines regulatory LDAR and compliance measures. It also addresses inequality concerns by making measurement-based LDAR more accessible to small companies that have fewer resources to manage and run LDAR programs and explore alternative technologies. A centralized program would also decrease costs of LDAR across the sector through economies of scale and could provide centralized LDAR data to many stakeholders including industry, regulators, governments, researchers, and the public.

1.3.6. Recommendations

We recommend that B.C. implement the following measures, starting in 2025:

- Monthly instrument-based LDAR inspections at all sites;
- Comprehensive instrument-based inspections should apply to all leak and failure-prone equipment, including control devices such as flares;
- More stringent enforcement to improve industry compliance rates on LDAR requirements;
- Include an alternative LDAR pathway;
- Consider developing an independent, centralized, and provincial measurement-based LDAR program.

1.4. Zero emitting pneumatic equipment

Pneumatic controllers and pneumatic pumps are a significant source of methane pollution. Recent field studies in Alberta indicate that pneumatic controllers and pumps are responsible for about 20% of methane emissions.[83] British Columbia requires all new pneumatic controllers and pumps to be zero bleed. In addition, large compressor stations were required to retrofit existing controllers to eliminate emissions by the beginning of 2022. We support the steps B.C. has taken to date to eliminate emissions from gas-powered pneumatic controllers. Yet, as demonstrated below, we urge the BCER to take additional, bolder action.

There are a number of approaches that could eliminate, or essentially eliminate, methane and other emissions venting from pneumatic controllers. A 2016 study shows that cost-effective zero-bleed options exist for both new and existing pneumatic devices, even where grid power is

[83] Tyner, "Where the methane is."

not being used at the site. These options have been proven to work robustly in upstream oil and gas operations in Canada and more broadly in North America.[84] A 2023 report finds that there is a well-established group of providers of zero-emissions equipment to replace polluting pneumatic controllers.[85] The report identifies 40 firms supplying this equipment, finding that they are well-established companies which have developed strong supply chains and are well-equipped to meet demand that will result from retrofit mandates, such as those proposed by the U.S. EPA.

Numerous technologies are available for retrofitting sites to eliminate venting controllers. Two Canadian examples are Westgen Technologies' EPOD and Calscan's Bear solar-ready electric actuators and fail-safe power and controller systems.[86] Technologies like this allow replacement of venting gas-driven controllers at all sites, including small off-grid locations with harsh winter conditions, making it feasible to eliminate the use of wasteful, polluting venting controllers.

1.4.1. Best practices

A number of Canadian and U.S. jurisdictions have standards in place requiring zero-bleed pneumatic devices and pumps at new and existing facilities. Similarly, the federal government and U.S. EPA have proposed zero-emission standards for pneumatic devices.

- **ECCC:** Draft regulations propose requiring all pneumatic devices and pumps to be non-emitting or capture emissions.
- **U.S. EPA:** Draft regulations propose requiring non-emitting controllers at all new and existing well sites, production facilities, processing plants, and compressor stations in the U.S. Pumps at new facilities with electricity must also be non-emitting. EPA has proposed that states – responsible for implementing standards for existing sources under the U.S. Clean Air Act – will be expected to require operators to retrofit all controllers within three years of their implementation plan approvals.
- **Colorado:** Prohibits venting gas-driven controllers at new and expanded sites (since May 2021) and requires operators to retrofit a portion of their fleet of venting gas-driven controllers to eliminate emissions. Operators were required to convert a

[84] Carbon Limits, *Zero Emission Technologies for Pneumatic Controllers in the USA: Applicability and cost effectiveness* (2016), 3-4. https://www.catf.us/resource/zero-emission-technologies-for-pneumatic-controllers-usa/

[85] Datu Research, Zero-emission Alternatives to Pneumatic Control: How Ready are Technology Providers to Meet Increased Demand? (Jan. 2023)

[86] Westgen Technologies, "EPOD AP Series." https://westgentech.com/epod-lineup/
Calscan Solutions, "Bear Electric Actuators." http://www.calscan.net/products_bearfamily.html#bear_actuators
Calscan Solutions, "Bear Fail Safe System." http://www.calscan.net/solutions_BearFailSafe.html

significant portion of their facilities or controllers to use of non-emitting controllers by May of last year and must complete additional conversion by May 2023.
- **New Mexico:** Prohibits the use of new venting gas-driven controllers and will also require operators to phase out existing gas-driven controllers over a period of several years.

