Reducing methane emissions from Canada's oil and gas sector

Coalition comments and recommendations

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Recommendations

1. Set stronger standards for 2025

- Stronger venting and flaring limits (including stronger performance standards and more accurate emissions measurement)
- Stronger leak detection and repair requirements
- No emissions from pneumatic equipment
- More detailed emissions reporting

2. Implement policy to reduce oil and gas methane to near-zero levels by 2030
3. Establish a Global Centre of Excellence on methane detection and elimination

Thank you for the opportunity to provide comments on the development of new policy to meet and exceed Canada's commitment to address methane emissions. 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 federal government has committed to reducing emissions 40–45% below 2005 levels by 2030. The oil and gas sector is the largest source of GHG emissions, making up 26% of Canada's greenhouse gas emissions in 2019, and must do its fair share of emissions reductions. To achieve this 2030 target, short-term emissions reductions in the sector must be prioritized. Therefore, these methane regulations are critical to achieving rapid GHG reductions in the oil and gas sector, and Canada's overall emissions goals.

We commend the federal government for committing to cap greenhouse gas emissions from Canada's oil and gas industry. Vital to the success of this policy will be reductions in methane emissions, and we are pleased to see the federal government showing leadership by:

- Committing to reduce methane emissions from the oil and gas sector by at least 75% (below 2012 levels) by 2030.
- Signing the Global Methane Pledge at COP26, which aims to reduce global methane emissions 30% below 2020 levels by 2030.
- Committing to establish a Global Centre of Excellence for methane detection and elimination.

Canada's 2030 Emissions Reduction Plan, released March 2022, also highlights methane as the foundation of the government's near-term plans to reduce greenhouse gas emissions in the oil and gas sector. Addressing methane is low cost and much can be done using existing technologies already required in other jurisdictions. 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.[1] Action on methane will keep Canada (and Canadian technology providers) at the forefront of global methane mitigation efforts and the innovative technology that supports that mitigation. In this submission, **we urge Canada to:**

- Strengthen methane regulations for the oil and gas sector with new rules applicable early in 2025 to facilitate crucial interim reductions during this decade.
- Adopt further measures that will achieve near-zero methane emissions in the oil and gas sector by 2030. In doing so, the government would match the level of ambition for methane emissions reduction already set out by the Oil and Gas Climate Initiative, a global consortium of companies representing 30% global oil and gas production.

The urgency — and opportunity — of ambitious action on methane

Methane is a potent greenhouse gas with more than 80 times the climate warming impact of carbon dioxide; it is thus imperative to rapidly and aggressively reduce global methane emissions, to reduce the pace and amount of global warming. As noted above, tackling methane represents one of few early opportunities for rapid, deep emissions reductions in the oil and gas

[1] 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

sector. While other mitigation actions will remain important to overall greenhouse gas emissions reductions in the oil and gas sector for 2030, they are not practicable to achieve the rapid and deep cuts to emissions by mid-decade. Reducing methane emissions generated by oil and gas production is one of the most cost-effective and feasible measures to rapid greenhouse gas reductions in the near term. Methane is one of the industry's principal products, and mitigating emissions typically means implementing measures that essentially keep methane 'in the pipe' rather than letting it escape.

Addressing methane emissions in the oil and gas sector is more essential than ever. The latest IPCC Assessment Report 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 from 2019 levels by 2030. Yet the global trend is currently in the wrong direction: measurements of atmospheric methane concentrations show that both 2020 and then 2021 set records for annual increases in methane concentration.[2]

Canada's current standards on oil and gas sector methane emissions are not in line with established best practices. The United States Environmental Protection Agency (EPA) has proposed draft regulations that will be well ahead of Canada's regulations. Additionally, several U.S. states already have regulations in force that go well beyond Canadian standards, and in some cases, well beyond the EPA's proposed standards. Given the urgency of reducing methane emissions and the importance of showing progress within the oil and gas sector towards its 2030 target, Canada must move rapidly and update its regulations to align with these established regulatory approaches.

Canada must also move further in reducing harmful methane emissions. The Oil and Gas Climate Initiative, a group of the twelve major global oil and gas companies, has pledged to **achieve near-zero methane emissions** by 2030.[3] This should be the goal of the Canadian government as well, to maintain global leadership, and ensure that its oil and gas sector can meet its 2030 target.

