# Design recommendations for a national oil and gas emissions cap

## Pembina Institute comments and recommendations

Submitted to: Environment and Climate Change Canada | February 5, 2024

Regarding: Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap

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### Recommendation summary

This emissions cap, as proposed, represents a realistic and reasonable pathway to meaningful emissions reductions in the oil and gas sector this decade. The Pembina Institute generally **supports the level and scope of the proposed cap**, despite the cap level being misaligned with the economy-wide target of a 40-45% reduction in emissions by 2030. Nevertheless, this cap is a crucial step forward in bending the curve on emissions in Canada's highest-emitting sector.

Our analysis, based largely on existing industry commitments, demonstrates that the proposed cap level can be achieved without impacting oil and gas production. Here, we provide recommendations on some design elements of the framework, including:

- It is urgent that Canada begins to meaningfully reduce emissions from the oil and gas sector, which existing policy has not yet delivered. As such, **we recommend that the regulatory development timeline for this emissions cap be accelerated where possible.**
- If the world takes greater action on climate, we will see lower emissions in Canada's oil and gas sector as a result of global market-based declines in demand compared to the *Canada Net-zero* scenario, and **the cap should be adjusted accordingly past 2030**.
- A combination of **free allocation and auctioning** should be utilized, with both overall allowances and the number of free allocations declining over time.
- The emissions cap should utilize a **sectoral product benchmark approach**.
- The emissions cap should **undergo regular reviews** in order to a) maintain the marginal price signal in existing carbon pricing systems and b) adjust the level of allocation to align with net-zero by 2050
- **Compliance flexibilities should be phased out over time**, aligning with net-zero by 2050 and taking into account the anticipated decrease in demand.

- We support the proposal that a facility's use of **the decarbonization fund should be limited to 10% of a facility's GHG emissions** for the initial compliance period, but recommend that this is **phased down over time**.
- **ITMOs should not be accepted for compliance flexibility** in the emissions cap.
- **Decarbonization fund revenues should not be allocated to carbon capture projects**. Instead, these revenues could be invested in innovative technology to increase the sector's ability to decarbonize past 2030; to assist smaller facilities with monitoring and reporting requirements; or to support sustainable jobs.

## Context

The Pembina Institute welcomes the opportunity to comment on the proposed regulatory framework for the oil and gas emissions cap. This cap — in conjunction with 2030 methane regulations, currently in draft — will be crucial in ensuring that Canada's oil and gas sector contributes its fair share of greenhouse gas emissions reductions to Canada's economy-wide targets. Oil and gas production remains Canada's largest source of emissions, and unlike some other industrial sectors, its emissions have continued to grow in recent years.

As global and domestic climate action accelerates, demand for oil and gas—including Canada's oil and gas—will decline, and production will decrease as a result of those changes in the global energy marketplace. Importantly, oil and gas production is predicted to decline under various net-zero scenarios from the Canada Energy Regulator, (Figure 1) and this global market-based decline must be taken into account in constructing the cap.

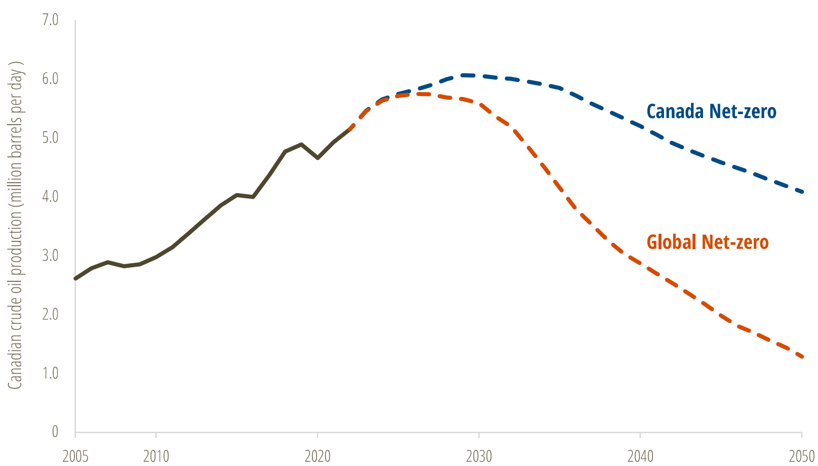


Figure 1. Canadian oil production under the Canada Energy Regulator's net-zero scenarios

Adapted from: Canada Energy Regulator[1]

[1] Canada Energy Regulator, *Canada's Energy Future 2023*, Figure ES.8. https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html

# Discussion and recommendations

## Timeline

The Pembina Institute recognizes that designing a single-sector emissions trading system that complements existing carbon pricing systems and acknowledges provincial jurisdiction over natural resource extraction is challenging, and commends the federal government for the progress made in the release of this regulatory framework.