1.4.2. Costs

Requiring zero bleed pneumatic controllers and pumps is cost effective. We analyzed the cost effectiveness of requiring zero-bleed controllers and pumps in Canada, relying on information contained in the EPA's Technical Support Document for its proposed rules.[87] Pursuant to this analysis, we find:

- New production facilities
  - o Zero-bleed electric-powered controller installations are cost-effective for all facility size classifications with a range of $92 to 354 CAD/metric ton abated methane emissions**.**
  - o Zero-bleed compressed air systems are cost-effective for medium and large facilities, with a range of $883 to $1,766 CAD/metric ton abated methane emissions.
  - o If avoided emissions are brought to market, zero-bleed electric controllers connected to the grid could have annual net savings for all facility sizes. Electric controls that are solar-powered could have net savings for medium and large facilities.
- Existing production facilities
  - o Zero-bleed electric-powered controller installations are cost-effective for all facility size classifications with a range of $236 to 380 CAD/ metric ton abated methane emissions.
  - o Zero-bleed compressed air systems are cost-effective for medium and large facilities, with a range of $897 to $1,716 CAD/metric ton abated methane emissions.
  - o If avoided emissions are brought to market, zero-bleed electric controllers connected to the grid have annual net savings for medium and large facility sizes.

[87] Specifically, we relied on EPA's supplemental TSD documents for capital costs, emissions saved and key assumptions. For resale values, we estimated the additional revenue if all the avoided methane made it to market. Key assumptions include a gas price of $4.65 CAD/MMBtu (this is the average 2022 hub price at the West Coast Station 2 hub, per S&P Global) and a conservative assumption that natural gas is 100% methane (this reduces additional revenue).

- Zero-bleed electric-powered pumps are cost-effective, with a range of $153 to $1,394 CAD/metric ton methane abatement.

1.4.3. Recommendations

We recommend that the B.C. require all new and existing pneumatic devices and pumps to be non-emitting or to capture their emissions starting in 2025.

1.5. Stronger rules for compressors

Emissions associated with compressors and engines driving them are very significant. These include:

- Emissions from the seals for moving parts on compressors themselves, which are generally not designed to be hermetic. These include venting from rod-packing seals for reciprocating compressors and emissions from centrifugal compressor seals.
- Emissions due to incomplete combustion of fuel methane (methane slip) for compressors driven by natural gas-fired engines.
- Venting emissions from compressor blowdowns and starters.
- Emissions from engine crankcase venting.

Recent work in British Columbia found that more than half of emissions from quantified sources identified with aerial surveys were from compressors.[88] It is therefore essential that B.C.'s updated regulations utilize best practices and emerging technology to aggressively reduce emissions from these sources.

1.5.1. Compressor Seals - Reciprocating

The current B.C. rule requires that "large" reciprocating compressors (i.e., four or more throws) route hydrocarbon gas to conservation equipment or flare in accordance with sections 42 and 44. However, for reciprocating compressors with fewer than four throws, the requirements are:

> (a) that the emissions of natural gas from the compressor do not exceed five cubic meters per hour per throw on that compressor; and
>
> (b) (as of January 1, 2022) that the emissions of natural gas from the permit holder's provincial fleet does not exceed 0.83 cubic meters per hour per throw on the compressors in the fleet that are in operation. This standard applies to the operator's

[88] Johnson, "Origins of Oil and Gas Sector Methane Emissions."

entire provincial fleet of reciprocating compressors (including the large compressors), meaning that the very low emission rate from the controlled large compressors will bring down the average emissions for the operator's fleet, reducing or eliminating its effectiveness for compressors with fewer than four throws.