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[2] 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

[3] 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/

Recommendations

1. Set stronger standards for 2025

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

This strengthening of regulations should include:

- stronger venting and flaring limits backed by robust measurement, monitoring, and reporting rules
- standards requiring that leak detection be carried out more frequently and at all industry sites, and using the full spectrum of technologies (i.e., ground-based oil and gas imaging, drones, towers and aerial screening) to ensure prompt detection of leaks
- replacement of venting, gas-driven pneumatic controllers and pumps with non-emitting alternatives.

Fast implementation of these measures is appropriate because they are proven, require only on-the-shelf technology, and are already in place elsewhere (as detailed below).

It is still likely that, under the current regulatory framework, Canada'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.[4, 5, 6, 7] A recent study in British Columbia conducted by the B.C. Methane Emissions Research Collaborative (MERC) shows that most of the extra emissions come from storage tanks, compressors and unlit flares, which account for more than half of all methane emissions in the sector.[8] These additional sources of emissions

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[4] 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

[5] 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

[6] 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

[7] 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

[8] David Tyner and Matthew Johnson. "Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data," *Environmental Science and Technology* 55, no. 14 (2021). https://pubs.acs.org/doi/10.1021/acs.est.1c01572

are not captured in Canada's National Inventory Report and are not effectively managed by current provincial regulations.

These emissions were present in the baseline year (2012). The addition of this substantial set of emissions to the baseline inventory — coupled with the fact that these sources are not effectively addressed by the current provincial regulations — indicates that Canada will fall short of its 2025 target, unless changes to the regulatory framework are introduced.

1.1 Stronger venting and flaring limits

The practice of venting is responsible for a significant amount of Canada's methane emissions, and studies consistently show that vented emissions are underreported.[9] One 2017 field study in Alberta found that emissions from venting in the province could be up to 2.5 times higher than reported.[10] Mitigating emissions from venting and flaring is also especially low-cost, with costs well below the federal carbon price (no more than \$11/t CO_2e).[11] A 2019 study from the Canadian Energy Research Institute (CERI) shows that venting can be mitigated for less, under \$5/t CO_2e.

A recent study in British Columbia found that 23% of methane emissions in the province resulted from unlit flares.[12] This indicates that flares should be inspected frequently for flame-outs and equipped with auto ignitors.

Finally, we note that Canada is a signatory to the World Bank's *Zero Routine Flaring by 2030* initiative and should align venting and flaring regulations to achieve this commitment.[13]

1.1.1 Stronger performance standards

Some North American jurisdictions have already implemented or proposed ambitious limits on venting and flaring of associated/casinghead gas and venting from storage vessels:

- **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

[9] MacKay, "Methane emissions from upstream oil and gas production in Canada are underestimated."

[10] Johnson, "Comparisons of Airborne Measurements and Inventory Estimates of Methane Emissions in the Alberta Upstream Oil and Gas Sector."

[11] David Tyner and Matthew Johnson. "A Techno-Economic Analysis of Methane Mitigation Potential from Reported Venting at Oil Production Sites in Alberta," *Environmental Science and Technology* 52, no. 2 (2018). https://doi.org/10.1021/acs.est.8b01345

[12] Tyner, "Where the Methane Is."

[13] World Bank, "Zero Routine Flaring by 2030." https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030

conservation rates at heavy oil and bitumen wells and facilities must exceed 95%.[14] For comparison, the average conservation rate at all non-thermal operations in Alberta in 2020 was only 89%.[15]

- **U.S. EPA:** recently proposed the prohibition of routine venting of associated gas at all wells. Additionally, since 2011, the EPA has required that all new tanks with volatile organic compounds (VOC) emissions in excess of 6 short tons[16] per year (TPY) reduce these emissions by 95%. (EPA estimates that typically, a tank emitting 6 TPY of VOC is emitting less than 1.5 TPY of methane.) The EPA has proposed that existing storage tanks or tank batteries with a potential to emit of 20 TPY of methane must also reduce emissions by 95%. All pollution control equipment is subject to regular leak detection and repair (LDAR) inspection requirements.
- **Colorado:** prohibits routine venting or flaring of associated gas from all wells. Additionally, all new and existing tanks with actual uncontrolled emissions of 2 TPY of VOC (typically, about 0.5 tons of methane, according to U.S. EPA data) or greater are subject to a 95% emissions control limit. 98% control is required when a flare is used instead of vapor capture. Auto igniters are also required for any flare, to prevent flame-outs (where the flame goes out and the methane is vented).
- **New Mexico:** prohibits routine venting and flaring of gas from wells. In addition, all new or modified tanks with the potential to emit 2 TPY of VOC upon start-up must reduce emissions by 95%. 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%. For all tanks, combustion control devices, if used, must have a minimum design combustion efficiency of 98%.