Despite these challenges, it is urgent that Canada begins to meaningfully reduce emissions from the oil and gas sector, which existing policy has not yet delivered. As such, **we recommend that the regulatory development timeline for this emissions cap be accelerated where possible**. Finalizing the regulation as soon as possible is necessary to ensure that the sector is obligated to begin meaningfully investing in decarbonization.

## Cap level and production trajectory

The cap, with a total quantity of allowances in 2030 of between 106 and 112 Mt $CO_2e$ (35% to 38% below 2019 emission levels) and 25 Mt $CO_2e$ of compliance flexibilities resulting in a legal upper bound of 131 and 137 Mt $CO_2e$ (20% to 23% below 2019 emission levels), is well below the economy-wide target of a 40-45% reduction in emissions by 2030. Given the many options for decarbonization across the sector, **we support the proposed level of the cap for 2030.**

### Net-zero in Canada: The proposed cap is responsible and realistic

The Pembina Institute's analysis shows that technically achievable emission reductions will be sufficient to meet the proposed cap, assuming a production trajectory aligned with the Canada Energy Regulator's *Canada Net-zero* scenario (CNZ). The CNZ scenario includes all the climate commitments and longer-term targets made by governments around the world , including Canada's net-zero by 2050 target, and shows an increase in production by 2030 before global demand goes into long-term decline (Figure 1).

We find that the proposed cap can be technically achieved by 2030 without impacting oil and gas production. Our analysis is based largely on existing industry commitments (like the Pathways Alliance plan to reduce emissions by 22 Mtpa by 2030) and federal targets to reduce oil and gas methane.

The bulk of reductions (Figure 2) come from methane reductions of 75% below 2012 levels already stated in the draft methane regulations; carbon capture and storage (CCS) supported by significant subsidies in the form of tax credits at both the federal and provincial levels in Alberta; and partial electrification of upstream processes. These actions would already bring emissions below the legal upper limit of 137 Mt $CO_2e$, and only an additional 15 Mt of compliance measures would be required to reach the allowance target of 112 Mt $CO_2$e. This is notably less than the 25 Mt $CO_2$e proposed in the emissions cap framework, and gives substantial flexibility for the industry to meet this cap.