In 2021, the U.S. EPA proposed a threshold of 2 scfm (3.4 cubic meters per hour) for reciprocating compressors. While this is higher than the fleet average standard in place in B.C., the inclusion of larger (controlled) compressors in the average calculation for B.C. operators suggests that it is very likely that the EPA's proposed standard is effectively more stringent than B.C.'s fleet average standard. Moreover, B.C.'s five cubic meters per hour per throw standard is certainly much weaker than the EPA's proposed standard. (We note however that EPA's standard does not apply to compressors on well pads).[89]

Moreover, EPA's 2 scfm threshold is too high, and a threshold of 0.5 scfm (0.82 cubic meters per hour), ***without averaging***, would be justified due to higher emission reductions and cost-effectiveness for the tighter standard, as we showed in our comments to the U.S. EPA in 2022.

CATF estimates that imposing a 0.5 scfm threshold for rod packing replacement would entail a cost of $270/ton of methane, not accounting for gas savings, and $89/ton of methane after accounting for gas savings at gathering and boosting compressors, which is the highest cost segment.

Segment	VOC Cost of Control w/o Savings ($/ton)	VOC Cost of Control with Savings ($/ton)	Methane Cost of Control w/o Savings ($/ton)	Methane Cost of Control with Savings ($/ton)
Gathering and Boosting	$972	$319	$270	$89
Processing	$417	($236)	$116	($66)
Transmission	$4,432		$123	
Storage	$5,462		$151	

Figure 1: Costs of rod packing replacement with a 0.5 scfm threshold (single pollutant costs)[90]

Again, we note that this analysis justifies a threshold for repair <u>for individual units</u> of 0.5 scfm (0.82 cubic meters per hour). If it is cost-effective to repair individual units at that threshold, then a fleet average standard well below 0.83 cubic meters per hour will be cost-effective,

[89] In EPA's 2021 proposal, it was proposed to require rod packing to be replaced when it exceeded this threshold, but in its 2022 proposal, EPA proposed to allow repair to meet the threshold, not replacement. We argued against this, showing that it would result in significantly less emissions reductions. CATF et al comments on EPA's 2021 NSPS OOOOb / EG OOOOc proposal, page 128-9.
[90] CATF et al comments on EPA's 2021 NSPS OOOOb / EG OOOOc proposal, page 170

particularly since controlled large compressors are included in the fleet average calculation under the B.C. rule.

Finally, ECCC regulations are also more stringent than B.C.'s rules, limiting emissions from new compressors to 0.001 cubic meter per minute per throw (0.060 cubic meter per hour per throw) and limiting emissions from existing compressors to 0.023 cubic meter per minute per throw (1.28 cubic meter per hour per throw), as of Jan 1, 2023. Using similar logic to that discussed immediately above, ECCC's standard is functionally more stringent that B.C.'s since it applies to each unit, whereas B.C.'s standard is averaged across the fleet, including units meeting the more stringent standard for large compressors.

1.5.2. Compressor seals - centrifugal

B.C.'s current rules subject centrifugal compressors to a 0.17 cubic meter per minute standard for existing compressors and a 0.057 cubic meter per minute threshold for new compressors (as of Jan 1, 2021).

The U.S. EPA has proposed, for wet seal centrifugal compressors, requiring all new compressors to be routed to control device for 95% control, while existing compressors would need to meet an emissions standard of 3 scfm (0.08 cubic meter per minute). The EPA has proposed that all dry seal centrifugal compressors (new and existing) would need to meet the 3 scfm (0.08 cubic meter per minute) emissions standard.