As a first step towards eliminating venting and flaring by 2030, we recommend that Canada implement these best practices in 2025:

- Eliminate routine venting and flaring[17] of associated/solution/casinghead gas at all wells. This will align with existing best practices in other jurisdictions including the Peace River region of Alberta (as outlined above) and conform with Canada's international commitments.

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[14] 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

[15] Alberta Energy Regulator, *Upstream Petroleum Industry Emissions Report* (2022). https://static.aer.ca/prd/documents/sts/ST60B-2021.pdf

[16] 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.

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

- Implement standards limiting venting from storage tanks, in line with standards for Colorado and New Mexico.
- Design standards to require or incentivize operators to capture rather than combust methane from tanks, unless doing so is infeasible.[18] We recommend that operators should 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 flares or combustion devices) be allowed. The benefits of capturing gas are multifold: reduced emissions of methane and other air pollutants, reduced wasted gas resulting in additional natural gas sales (increasing revenue for operators and royalties for governments), and alignment with Canada's commitment to the World Bank's *Zero Routine Flaring by 2030* initiative.
- Specify a 98% destruction and removal efficiency (DRE) for all combustors and flares, and require auto-igniters at all flares.

1.1.2 More accurate emissions measurement

For any venting sources that are not eliminated through the above regulatory changes, better measurement should be required to improve the accuracy of vented amounts. The most straightforward way to achieve this is to require operators to measure (rather than estimate) gas production and vented volumes. Current reporting protocols require infrequent testing of the gas-to-oil ratio (GOR) at facilities which is then used to report production estimates, with vented volumes calculated from production estimates. However, data from Alberta demonstrates that gas production is highly variable.[19] Accordingly, GOR measurements can vary significantly depending on when the GOR test is carried out.

To address this problem, we suggest operators be required to directly measure, rather than estimate, all vented or flared gas volumes.

1.2 Stronger leak detection and repair (LDAR) requirements

Leaks and other unintended emissions which arise due to upset conditions or malfunctions are a significant source of methane emissions at oil and gas facilities. Numerous studies utilizing direct measurements show that equipment leaks are unpredictable, mutable, and

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[18] 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 C.C.R. Section 95668.(a)(6),(7)).

[19] J. R. Roscioli, et al., "Characterization of Methane Emissions from Cold Heavy Oil Production with Sands (CHOPS) Facilities," *Journal of the Air and Waste Management Association* 68, no.7 (1995). http://dx.doi.org/10.1080/10962247.2018.1436096

heterogeneous. This points to the need for frequent inspections to identify and repair leaking or malfunctioning equipment.

There is evidence that these emissions are concentrated, with a small percentage of sources accounting for a large portion of emissions. 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.[20] This is consistent with studies conducted in different basins in the U.S.,[21] and demonstrates the need for frequent leak detection and repair.[22]

These unintended emissions are difficult to predict. Several studies have investigated the relationship between well characteristics/configurations and large unintended emissions, finding they are only weakly related.[23] A 2016 helicopter study of the southwest Pennsylvania region of the Marcellus Basin found that these events occur randomly and are not closely correlated with specific characteristics of well pads (age, production type, well count).[24] 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.[25]

One of the reasons cited for limiting LDAR requirements to three times per year is to account for operational difficulties in the winter months. However, LDAR data from the B.C. Oil and Gas Commission shows that LDAR was conducted at oil and gas facilities in the winter.[26] There do not appear to be persistent access issues in wintertime, both in Canada (Alberta's Directive 055 requires monthly visual inspections of tanks) and in other jurisdictions with challenging winter conditions like Colorado (which requires quarterly or monthly inspections depending on facility size) or Wyoming (which requires quarterly inspections of well sites with a potential to emit 4 TPY of VOC in the Upper Green River Basin).

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[20] Zavala-Araiza "Methane emissions from oil and gas production sites in Alberta, Canada."