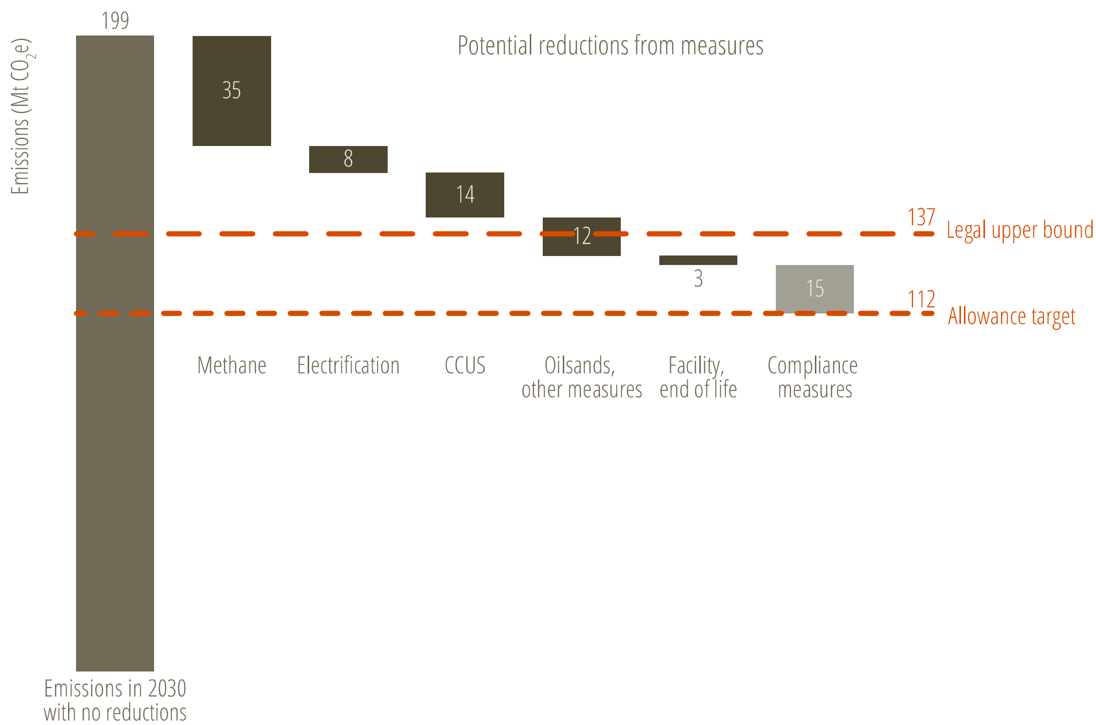


Figure 2. Measures that could reduce GHG emissions to meet the proposed oil and gas emissions cap framework[2]

Production is aligned with the CER's Canada Net-zero scenario: global market-driven demand for oil and gas results in increased production until 2030 and emissions increase from 171 Mt in 2019 to 199 Mt in 2030. Long-term decline in demand begins after 2030.

## Net-zero worldwide: Even faster declines in production

The proposed cap is based on a production trajectory similar to the CNZ; however, if global oil and gas production is closer to the trajectory of the Canada Energy Regulator's *Global Net-zero* (GNZ) scenario (Figure 1), the emissions cap is achievable without the use of compliance measures with technically achievable reductions.

Emissions from the oil and gas sector in our 2030 scenario based on GNZ (Figure 3 below) were calculated with the Canada Energy Regulator's production forecasts and associated emissions intensities from the 2021 National Inventory Report, which represent the emissions intensity in the year 2019 (see Appendix A).

[2] See Appendix A for a discussion of the assumptions underlying the analysis in Figures 2 and 3,

While the GNZ still exhibits a small increase in production and an overall increase in emissions of 5 Mt by 2030, if the world takes greater action on climate, we will see lower emissions (up to 23 Mt $CO_2$e by 2030) in Canada's oil and gas sector as a result of global market-based declines in demand compared to the CNZ scenario. As production continues to decline past 2030, we will see naturally lower emissions and **the cap should be adjusted accordingly**, as we discuss below.

