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

Coalition comments and recommendations on proposed regulatory policy

Submitted to: British Columbia Energy Regulator | July 26, 2023

Contact:

Jan Gorski, Pembina Institute
Tom Green, David Suzuki Foundation
Ari Pottens, Environmental Defense Fund
Jonathan Banks, Clean Air Task Force
Robb Barnes, Canadian Association of Physicians for the Environment

Our coalition of leading climate and energy organizations – the Pembina Institute, David Suzuki Foundation, Environmental Defense Fund, Clean Air Task Force and the Canadian Association of Physicians for the Environment – is grateful for the opportunity to further comment on the development of proposed regulations to meet and exceed B.C.'s commitment to reduce methane emissions.

We continue to stress the urgency of ambitious action to rapidly and substantially reduce methane emissions from the oil and gas sector.

B.C's most recent accountability report shows that current policies fall short of meeting the province's 2025 and 2030 climate targets (1.6 Mt CO_2e gap for 2025 and 0.8 Mt for 2030).[1] Given that methane is a potent climate forcer with more than 80 times the warming power of carbon dioxide in a 20-year timespan, developing robust, evidence-based policies to rapidly drive oil and gas methane emissions down to near-zero must remain a top priority. We also know that methane gas escalates air pollution by emitting toxins such as nitrogen dioxides, creating particulate matter and ozone. These are linked to asthma, lung and heart diseases, stroke, dementia, hospitalizations, premature birth risks, and premature deaths.

[1] British Columbia, 2022 Climate Change Accountability Report, https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/2022-ccar/2022_climate_change_accountability_report.pdf

B.C.'s proposed regulatory policy lags leading regulatory best practices in the exceedingly long timelines it proposes for existing facility rules and leaves a key component – compressor engine exhaust – undeveloped. As such, we strongly urge the BCER to strengthen and improve it as outlined below.

We support the following aspects of the planned regulatory approach and urge that they be preserved as the regulations are further developed:

1. **Integrating vital measurement-based information from airplane surveys into climate modeling and regulatory development.** Studies have consistently demonstrated the inaccuracy of bottom-up estimation based on emissions factors, as well as the need for empirical measurement and monitoring.[2] When regulatory development integrates empirical emissions data, regulations will reflect actual emissions, enabling meaningful progress toward reduction targets.
2. **Minimizing non-routine venting and prohibiting routine venting from most sources at new facilities as of 2025.**
3. **Reducing emissions from tanks.** Requiring operators to install thief hatch monitoring systems to quickly identify and alert operators to open hatches and thereby prevent significant tank emissions.
4. **Integrating alternative LDAR pathways** that recognize the rich and rapidly evolving technological landscape for measurement and quantification of methane emissions.
5. **Minimizing emissions from maintenance activities** by requiring operators to control emissions from planned pipeline blowdowns where technically feasible as of 2025.

However, the proposed framework falls far short of national and international best practices in the timelines it sets and is missing crucial pieces. B.C.'s largest emissions source is also the most challenging – compressor exhaust. Since B.C. has not yet proposed a policy approach to deal with this source, we recommend strengthening regulations and timelines for other sources with more established mitigation approaches. Our high-level recommendations are outlined here, with more detailed recommendations in the rest of the document.

1. Speed up timelines for cost-effective solutions at existing facilities to align with best practices in the US.
    a. Non-emitting pneumatics in 2025 instead of 2035 (US EPA proposing 2028)
    b. Stricter limits for uncontrolled tanks in 2025 instead of 2035 (US EPA proposing 2028)

[2] MacKay et al., "Methane emissions from upstream oil and gas production in Canada are underestimated" *Sci Rep* 11, no. 8041 (2021).

2. Increase frequency of measurement based LDAR to monthly to align with best practice in Alberta Peace River region, and U.S. EPA.
3. Enhance comprehensiveness of emissions sources included in prohibition of routine venting for new sources to include separators.
4. Enforce penalties that exceed the cost of compliance.
5. Develop a clear policy approach to address compressor engine exhaust including improved quantification methods and reporting requirements.