[21] Harriss, et al. "Using Multi-Scale Measurements to Improve Methane Emissions Estimates from Oil and Gas Operations in the Barnett Shale, Texas: Campaign Summary," *Environmental Science and Technology* 49 (2015). https://doi.org/10.1021/acs.est.5b02305

[22] D. Cusworth et al. "Intermittency of large emitters in the Permian Basin," *Environmental Science and Technology Letters* 8, no. 7 (2021). https://doi.org/10.1021/acs.estlett.1c00173

[23] D.R. Lyon et al., "Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region," *Environmental Science and Technology*, 49, no. 13 (2015). https://doi.org/10.1021/es506359c

[24] D.R. Lyon et al., "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," *Environmental Science and Technology* 50, no. 9 (2016). https://doi.org/10.1021/acs.est.6b00705

[25] Arvind P Ravikumar et al. "Repeated leak detection and repair surveys reduce methane emissions over scale of years" *Environ. Res. Lett.* **15** 034029 (2020)

[26] B.C. Oil and Gas Commission, "Leak, Detection and Repair Data for Wells and Facilities [BCOGC-87988]." https://www.bcogc.ca/data-reports/data-centre/?category=2772

A recent study in British Columbia found that 23% of methane emissions in the province resulted from unlit flares.[27] This indicates that flares should be inspected frequently for flame-outs and equipped with auto ignitors.

1.2.1 Comprehensive and frequent LDAR

Regular inspections with modern detection instruments — such as optical gas imaging (OGI) cameras — is the best way to minimize emissions from these sources. Recognizing this, many jurisdictions now require frequent LDAR inspections at most or all sites:

- **Alberta (Peace River region):** operators are required to conduct monthly LDAR surveys at high-risk sources which include storage tanks, flare ignitors/pilots, and compressor seals, and must quantify all leaks that are not repaired within 24 hours.[28]
- **Colorado:** requires existing sites to be surveyed at various frequencies, but all new sites are inspected monthly.
- **California**: requires quarterly inspections of all well sites, gathering and boosting compressor stations, and transmission compressor stations.
- **New Mexico:** requires regular inspections for all well sites, including quarterly inspections for all well sites with calculated potential annual emissions of 5 TPY of VOCs or more. Compressor stations with potential VOC emissions of 25 TPY or more must also conduct quarterly inspections.
- **U.S. EPA:** has proposed quarterly inspections for well sites with estimated annual emissions of 3 TPY or more of methane.

Due to the unpredictability and mutable nature of equipment leaks, **we recommend that LDAR inspections should conducted at least quarterly at most facilities, and monthly at larger facilities** (an increase from three times annually in the federal regulation).

1.2.2 Shift towards measurement-based LDAR

We recommend facilitating the implementation of emerging technologies for LDAR, including technologies that would allow inspection of many facilities over a wide area (for example from aircraft) by an independent party. It is essential that any such approach be strictly measurement-based, and sensitive enough to find small emissions sources. Natural Resources Canada's (NRCan) Centre for Excellence could help develop standards for measurement-based LDAR.

The federal government should also consider moving towards an independent, centralized, and national measurement-based LDAR program. This program could be housed in an arm's-length

[27] Tyner, "Where the Methane Is."

[28] *Directive 084.*

organization such as an academic institution 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.

The NRCan Centre for Excellence on methane could be used as a foundation for such a program, if there is a focus on emissions detection and measurement in the oil and gas sector. Such a program, funded by industry, would streamline data-gathering, verification, and compliance, as well as fulfill the Centre's mandate to improve methane detection and elimination.

1.3 No emissions from 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.[29]

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 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.[30] A recent update to this report finds that new technologies have appeared on the market since 2016, while implementation barriers have lowered for some of the more established technologies that were described in the 2016 report. The update finds that "zero-emission controllers are very relevant for reducing emissions from the oil and gas sector."[31]

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, U.S. EPA has proposed

[29] Tyner, "Where the Methane Is."

[30] 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/

[31] Carbon Limits, *Zero Emission Technologies for Pneumatic Controllers in the USA: Updated applicability and cost effectiveness* (2021), ii. https://www.catf.us/resource/zero-emission-technologies-for-pneumatic-controllers-in-the-usa/

standards that would require non-emitting controllers at all new and existing well sites and compressor stations in the U.S.:

- **British Columbia:** requires all new pneumatic controllers and pumps to be zero bleed, and required retrofit of existing controllers at all large compressor stations to eliminate emissions by the beginning of 2022.
- **Colorado:** has prohibited the use of venting gas-driven controllers at new sites since May 2021, and also requires operators to retrofit a portion of their fleet of venting gas-driven controllers to eliminate emissions. Operators were required to convert a certain portion of their facilities or controllers by May of this year, and must complete additional conversion by May 2023.
- **New Mexico:** has very recently promulgated rules which will prohibit the use of venting gas-driven controllers, and will also require operators to phase out existing gas-driven controllers over a period of several years.

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.[32] Technologies like this allow replacement of venting gas-driven controllers at all sites, including small off-grid locations, making it feasible to eliminate the use of wasteful, polluting venting controllers.