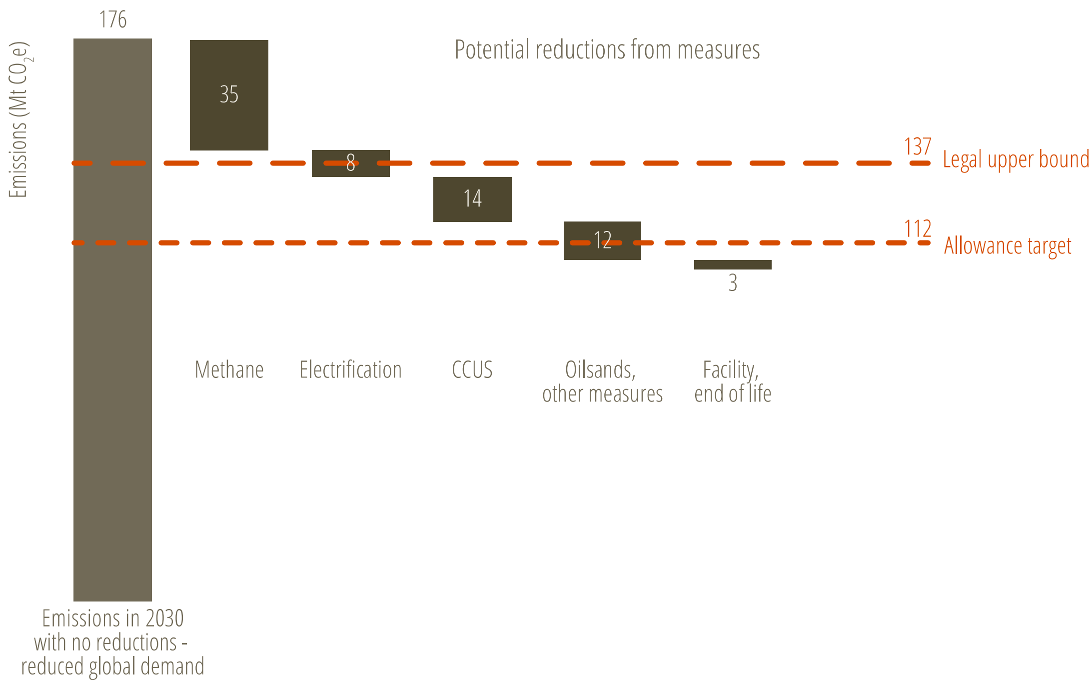


Figure 3. Effect of reduced global demand on reaching oil and gas emissions cap

Production is aligned with the CER's Global Net-zero scenario: stronger action on climate change means global demand for oil and gas declines sooner and faster. The cap is technically feasible without the need for compliance measures, and emissions could fall below the intended allowance target of 112 Mt.

# Framework questions

*How should allowances be allocated? What should be taken into account? How should changes in production and new projects be considered?*

## Allowance allocation

Most cap-and-trade systems, including the European Union, Quebec and California, distribute emissions allowances through a combination of free allocations and auctioning.

Over EU ETS Phase 4 (2021-2030), about 57% of general allowances are to be auctioned, encompassing all sectors including emissions-intensive and trade-exposed (EITE) sectors.[3] Free allocations have been extended through Phase 4; certain EITE sectors (which include crude oil extraction and refined petroleum products, but not natural gas extraction) will receive 100% of their allocation for free, with a review at five years.[4] For less-exposed sectors, free allocation aims to be phased out after 2026 from a maximum of 30% free allocation to 0% at the end of Phase 4 in 2030 (22.5% in 2027; 15% in 2028; 7.5% in 2029).

In the California ETS, allowances are distributed either via direct (free) allocation to regulated entities, or sale at auction to all market participants. In 2021, about 62% of total California-issued vintage 2021 allowances were made available through auction.[5] In addition, the total allowance budget is decreasing (by 3.5% in 2020).[6]

Both the European Union and the California-Quebec market have instituted market stability provisions to manage an over- or under-supply of credits: the Market Stability Reserve in the EU; the Allowance Price Containment Reserve in California; and an allowance reserve in Quebec, which is filled with a set portion of the annual cap (4% in 2021). **We recommend that a market stability provision should be included from the outset, in order to maintain allowance certainty.**

**The Pembina Institute recommends that a combination of free allocation and auctioning be utilized, with both overall allowances and the number of free allocations declining over time** to align the sector with net-zero by 2050. If, as proposed in the framework, 100% of allowances are distributed through free allocation when the system is initially implemented, then a gradual transition to auctioning should be considered after the first compliance period.

### Benchmark-setting

**We recommend that the emissions cap utilize a sectoral product benchmark approach, similar to Alberta's CCIR, and not a jurisdictional approach**. Such an approach would hold all facilities within the oil and gas sector to the same emissions intensity limit, based on the

[3] European Commission, "EU Emissions Trading System: Auctioning." https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/auctioning_en

[4] European Commission, "EU Emissions Trading System: Allocation to industrial installations." https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/free-allocation/allocation-industrial-installations_en

[5] International Carbon Action Partnership, "California Cap-and-Trade Program." https://icapcarbonaction.com/en/ets/usa-california-cap-and-trade-program

[6] California Air Resources Board, "Allowance Allocation." https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/allowance-allocation

product and technology (e.g. barrel of bitumen produced via in-situ, barrel of bitumen produced via mining, amount of gas processed, etc.). This approach ensures that producers within each sector are treated equally, first-movers are rewarded, and all facilities have the same financial incentive to reduce emissions.

### Changes in production and new entrants

The EU ETS includes a New Entrant's Reserve, which reserves 5% of allowances "to assist new installations or to cover installations whose capacity significantly increased since their free allocation had been determined."[7] We recommend that the emissions cap similarly set aside a small portion of free allocations to account for significant changes in production at the facility level, or for new facilities.