1. New facilities and facility amendments

The BCER proposes to prohibit routine venting from compressor seals, pneumatic devices and pumps, production tanks, and dehydrators at new facilities beginning in 2025. It also proposes a "decision tree approach," which integrates considerations of safety, technical feasibility and economic feasibility, and which can be used to justify exemptions to the venting prohibition.

1.1. Remarks

While we support the proposed prohibition on routine venting, we note that the emissions sources listed do not include all sources of concern. To be comprehensive, the regulations should extend to all equipment that feeds into the listed components – including separators, which are responsible for 3% of measured methane in B.C.[3] Additionally, we note that the State of Colorado in the U.S. requires operators of controlled storage tanks to take steps to protect against venting by keeping hatches, pressure relief devices, and other access points closed and latched while measuring for the quantity and/or quality of the liquids.[4]

We also urge that the elements of the decision tree be carefully considered and crafted to avoid generating abundant exemptions that undermine regulatory efficacy. We support the BCER's proposal to use the provincial carbon price (among other metrics) as a benchmark for economic

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

[4] 5 C.C.R. 1001-9 Part B § II.C.4.b.

feasibility, relative to which the cost of abatement is typically small – in fact, a new study finds that a 75% reduction of methane emissions is achievable at an average cost of just $11/t$CO_2$e.[5]

We also encourage the BCER to remove the economic feasibility criteria from its decision tree. Economic feasibility criteria are ripe for abuse, especially if poorly defined. The proposed U.S. EPA rules don't include economic feasibility as a criterion for exceptions. Alberta's economic evaluation for conservation gas in Directive 60 draw the boundary of the economic test around the conservation activity. Economic feasibility should be evaluated from the perspective of the entire oil/gas project.

1.2. Recommendations

We recommend that the BCER:

- Extend the prohibition on routine venting at new facilities to all sources of concern, including separators.
- Prohibit non-routine venting from pneumatics and pumps at new facilities.
- Ensure that all sources of emissions that have solutions are included in the definition of routine venting from tanks. This should include flashing, breathing, and working losses, as well as gauging and loadout. On new tanks, operators should be required to install equipment for gauging or sampling of liquids without opening the hatch, similar to what is required in Colorado.[6]
- Remove the economic feasibility criteria from the decision tree to align with best practices including the U.S. EPA's proposed rules.

2. Existing facilities

The BCER proposes to extend the requirements for new facilities to existing facilities in 2035.

[5] Dunsky Energy + Climate Advisors, Canada's Methane Abatement Opportunity: A Marginal Abatement Cost Curve for Methane Emissions in Canada's Upstream Oil & Gas Sector, https://www.edf.org/sites/default/files/2023-07/Canada%20Methane%20Abatement%20Opportunity.pdf?_gl=1*1pkktkd*_ga*ODI0NjQ3Mzg2LjE2ODAwNDI4MzM.*_ga_2B3856Y9QW*MTY4OTk3NDg2OC40Ny4wLjE2ODk5NzQ4NzAuNTguMC4w*_ga_Q5CTTQBJD8*MTY4OTk3NDg2OS40Ny4wLjE2ODk5NzQ4NzAuNTkuMC4w*_gcl_au*NjI3MzYxMzY5LjE2ODgwNDQzNDM

[6] See 5 C.C.R. 1001-9 Part B § II.C.4.b (owners or operators of controlled tanks at new or expanded sites "must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage tank(s)").

A recurring theme in the subsequent sections of our commentary will be that national and international best practices have established significantly faster timelines for phasing out emitting equipment, prohibiting routine venting, and strengthening operational requirements to drive down methane emissions swiftly and substantively. Leading states such as Colorado and New Mexico have comparable rules already in force and are actively enforcing them,[7] and the U.S. EPA nationwide rules are proposed to be fully implemented in 2028.[8]

We will outline specific recommendations for the individual elements of the proposed methane policy below. Our overall conclusion is that the evidence, the economics, the best regulatory practices, and the gap in B.C.'s 2025 and 2030 climate targets motivate extending strengthened regulations to existing facilities much sooner than 2035.