We recommend that ECCC require all new and existing pneumatic devices and pumps to be zero-bleed starting in 2025.

1.4 More detailed emissions reporting

To ensure transparency and evaluate compliance, regulations need to be underpinned by a comprehensive reporting framework. Federal regulations do not currently require any reporting of methane emissions, only record keeping.

The U.S. EPA requires comprehensive annual reporting of methane emissions from applicable facilities at a detailed source level in the Greenhouse Gas Reporting Program (GHGRP). Another example is B.C., which requires detailed reporting and quantification of all leaks by source

We recommend that Canada adopt detailed source-level reporting similar to GHGRP, and that the data be made publicly available to give stakeholders confidence that rules are being followed. A further advantage of eliminating some sources of emissions, such as venting or

[32] 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

flaring, is that this will reduce the number of sources that operators would need to report. The following sources should be included in this reporting framework:

- Leaks
- Atmospheric storage tanks (solution/associated gas)
- Pneumatic devices
- Pneumatic pumps
- Reciprocating compressors packing vents
- Centrifugal compressor seal vents
- Casing gas vents (solution/associated gas)
- Well completions and testing
- Equipment/piping blowdowns
- Liquids unloading
- Dehydrator still column vents
- Compressor engine starters
- Surface casing vent/gas migration

We also 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.

2. Reduce oil and gas methane to near-zero levels by 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 Canada 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 set a pathway to near-zero methane emissions in the oil and gas sector by 2030. Doing so is essential to protect our climate and achieving a declining cap in oil and gas emissions.

The 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, Canadian federal policy 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 target for oil and gas sector.

Achieving this may require standards that move beyond the work practice and equipment-based regulatory approach that federal regulations have used to date. It will be valuable for Canada to consider a number of these approaches, such as:

- Overall emissions limits for facilities by facility and production type
- Taxing methane within the framework of Canada'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. The 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 current inventory estimates).
- 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. 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.[33]

While a standardized direct measurement protocol is yet to be widely accepted, there are several leading examples that should be examined:

- **The Oil and Gas Methane Partnership 2.0 Framework** (OGMP 2.0) gives guidelines on moving from estimates using generic emission factors (level III), to specific emission and activity factors (level IV), and finally to including site-level measurement to reconcile estimates (level V). OGMP 2.0 typically allows firms three years from joining the partnership to move to level IV or level V.
- **EU methane regulations**, currently in the draft stage, are slightly more ambitious on timelines. Within one year of implementation, firms are obliged to report site-level estimates using emission factors (aligned with OGMP 2.0 level III). Within two years, firms must submit direct source-level emissions, and within three years must deliver complementary site-level measurements.
- **GTI Veritas** is an initiative launched by the Gas Technology Institute (GTI) which is consulting with a wide range of technical experts with the aim of creating a standard approach for integrating measurements into methane emissions inventories. Veritas

[33] D.T. Shindell, J.S. Fuglestvedt, W.J. Collins, "The social cost of methane: theory and applications" *Faraday Discussions* 200 (2017). https://pubs.rsc.org/en/content/articlelanding/2017/FD/C7FD00009J

has proposed protocols for measurement and data reconciliation along the whole natural gas value chain with the objective of demonstrating emission reductions credibly, consistently, and transparently. This methodology can serve a wide range of needs: certification standards, regulatory compliance, government and company greenhouse gas inventories, and ESG disclosures.

3. Establish a Global Centre of Excellence

The federal government has a mandate to establish a Global Centre of Excellence on methane detection and elimination. It is well established that the knowledge gap lies not in the technology needed to eliminate methane emissions, but in accurate data on the level of emissions, the sources of those emissions, and how they change over time.

The forthcoming Centre of Excellence should focus on obtaining accurate data on sources and behaviour of emissions sources, to inform federal regulations and evaluate progress towards near-elimination of methane emissions from the oil and gas sector. The Centre can also focus on other key issues in addressing methane:

- Develop measurement-based LDAR and reporting standards
- Explore centralized leak detection and measurement programs
- Research solutions to more challenging methane sources, such as oilsands methane

To achieve this, the Centre should be an independent organization which operates at an arm's length from government. As a global centre, it should advance both domestic and international objectives towards methane detection and elimination in the oil and gas sector and beyond.

Conclusion

Thank you for your due consideration of these recommendations. We would welcome the opportunity to better understand the process that federal government will undertake to continue building its climate ambition and leadership and how our organizations can engage in that process.