The proposed regulatory framework states that "free allocation would be adjusted up or down on a facility basis should the facility's production rise or fall by more than a predetermined percentage from the baseline production level." The EU ETS also provides some guidance with regards to production variability, setting the threshold for adjustment of free allocation at 15% increasing or decreasing production. **We recommend that the emissions cap adopt similar guidelines to the EU ETS for both new entrants and production variability.**

### *What process should be established to review the emissions cap trajectory for the post-2030 period?*

Regular review of the emissions cap is absolutely essential to assess the performance of the policy and the state of the allowance market; to ensure that the marginal price signal in existing carbon pricing systems is maintained; and to align the sector with net-zero by 2050. A single-sector market like this emissions cap does increase the risk of volatility in the carbon market. Global oil prices or a potential influx or absence of emissions reductions risks over- or under-supplying the market, leading to a much higher or lower price of carbon than in other sectors.

The emissions cap should undergo regular reviews after 2030, similar to federal and provincial pricing systems. **We recommend that regular reviews are conducted in the year before a new compliance period starts.** This will allow adjustment of allocations and compliance flexibilities in the next compliance period and allow for the level of the cap to reflect investments in decarbonization and impacts on provincial pricing systems. For instance, as projects with longer lead times like CCS or large electrification projects come closer to final investment decisions, elements of the cap (amount of compliance flexibility, amount of free

[7] International Carbon Action Partnership, "EU Emissions Trading System." https://icapcarbonaction.com/en/ets/eu-emissions-trading-system-eu-ets

allowances) could be adjusted in the next compliance period to account for expected emissions reductions from those projects. Additionally, regular and frequent reviews would also allow for a transition towards auctioning to begin sooner.

In addition to regular reviews when setting the cap for the next compliance period, we recommend that additional reviews of the cap are triggered if the marginal price signal in existing carbon pricing systems is weakened. The marginal price signal in existing industrial carbon pricing systems must be maintained, especially since those systems are meant to incentivize decarbonization across sectors.

### *If, when and to what extent some compliance flexibilities should be phased down or phased out.*

#### Compliance flexibility over time

One purpose of the proposed compliance flexibility is to allow the sector to adapt to changes in global oil and gas demand, aiming to cover additional production up to 2030 based on the CER's Canada Net-Zero (CNZ) scenario. According to the CNZ scenario, oil and gas production is expected to begin long-term decline around 2030. While scenario forecasting is imperfect, it provides a starting point for revising the legal upper limit after 2030. **We recommend that compliance flexibilities should be phased out over time, aligning with net-zero by 2050 and taking into account the anticipated decrease in demand.**

**We recommend that reliance on the decarbonization fund should be phased out first.** This mechanism does not result in real emissions reductions (unlike, for instance, on-site decarbonization projects or high-quality offsets that reduce or remove emissions elsewhere). Given the price signals in existing carbon pricing systems, the ability to purchase compliance units should be minimized under the oil and gas emissions cap. **We support the proposal that a facility's use of the decarbonization fund should be limited to 10% of a facility's GHG emissions for the initial compliance period, but recommend that this be phased down over time.**

#### Multi-year compliance periods

Retaining multi-year compliance periods is essential to encourage investment in long-lead projects in decarbonization such as CCS, and most cap-and-trade systems use multi-year compliance periods to provide some flexibility to industry. This flexibility ensures the deployment of the most cost-effective mitigation measures, irrespective of the facility. Some methods of oil and gas production may have limited opportunities to reduce emissions and will rely on credit trading until the market cost becomes prohibitively high. **We support the**

**proposal in the framework that compliance periods be three years, although we recommend that the length of compliance periods be regularly reviewed.**

**Furthermore, we support the proposal that banking of purchased credits should be limited to two compliance period (six years at most**). Banking of credits — allowing companies to hold credits from periods when mitigation costs were cheaper and use them in future periods when mitigation costs are more expensive — will allow flexibility to address market fluctuations that may include production variability or technological advancements.