While B.C. has proposed some strong rules ahead of 2030, there are still remaining cost-effective opportunities in pneumatics, tanks, and LDAR. These are needed to achieve B.C.'s methane targets and fill the gap to its economy wide 2025 and 2030 targets, especially given that B.C. has not yet proposed policy to achieve the largest portion of reductions assumed in its modelling – compressor exhaust emissions.

The regulatory strengthening discussed below 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 health and climate harm caused by methane emissions and demonstrate that B.C. is on pace to meet its commitments to reduce methane and overall greenhouse gas pollution from oil and gas. However, it is both feasible and necessary to accelerate B.C.'s target of near-zero methane emissions from the oil and gas sector by 2035 to 2030. Doing so is essential to protect our climate and achieving a declining cap in oil and gas emissions.

The industry-led Oil and Gas Climate Initiative 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 at least 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 the oil and gas sector in B.C.

[7] Fortune, New Mexico fine oil company $40 million for burning off massive amounts of natural gas *(*(June 30, 2023), https://fortune.com/2023/06/30/new-mexico-fines-oil-company-ameredev-40-million-burning-off-natural-gas/; Carlsbad Current Argus, Six oil and gas companies fined by New Mexico for air pollution. Here's what we know (April 8, 2023), https://www.currentargus.com/story/news/2023/04/08/six-oil-and-gas-companies-fined-by-new-mexico-for-air-pollution/70090081007/

[8] 5 Colo. Code Regs. § 1001-9; N.M. Code R. § 19.15.2.1-19.15.112.14; 87 Fed. Reg 74702 (Dec. 6, 2022).

2.1. Pneumatic pumps and devices

Pneumatic pumps and devices are a significant source of methane pollution. Recent field studies in B.C. indicate that pneumatic controllers and pumps are responsible for about 20% of methane emissions.[9]

We therefore support the BCER's plan to eliminate emissions from pneumatic pumps and devices at new facilities as of 2025. For existing facilities, however, we stress that zero-emitting alternatives[10] are both economical and readily available. Our analysis, based on the EPA's Technical Support Document for its proposed rules,[11] shows that for existing production facilities:

- Zero-bleed electric-powered controller installations are cost-effective for all facility size classifications with a range of $236 to 380 CAD/metric ton ($9 to 15 CAD/ton CO_2e) abated methane emissions.
- Zero-bleed compressed air systems are cost-effective for medium and large facilities, with a range of $897 to $1,716 CAD/metric ton ($36 to 69 CAD/ton CO_2e) abated methane emissions.
- 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.
- Zero-bleed electric-powered pumps are cost-effective, with a range of $153 to $1,394 CAD/metric ton ($6 to 56 CAD/ton CO_2e) methane abatement.

Moreover, a 2016 study shows that cost-effective zero-bleed options exist for existing pneumatic devices, even where grid power is not being used at the site. These options have proven effective in upstream oil and gas operations in Canada and more broadly in North

[9] 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, no. 14 (2021).

[10] When we say "zero-emitting" in this document, we include controllers where the emissions are collected and routed to a gas-gathering flow line or collection system to a sales line, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve (*i.e.,* generally characterized as ''routing to a process''); and (2) self- contained natural gas pneumatic controllers. Notably, zero-emitting does not include routing to a combustion device as those are known to emit methane. Additionally, any detected emissions from these gas-driven controller would be a violation of any zero-emitting requirement.

[11] 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).

America.[12] A 2023 report finds that there is a robust supply chain with 40 well-established providers of zero-emissions equipment to replace polluting pneumatic controllers.[13]

Fast and comprehensive action on pneumatic pumps and devices is not only an impactful way to reduce methane emissions but a practically feasible one. We therefore urge the BCER to move up its timeline for the prohibition of routine venting at existing facilities.

2.1.1. Best practices

Several Canadian and U.S. jurisdictions require the near-term phase-out of emitting pneumatic pumps and devices for existing facilities, with the strongest leaders having already required phase-out.