1.5.3. Compressor engine exhaust (slip)

Many studies over the past decade have demonstrated that methane slip from natural gas-fired centrifugal compressors can be a very sizable source of methane emissions. Recognizing this, ECCC's Proposed Regulatory Framework for 2030 would limit methane emissions from compressor engines to 1 gram of methane per kWh methane, including from smaller compressors. Numerous technologies to reduce emissions in compressor exhaust are in development, while research and information from manufacturers also indicate that tuning, updating air-fuel controls, and various retrofit options may significantly reduce methane slip from reciprocating gas-fired engines.[91]

Electric motors completely eliminate methane slip, with the additional very important advantage of also addressing carbon dioxide emissions. Given the very low carbon intensity of

[91] Johnson, "Origins of Oil and Gas Sector Methane Emissions."

grid electricity in B.C., electrification greatly reduces the overall carbon dioxide emissions associated with compression.

1.5.4. Compressor blowdown and starter emissions

Numerous methods have been identified to reduce or eliminate emissions from compressor startups and blowdowns. In addition to changing management processes to reduce blowdown and startup frequency and volumes, approaches have been identified to conserve / utilize gas when blowdowns occur, or control methane emissions via combustion when that is not possible. Recognizing the availability of these options, ECCC's Proposed Regulatory Framework for 2030 would require operators to control emissions from planned pipeline blowdowns by routing gas to a capture system for conservation or control via combustion (with potential options for alternate approaches that would achieve equivalent emissions available in some cases).

Colorado is currently phasing in implementation of rules that require operators of large midstream compressors (those with volumes over 50 cubic feet) to capture and recover hydrocarbons from all compressor blowdowns, if those blowdowns would emit more than small amounts of pollutants (1.5 – 2.0 short tons of methane per year, depending on the location of the compressor, or similarly small amounts of VOC).[92]

B.C. rules currently cover emissions from pneumatic engine starters, although operators can avoid the provision for any starter for which emissions cannot be controlled or conserved simply by reporting that fact – no justification required (BC Regs §52.07(2)). While the regulations for compressor emissions (§52.04) could be read to apply to blowdown emissions, we do not believe operators would generally interpret them to apply in that way since there is nothing that clearly indicates that blowdowns are included and the structure of the rule (e.g., expressing emissions limits as hourly rates) does not suggest a focus on blowdowns.

1.5.5. Compressor engine crankcase vent emissions

Although this source of emissions can be challenging to characterize, a 2015 study determined that it is a significant source of emissions from gas-fired engines (which may be entirely missing from many equipment-based bottom-up inventories).[93] The same study determined

[92] 5 Colo. Code Regs. § 1001-9-D.H.1.
[93] Johnson et al., "Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities," *Environ. Sci. & Technol.*, 49 (2015), https://pubs.acs.org/doi/pdf/10.1021/es506163m

that the average ratio of crankcase-to-exhaust emission was 14.4% (this ratio is meaningful because crankcase vents are often co-mingled with exhaust streams in the field).

1.5.6. Recommendations

We recommend that the BCER implement the following rules in 2025:

- Revise and lower the emissions standards for smaller reciprocating compressors, accounting for data showing cost-effectiveness of standards <u>for individual units</u> as low as 0.82 cubic meter per hour per throw.
- Lower the threshold for existing centrifugal compressors to match or exceed the proposed EPA requirement.
- Eliminate or significantly constrain the existing exemption in the pneumatic compressor starter provisions §52.07(2) and directly require conservation of compressor blowdown emissions with provisions at least as strong as Colorado's.

Additionally, we recommend that the BCER:

- Evaluate options for control of methane from compressor engine exhaust (slip) in line with the proposed federal regulatory framework.
- Investigate policies to shift compression from gas-fired engines to grid-powered electric motors as part of the development of the regulatory cap on oil and gas emissions.
- Evaluate options for addressing crankcase venting, including routing crankcase vent gas to engine inlets and other approaches commonly utilized for gasoline/diesel engines.