### High-quality offsets

The oil and gas emissions cap should emphasize higher-quality emissions offsets over time along with the phase-out of lower quality offsets. Developing high-quality offsets, including CDR offset protocols and projects, should be a focus for Canada. We recommend taking into account the Oxford Principles for Net Zero Aligned Carbon Offsetting:[8]

- Principle 1: Cut emissions, use high-quality offsets, and regularly revise offsetting strategy as best practice evolves
- Principle 2: Shift to carbon removal offsetting
- Principle 3: Shift to long-lived storage
- Principle 4: Support the development of net-zero-aligned offsetting

**We recommend that only offsets purchased through the Canada GHG Offset System or recognized provincial protocols should be accepted for compliance purposes.**

## *How should the proposed approach to indirect GHG emissions be implemented?*

### Scope

We support the proposal that facilities are required to quantify the import/export of energy and electricity resulting in indirect GHG emissions to produce oil and gas. Accurately accounting for transfers of thermal energy, electricity, $CO_2$, and hydrogen will be critical to achieving real sectoral emissions reduction. We support the proposal that regulated facilities under the cap should be required to account for energy consumed in their operations, including behind-the-fence electricity generation and the import of energy from other facilities, that will increase total emissions.

[8] University of Oxford, *The Oxford Principles for Net Zero Aligned Carbon Offsetting* (2020), 1. https://www.smithschool.ox.ac.uk/sites/default/files/2022-01/Oxford-Offsetting-Principles-2020.pdf

## Electricity

We recommend that the treatment of indirect electricity emissions under the emissions cap be aligned with the forthcoming Clean Electricity Regulations, as well as with provincial carbon pricing systems. As we note in our feedback to those draft regulations, electricity emissions should be fully priced by 2035; electricity generation should not be considered "emissions intensive", as low or non-emitting generation options exist and are now cost-competitive with (if not cheaper than) fossil alternatives. The electricity sector should also be considered in isolation in future industrial carbon pricing equivalency assessments. Onsite, or behind-the-fence generation, should be covered under the oil and gas cap, but emissions associated with exported power should not be in the scope of the cap. So as not to penalize a site with onsite power generation versus a site without, allocations for a facility should be adjusted based on emissions associated with imported power, for instance by using average grid intensity.

## $CO_2$

Allowance allocations under the oil and gas emissions cap should be based on the volume of permanent $CO_2$ storage or utilization and not on the volume of $CO_2$ exported/imported, to ensure real emissions reduction. Permanence requirements and quantification protocols for $CO_2$ must be clear prior to the oil and gas emissions cap coming into force and should align with provincial regulations.

Regulated capture facilities should be eligible to receive a form of credit or allowance allocation to reduce their total regulated emissions at the capture site once the exported carbon is permanently sequestered or utilized, regardless if the storage facility is regulated. Conversely, a regulated sequestration facility should not be allowed to use imported $CO_2$ from unregulated facilities towards the reduction of their total regulated emissions.

For a sector-specific policy such as this, several carbon capture scenarios may arise including instances where captured $CO_2$ is geologically stored by facilities not covered by the oil and gas emissions cap, or where $CO_2$ is stored by a facility that is regulated but the capture facility is not covered. With the emergence of carbon sequestration hubs in Alberta, this scenario will be increasingly prevalent and requires consideration to mitigate double-counting.

**We support the proposal that emissions reductions from carbon capture, utilization, and storage could count towards both a provincial system and the emissions cap**; however, it is essential that a facility is not allowed to double-count emissions reductions and only gets credit for a single tonne of emissions reductions in both systems.

### Alberta's CCUS offsets

In the Alberta TIER system, $CO_2$ remains a total regulated emission with the facility that generated it. The system allows regulated facilities that capture and store $CO_2$ onsite to receive a direct benefit as stored $CO_2$ is not included in total regulated emissions. If a regulated facility exports $CO_2$ to another regulated facility for storage, exported $CO_2$ is included in total regulated emissions to account for potential subsequent release and the receiving or importing facility subtracts the imported and stored $CO_2$ from their total regulated emissions.

For instances where a regulated facility exports $CO_2$ to be sequestered at an offset project, the capture facility reports exported $CO_2$ which is still included in total regulated emissions to account for potential subsequent release. The imported $CO_2$ from a regulated facility is eligible for emissions offsets using the CCS or EOR quantification protocols and the offset facility becomes the owner of the verified emissions offset.