- **ECCC:** The regulatory framework that is informing the development of draft regulations propose requiring all pneumatic pumps and devices to be non-emitting or capture emissions, with the timeline for implementation yet to be specified but certain to be prior to 2030.
- **U.S. EPA:** Draft regulations propose requiring zero-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 zero-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 submittals (by 2028).
- **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 significant portion of their facilities to non-emitting controllers by May 2022 and were required to complete additional conversion by May 2023. Moreover, the state is considering strengthening this requirement as it seeks to reduce ozone-precursor VOC emissions from oil and gas facilities.
- **New Mexico:** Requiring an increasing proportion of controllers be non-emitting, with 65 to 85% non-emitting required by 2027 and 80-90% non-emitting required by 2030.[14]

[12] Carbon Limits, Zero Emission Technologies for Pneumatic Controllers in the USA: Applicability and cost effectiveness (2016), https://www.catf.us/resource/zero-emission-technologies-for-pneumatic-controllers-usa/
[13] Datu Research, Zero-emission Alternatives to Pneumatic Control: How Ready are Technology Providers to Meet Increased Demand? (Jan. 2023), https://cdn.catf.us/wp-content/uploads/2023/01/30114854/Datu-Alternatives-to-Gas-Pneumatics.pdf

[14] N.M. Code R. § 20.2.50.122

2.1.2. Remarks

The BCER's proposed 50% reduction of emissions from pneumatic devices at existing facilities by 2030 falls considerably short of regulatory best practices given the cost effectiveness of these reductions and the range of solutions to achieve such reductions.

2.1.3. Recommendations

We urge that the BCER align with international best practices to:

- Require all existing pneumatic devices and pumps to be zero-emitting or to capture their emissions by 2025.

2.2. Compressor seals

Emissions from the seals for moving parts on compressors include venting from rod-packing seals for reciprocating compressors and emissions from centrifugal compressor seals. Leaks from compressor seals can contribute significantly to methane emissions. A 2015 study of natural gas compressor stations and storage facilities showed that, next to engine exhaust, vents from compressor seals (or "compressor packaging") were the second greatest contributor to overall methane emissions.[15] Effectively regulating emissions from compressor seals is therefore crucial.

2.2.1. Best Practices

2.2.1.1. Reciprocating compressors

- **ECCC:** As of Jan 1, 2023, existing reciprocating compressors are subject to a vent limit of 1.38 m^3/hr/throw.

2.2.1.2. Centrifugal compressors

- **U.S. EPA:**

  Existing wet seal: proposed emissions standard of 3 scfm (0.08 cubic meter per minute).

  All dry seal: proposed emissions standard of 3 scfm (0.08 cubic meter per minute).

[15] 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.

2.2.2. Remarks

2.2.2.1. Reciprocating compressors

We support the proposed reduction of the upper limit on B.C.'s fleet average to 0.3 m^3/hr/throw. However, we reiterate that including large, controlled compressors in the calculation of fleet averages skews the average down and compromises regulatory efficacy. Moreover, the proposed maximum of 3 m^3/hr/throw for individual units remains too high.

CATF estimates that imposing a 0.82 m^3/hr/throw 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.[16]

2.2.2.2. Centrifugal compressors

The BCER's proposed regulation for compressor seals applies only to reciprocating compressors and excludes explicit mention of centrifugal compressors. Existing regulations for centrifugal compressors should be updated and improved to align with regulatory best practices.

2.2.3. Recommendations

While maintaining the prohibition on routine venting effective for new facilities in 2025 and for existing facilities in 2035, we recommend that the BCER implement the following rules for existing facilities in 2025:

2.2.3.1. Reciprocating compressors

- Revise and lower the maximum emissions standards for reciprocating compressors to 0.82 m^3/hr/throw.
- Exclude large, controlled compressors from the calculation of fleet average to avoid skewing the average down and compromising regulatory efficacy.

2.2.3.2. Centrifugal compressors

- Match the U.S. EPA's proposed emissions standard of 3 scfm (0.08 cubic meter per minute) for existing wet seal and all dry seal centrifugal compressors.

[16] *Id.*. See also https://www.pembina.org/reports/2023-03-submission-bc-methane-regs.pdf

2.3. Compressor engine exhaust

In B.C., compressors are the most frequently detected source category and by far the single greatest contributor to measured methane emissions, representing 54% of measured emissions.[17] Recent studies have demonstrated that methane slip from natural gas-fired centrifugal compressors is a considerable source of methane emissions. Innovative, forward-looking policies that leverage the wide variety of available technological solutions are needed.