1.6. Require more detailed and measurement-based reporting

To ensure transparency and evaluate compliance, regulations need to be underpinned by a comprehensive reporting framework. Current methane emissions regulations in B.C. require that duty holders report LDAR survey results and repairs made to the BCER.[94] This includes an industry leading requirement to quantify leak emission rates.

There is an opportunity to improve reporting requirements by adopting emerging best practices. In particular, reporting requirements in forthcoming BCER regulations must improve emissions and activity estimates based on equipment counts *and* address pervasive issues of

[94] See B.C. Oil and Gas Comm., Fugitive Emissions Management Guideline VERSION 1.0 : July 2019, https://www.bc-er.ca/files/documents/femp-guidance-july-release-v10-2019.pdf

industry underreporting, which has been shown to under-estimate emissions compared to measurements in many Canadian and U.S. studies.

We recommend that the BCER adopt a detailed measurement protocols, such as those developed by GTI Veritas, and a comprehensive reporting framework, similar to the guidelines in the Oil and Gas Methane Partnership (OGMP) 2.0.

OGMP 2.0 is a voluntary pathway to move from estimating emissions using generic emission factors (level III), to specific emissions and activity factors (level IV), and finally to utilizing site-level and source-level measurements (level V).[95] OGMP 2.0 typically allows firms three years from joining the partnership to move to level IV or level V for operated assets. The European Union (EU) has designed their recent methane emissions regulations around OGMP 2.0, requiring that duty holders submit source- and site-level measurements within two and three years, respectively. [96]

GTI Veritas: The Gas Technology Institute (GTI) in the U.S., in consultation with a wide range of technical experts, recently released the Veritas protocols for measurement and data reconciliation along the natural gas value chain.[97] The objective of the Veritas protocols is to demonstrate emission reductions credibly, consistently, and transparently. These protocols can serve a wide range of needs: certification standards, regulatory compliance, government and company greenhouse gas inventories, and ESG disclosures. Therefore, future measurement requirements for the oil and gas sector in B.C. can also draw on aspects of the Veritas protocols.

Finally, **we recommend strict penalties for not following reporting guidelines**, as is common in some U.S. states including New Mexico, which imposed quarterly reporting requirements in its 2021 emissions regulations.

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[95] United Nations Environment Programme, Oil and Gas Methane Partnership (OGMP) 2.0 Framework (2020), https://www.ccacoalition.org/en/resources/oil-and-gas-methane-partnership-ogmp-20-framework

[96] Proposal for a Regulation of the European Parliament and of the Council on Methane Emissions Reduction in the Energy Sector and Amendment Regulation (EU) 2019/942, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2021%3A805%3AFIN&qid=1639665806476

1.7. Implement more robust compliance and enforcement programs

1.7.1. Super emitter response program

We recommend BCER propose a super emitter response program. EPA recently proposed a new program intended to supplement LDAR inspections and find additional super-emitters that can occur in between routine LDAR inspections. As proposed, the program contains the following elements:

- Third parties, approved by the EPA, may remotely monitor oil and gas facilities for large leaks. EPA proposes a leak threshold of 100 kg/hr.
- Third parties may use remote sensing equipment including aircraft, mobile monitoring platforms, or satellites to detect super-emitters.
- Upon detection of a super-emitter, third parties must notify the owner or operator of the oil and gas facility. The notification must provide detailed information including the location of the emissions, a description of the technology and sampling protocols used to identify emissions, and the date and time of detection and confirmation after data analysis that a super-emitter event was present.
- Third parties must notify the EPA and any delegated state entity of the results of inspections. EPA must make such reports available to the public.
- Owners and operators who receive a notification of detection of a super-emitter event must take swift action to confirm if a super-emitter event occurred at one of their sites, and if so, to remedy it. Specifically, an operator must conduct a root cause analysis to identify the cause of the event. This could include conducting a follow-up investigation with an infrared camera and repairing the source of the leak (e.g., closing a thief hatch on a controlled tank). If the investigation determines that the cause of the event is something other than a malfunction or abnormal emissions, the operator must identify the source of the event in their report to the EPA. For example, a maintenance activity where venting is allowed, could be the source of the event. Operators must commence the root cause analysis within five calendar days of receipt of the third-party report and must conclude any corrective actions within 10 days of notification, unless additional time is necessary, in which case operators have until 30 days from receipt of the notification. Operators must submit a report to the EPA within 15 days of completion of