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.

2.3.1. Best practices

- 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.

2.3.2. Remarks

We support the BCER's ambitious proposal to reduce emissions from compressor engines by 0.31-0.38 Mt. However, we are concerned that the proposal is not yet backed up by a well-defined policy approach. We emphasize the need for clear policies and pathways to bring the proposed reductions to fruition. Until one such pathway is developed, the proposed reductions remain merely aspirational.

We recognize that federal Multi-Sector Air Pollutants Regulations have had the unintended effect of placing vital air quality protections effectively at odds with equally vital methane reductions.[18] They have created a regulatory pressure to switch from rich-burn compressor engines, which have comparatively higher NO_x emissions and lower methane emissions, to lean-burn engines, which produce lower NO_x but typically will have higher methane emissions. Additional regulation must carefully navigate the existing policy context without placing these independently important concerns further at odds.

[17] Johnson et al., "Origins of Oil and Gas Sector Methane Emissions."

[18] Multi-Sector Air Pollutants Regulations (SOR-2016-151), https://laws-lois.justice.gc.ca/eng/regulations/SOR-2016-151/index.html

A performance standard in the form of a fleet average requirement should be introduced and supported by strong monitoring, reporting, and verification requirements. Such a standard should also be paired with innovative regulatory pathways that integrate the rich variety of available technological solutions.[19] Those solutions include options for retrofitting, tuning, updating air-fuel controls, replacing injection systems, and adding post-combustion control. There is also significant variation among lean-burn engines, with some varieties emitting significantly less methane than others. Sound policy should integrate these options and alternatives, while crediting operators for electrifying compressors, as discussed below.

Regulations for compressor engines should also leverage and further advance ongoing electrification. Electric motors completely eliminate methane slip while having the vital co-benefits for carbon dioxide and other pollutants. Given the low carbon intensity of grid electricity in B.C., electrification greatly reduces the overall carbon dioxide emissions (in addition to NO_x emissions) associated with compression. Roughly one quarter of compressor engines in B.C. are already electrified, and compliance with federal and provincial regulatory caps on oil and gas emissions will require still further engine electrification. However, since access to transmission lines can be a barrier and since electrification takes time, policy solutions that advance electrification should complement more swiftly and comprehensively implementable options. Years-off plans for electrification should *not* be an excuse for operators to not utilize cost-effective means of reducing methane slip which can be implemented in the short term.

We support the continued inclusion of methane combustion slip in B.C.'s carbon pricing system. However, there is still an inconsistency between B.C.'s methane model, which includes up-to-date science on methane emissions, and industry reported values. B.C.'s model shows 2021 methane emissions from compressor exhaust and flares to be 1.32 Mt CO2e, while industry reported data shows 0.37 Mt CO2e from those source categories. We urge the BCER to update the applicable quantification methodology to bridge the gap. While measurement and verification are essential for emissions sources prone to super-emitting events, compressor engines have a relatively consistent rate of slip at a given operating condition. Instead of one single emission factor, which B.C. currently requires in its quantification methodology, engine specific factors should be used. Emission factors based on engine specifications should be used when appropriate.

Finally, we urge the BCER to consider developing regulations for crankcase vent emissions. Although this source of emissions can be challenging to characterize, a 2015 study determined

[19] Johnson et al., "Origins of Oil and Gas Sector Methane Emissions."

that it is a significant source of emissions from gas-fired engines (which may be entirely missing from many equipment-based bottom-up inventories).[20] The same study determined 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). Therefore, crankcase vent emissions should be accounted for and meaningfully addressed.

2.3.3. Recommendations

We recommend that the BCER consider the following policy options for implementation, as of 2025:

- Consider introducing a performance standard in the form of a fleet average requirement, based on high-quality data regarding compressor engine methane emission rates (including crankcase venting).
- Given that compressors are the single largest methane emissions source in BC and will remain so in 2030, we recommend BC improve its understanding of compressor methane emissions by:
    - Updating industrial reporting methodologies to require companies to report engine and compressor combustion emissions based on engine specifications, not generic emission factors.
    - Requiring companies to submit a detailed compressor inventory if they do not have to do so already.

2.4. Tanks

Cutting-edge methane measurement and quantification research shows storage tanks to be a far greater contributor to methane emissions than was previously believed. The most up-to-date evidence shows that in B.C., compressors and tanks are the two most frequently detected source categories and the two largest contributors to measured methane emissions, with tanks representing 18% of measured emissions.[21] Storage tanks are therefore one of the most important pieces of the methane policy puzzle. Both controlled and uncontrolled tanks can emit significant amounts of methane. The most recent aerial study in B.C. found that 31% of production tanks are uncontrolled.[22]

[20] Johnson et al., "Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities"

[21] Matthew R. Johnson et al., "Origins of Oil and Gas Sector Methane Emissions”.

[22] *Id.*

2.4.1. Best practices

- **U.S. EPA:** Since 2011, EPA has required that all new tanks with the potential to emit volatile organic compounds (VOC) exceeding 6 short tons per year (TPY)[23] reduce these emissions by 95%. The EPA's draft regulations also propose that existing storage tanks or tank batteries with a potential to emit 20 TPY of methane must also reduce emissions by 95% by 2028.[24] These rules also include substantial inspection, performance, and compliance requirements.
- **Colorado:** All new and existing tanks with actual uncontrolled emissions of 2 TPY of VOC (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.[25] 98% control is required when a combustor is used instead of vapour capture. Open flares are not generally allowed.[26]
- **New Mexico**: All new or modified tanks with the potential to emit 2 TPY of VOC upon start-up must reduce emissions by 95%.[27] 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 VOC at single tank batteries, must also reduce emissions by 95% by 2029.[28] For all tanks, if combustion control devices are used, tanks must have a minimum design combustion efficiency of 98%.[29]
- **California**: Operators must collect and use (or destroy) methane and associated gases from uncontrolled storage tanks with emissions above a set methane standard.[30]

2.4.2. Remarks

The BCER underestimates the magnitude of the problem posed by uncontrolled tanks and sets too distant a timeline for the elimination of routine venting from existing tanks as compared

[23] 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.

[24] 87 Fed. Reg. 74702, 74800 (Dec. 6, 2022).

[25] 5 Colo. Code Regs. § 1001-9-D.II.C.

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

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

[28] *Id.* at § B.(1).

[29] *Id.*

[30] In particular, 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 vapour collection system (CARB: 17 Cal. Code Regs § 95668.(a)(6),(7)).

with regulatory best practices. Evidence suggests that emissions from uncontrolled tanks are considerable, with 31% of tanks in BC being uncontrolled.[31] Preventing the escape of saleable gas perennially makes good economic sense, and there is every reason to act ambitiously to address this emissions source.

For controlled tanks, the BCER should follow California's best practice requiring the capture of vented tank emissions. Where feasible, operators should be required to capture and either use or sell captured gas. The benefits of capturing gas are multifold, including 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.

Only when capture and use or sale is demonstrably infeasible should destruction via enclosed combustion be employed. Since combustion slip is a significant contributor to methane emissions, where combustion is necessary, stringent standards for destruction and removal efficiency (DRE) are crucial. Additionally, flare failure (poor or no combustion) has commonly been observed from oil and gas sites.[32] Equipment fail-safes (*i.e*. auto-ignitors), as well as robust monitoring and inspection requirements should be employed. Open flares for tank emissions should be prohibited outright.

2.4.3. Recommendations

We urge the BCER to demonstrate leadership in this important area by implementing the following recommendations:

- As of 2025, align with Colorado's best practice for existing uncontrolled storage tanks emitting 2 TPY of VOC (about 0.3 tons of methane, according to U.S. EPA data, or 34 m^3/month) or greater by subjecting them to a 95% emissions control limit, with extensive inspection, performance, and compliance requirements.[33] The proposed U.S. EPA rules would come into effect in 2028 and New Mexico's rules come into force in 2029.
- Combustion should be allowed only where operators demonstrate that capture and on-site use or sales are infeasible. Following Colorado and New Mexico, specify a 98% DRE

[31] Johnson et al., "Origins of Oil and Gas Sector Methane Emissions."