the root cause analysis and corrective action describing the source of emissions, the corrective actions taken, and the compliance status of the affected facility.[98]

1.7.2. Enforcement using aerial measurements

The BCER should consider using aerial measurements acquired regularly in collaboration with third parties to determine regulatory compliance. For example, equipment-level emissions rates measured with aircraft could be compared to regulatory limits for sources such as compressors and tanks, and action could be taken to inform or penalize operators for their exceedances. To be enforceable, venting limits must be set at similar time scales (e.g., daily or hourly) and as snapshot measurements (e.g., hourly), as current monthly venting limits cannot be used effectively to determine compliance given the high variability in emissions across this time scale.

2. Accelerate the timeline for near-zero oil and gas methane emissions to 2030

The regulatory strengthening discussed above would deliver significant near-term reductions in methane emissions in the oil and gas sector. These near-term reductions will be crucial to reduce the harm caused by methane emissions and demonstrate that B.C. is on pace to meets its commitments to reduce methane pollution and overall greenhouse gas pollution from oil and gas. However, there is still room to go further, and B.C.'s target of near-zero methane emissions from the oil and gas sector by 2035 should be accelerated to 2030. Doing so is essential to protect our climate and achieving a declining cap in oil and gas emissions.

The OGCI has already announced its goal of near-zero emissions by 2030. Given the urgent need to drastically reduce global methane emissions, provincial policy in B.C. should match this level of ambition from industry. It is also our view that near-zero methane emissions by 2030 will be needed to meet the overall 2030 emissions reduction targets for oil and gas sector in B.C.

[98] 87 Fed. Reg. 74702, 74,749 (Dec. 6, 2022).

3. Considerations regarding performance-based standards

Achieving near-zero emissions may require standards that move beyond the work practice and equipment-based regulatory approach that B.C.'s regulations have used to date. It will be valuable for B.C. to consider a number of approaches, such as:

- Overall emissions limits for facilities by facility and production type;
- Taxing methane within B.C.'s carbon pricing system;
- A combined approach that requires operators to pay a fee or tax per ton of methane emitted above a threshold.

We believe that these approaches (or a combination) have the potential to achieve considerable emissions reductions, as long as any such regulations adhere to the following criteria:

- Any standards based on overall emission limits or emissions fees/taxes must be **additional to current and forthcoming** work practice and equipment-based standards, rather than a replacement for those standards. Work practice and equipment-based standards are important because they require a minimum level of emissions control for all sites and are more clearly enforceable.
- Implementation of any **standards** based on overall emission limits or emissions fees/taxes must be **built upon direct measurement** of emissions from sites, not emissions-factor based inventory calculations (due to the aforementioned inaccuracy of inventory estimates based on equipment counts and emission factors).
- Standards based on overall emission limits or emissions fees/taxes must be stringent. Emissions limits must ramp down over time, bringing operators to near-zero emissions as rapidly as possible. Fees must be at least as high as Canada's carbon price, which is set to reach \$170/t CO_2e by 2030, or \$4,250/t CH_4 using a global warming potential of 25.[99] We note that this price is in line with estimates for the social cost of methane, when that cost combines both damages from methane's climate-warming impacts and damages from methane's (non-climate) impacts on air quality.

[99] Govt. of Canada, Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030, https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html

Conclusion

Thank you for your due consideration of these recommendations. We would welcome the opportunity to engage with BCER as methane regulations are developed.