[32] *Id.*

[33] 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.

for all enclosed combustors and require auto-igniters or continuous monitoring of pilots, as well as frequent operator inspections, at all combustors.

- Prohibit open flares for control of tank emissions.

2.5. Pipeline blowdowns

Significant methane emissions result from both routine and non-routine equipment blowdowns, which are used to relieve pressurized gases from systems before maintenance work or shutdown. In addition to changing management processes to reduce blowdown frequency and volumes, approaches have been identified to conserve and utilize gas when blowdowns occur, or control methane emissions via combustion when that is not possible.

2.5.1. Best practices

- **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).

2.5.2. Remarks

We commend the BCER for requiring, by 2025, that all facilities must control planned pipeline blowdowns and new facilities must demonstrate that non-routine sources of venting – including non-routine pipeline blowdowns – are minimized. Non-routine venting should likewise be minimized at existing facilities by 2025. We also note that the BCER's proposed regulations do not explicitly address compressor blowdowns, but since the engineering principles behind pipeline and compressor blowdown systems are the same, the rules that apply to the one can be extended to the other.

2.5.3. Recommendations

- By 2025, require existing facilities to demonstrate that non-routine sources of venting such as pipeline blowdowns are minimized, similar to the requirement for new facilities.
- Extend regulations for routine and non-routine pipeline blowdowns to compressor blowdowns.

2.6. Leak detection and repair (LDAR)

A large body of measurement-based studies has found higher oil and gas methane emissions than is estimated in official inventories.[34] Bottom-up approaches greatly underestimate emissions because they are based on assumptions that do not account for super-emitting events caused by malfunctions and other abnormal conditions.[35] Field studies have shown that methane emissions in Canada and the U.S. are consequently underestimated by 1.5-2x.[36] Robust LDAR requirements are therefore indispensable for accurate emissions accounting, reducing fugitive emissions, and meeting climate targets.

2.6.1. 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 fugitive methane emissions. Recognizing this, many jurisdictions now require frequent, comprehensive instrument-based inspections at most or all production, processing and compression sites:

- **ECCC:** The proposed regulatory framework would require monthly inspections of all facilities, including single wellheads, as well as annual inspections of non-producing wells and measurement of detected emissions.

[34] Lyon et al., "Constructing a spatially resolved methane emission inventory for the Barnett Shale region" *Env. Sci. Tech.* 49 (2015); Zavala-Araiza et al., "Reconciling divergent estimates of oil and gas methane emissions" *Proc. Natl. Acad. Sci.* 112 (2015); Zavala-Araiza et al., "Super-emitters in natural gas infrastructure are caused by abnormal process conditions" *Nat. Comms.* 8 (2017); Zimmerle et al., "Methane emissions from the natural gas transmission and storage system in the United States" *Env. Sci. Tech.* 49 (2015); Omara et al., "Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale region" *Env. Sci. Tech*. 50 (2016); Peischl, J. et al., "Quantifying atmospheric methane emissions from Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions" *J. Geo. Res. Atmospheres* 120 (2015); Caulton et al., "Importance of super emitter natural gas well pads in the Marcellus Shale" *Env. Sci. Tech.* 53 (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" *Sci. Adv.* 6 (2020); Lyon et al., "Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic" *Atmos. Chem. Phys.* 21 (2021); MacKay et al., "Methane emissions from upstream oil and gas production in Canada are underestimated."

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

[36] Chan 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 & Technology* 54 , no. 23 (2020); MacKay et al., "Methane emissions from upstream oil and gas"; Rutherford et al., "Closing the methane gap".

- **Alberta (Peace River region):** Operators are required to conduct monthly instrument-based LDAR surveys at high-risk sources including storage tanks, flare ignitors/pilots and compressor seals, and must quantify all leaks that are not repaired within 24 hours.[37]
- **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.[38]
- **California**: Requires quarterly instrument-based inspections of all well sites, gathering and boosting compressor stations and transmission compressor stations.[39]
- **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.[40] Compressor stations with potential VOC emissions of 25 TPY or more must also conduct quarterly inspections.[41]
- **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.[42] 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/or processing equipment.[43] 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 audial-visual-olfactory (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. The U.S. EPA also proposed a survey matrix for alternative technology (i.e., non-OGI) screening where the frequency of inspections depends on the minimum detection threshold of the alternative technology.
- **U.S. EPA on inactive wells**: Finally, EPA's proposal requires ongoing fugitive monitoring, recordkeeping, and reporting until all wells at a well site or centralized

[37] 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
[38] 5 Colo. Code Regs. § 1001-9-D.II.E.4.
[39] 17 Cal. Code Regs. § 95669.
[40] NM Admin. Code § 20.5.20.116.
[41] *Id.*
[42] 87 Fed. Reg. 74702 (Dec. 6, 2022).
[43] See 87 Fed. Reg. 74702, 74735 (Dec. 6, 2022).

production facility are properly closed, including a post-closure OGI inspection to demonstrate that plugging has been effective.

2.6.2. Remarks

In requiring OGI quarterly at large facilities and annually at other facilities, the BCER's proposed regulatory policy does not meet best practices for LDAR frequency. The federal government's proposed regulatory framework sets the bar for ambitious LDAR regulation by mandating monthly inspections at all sites. The BCER should match the ambition of the federal approach.

B.C.'s proposed regulatory approach also sets too low a standard for the inspection of inactive wells. Inactive wells are another potentially vastly underestimated source of methane emissions. A study comparing emissions from active and inactive wells found that inactive sites regionally accounted for roughly 43% of total measured methane emissions in Lloydminster. The authors conclude that inactive sites have significant emission reduction potential and recommend that regulations be extended to them.[44] Moreover, researchers studying regulatory efficacy in B.C. found that AVO and other non-instrument-based screening methods are unreliable methods of leak detection.[45] Inactive wells should therefore be subject to regular, instrument-based inspections until properly plugged.

2.6.3. Recommendations

We recommend that as of 2025, the BCER:

- Align with proposed federal methane regulations by requiring monthly LDAR at all facilities while explicitly mandating instrument-based detection methods.
- If a monthly instrument-based LDAR requirement is determined to be practically infeasible, follow the EPA and Alberta (Peace River) model by extending the requirement to facilities determined to be high-risk based on presence of equipment frequently associated with leaks and malfunctions, such as tanks or separators, while extending a quarterly requirement to lower-risk facilities.
- Align with proposed federal methane regulations by requiring annual LDAR at non-producing wells, while explicitly mandating instrument-based detection methods.

---

[44] Vogt, J, et al. "Active and inactive oil and gas sites contribute to methane emissions in western Saskatchewan, Canada" *Elem Sci Anth* 10, no. 1 (2022), https://doi.org/10.1525/elementa.2022.00014

[45] Marie France Johnson et al., "Assessing the effectiveness and efficiency of methane regulations in British Columbia, Canada" *Climate Policy*, (2023), 10.1080/14693062.2023.2229295

3. Compliance and enforcement

We appreciate the BCER's collaborative, evidence-based, good-faith approach to strengthening its regulatory framework for oil and gas methane. However, we urge the BCER to implement strong compliance and enforcement programs to ensure its methane regulations are truly leading, comprehensive, and effective. A recent study of the regulatory efficacy of B.C.'s existing methane regulations showed that low rates of compliance are one of the greatest present barriers to effective methane regulation in B.C.[46]

We recommend that BCER propose a super-emitter response program. The U.S. EPA recently proposed a new program intended to supplement LDAR inspections and find additional super-emitters that can occur in between routine LDAR inspections. The proposed 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 pre-approved 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, 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. The 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

[46] *Id.*

> 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.[47]

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. Without strong enforcement mechanisms in place, there is no reason to assume there will be complete compliance with the regulations and thus no reason to assume the regulations will achieve their targeted reductions.

Conclusion

Thank you for your due consideration of these recommendations.

[47] 87 Fed. Reg. 74702, 74,749 (Dec. 6, 2022).