Under TIER, emissions offsets can be converted to sequestration credits if requested by the offset facility where they are eligible for stacking with the federal Clean Fuels Regulation (CFR) and have a six-year expiry. Sequestration credits can be further converted to capture recognition tonnes by a facility that initiated the capture and holds the sequestration credit. The capture recognition tonnes are deducted from a facility's total regulated emissions and have no credit use limit under TIER.

**We recommend that with regards to the TIER CCUS process, the federal cap recognizes captured $CO_2$ that is stored onsite and carbon recognition tonnes as a reduction of the facility's total recommended emissions, to align compliance under TIER and the federal emissions cap.**

### *What measurement protocols or quantification methods most accurately estimate methane emissions at the facility level?*

There is currently no one-size-fits-all solution for accurately measuring facility-level methane. Each approach comes with trade-offs in cost, speed, sensitivity, localization capacity, and susceptibility to weather conditions. Active sensing aircraft technologies such as Bridger are an excellent choice to generate accurate facility-level data relatively quickly. However, ground-level approaches, drones, and continuous monitoring technologies also have advantages. **We recommend that frequent and comprehensive measurement be done using one or more of the established technologies and that regulations allow a variety of technological pathways to compliance**. We provide a overview of methane measurement technologies in Appendix B.

International best practices for methane reporting, such as the EU's provisional agreement on energy sector methane and the U.S. EPA's Greenhouse Gas Reporting Program, are moving toward greater transparency for company and facility-level methane emissions. Transparent measurement data is key to holding emitters accountable and keeping the public informed. In addition to requiring mandatory facility-level measurement, Canada should make the results of LDAR and measurement surveys publicly accessible.

Given that 2030 methane regulations are also in development, with provincial equivalency negotiations with British Columbia, Alberta, and Saskatchewan to follow, **the methane quantification methods accepted for the emissions cap should align with those final methane regulations.**

### Centre of Excellence for methane

It is imperative that realistic and accurate baseline methane measurements are collected. With recent studies indicating that methane emissions may be up to 50% higher than previously reported, a better understanding of the industry's baseline will be crucial to ensure the accuracy of methane reductions that are occurring.[9]

The Centre of Excellence for methane, with $30 million in funding announced in conjunction with the draft methane regulations, could be a key forum to improve our understanding and reporting of methane emissions, with a focus on collaborative initiatives to support data and measurement.

## *What administrative approaches can be used to define and regulate facilities with GHG emissions below 10 kt $CO_2e$ per year?*

Facilities below the 10 kt $CO_2e$ per year threshold that are owned by the same emitter should be allowed to aggregate to reduce the administrative burden and cost of compliance. This will also avoid large volumes of reports from small facilities that individually reveal little new information about the broader emissions trajectory, compared with aggregated reports. We recommend that facilities be able to aggregate within the same product benchmark with distinct emissions profiles and asset characteristics (e.g. light and medium oil, conventional natural gas, tight gas, etc.).

That said, reporting and verification requirements for small oil and gas facilities and aggregates need to improve from the current state (where there are few checks and little incentive for facilities to improve their reporting). This will be especially important when methane is added to the cap. Given the large number of facilities in this sector, verification requirements should be fit-for-purpose, and will likely need a phased approach. Critically, verification from relevant

[9] Bradley Conrad, David Tyner, Hugh Li, Donglai Xie, and Matthew Johnson, "A measurement-based upstream oil and gas methane inventory for Alberta, Canada reveals higher emissions and different sources than official estimates," *Communications Earth & Environment* 4, no. 416 (2023), 3. https://doi.org/10.1038/s43247-023-01081-0

government authorities needs to happen frequently and systematically, and with appropriate human and financial resources.

### *How should the proceeds from the decarbonization funding program be distributed? How should contributions be used to support decarbonization of the oil and gas sector?*

We recommend that a portion of the revenue raised by the decarbonization fund be allocated to R&D for solutions that would increase the ability of the sector to reduce emissions past 2030. However, we recommend that these funds **not be allocated to carbon capture projects.** Between the separate Investment Tax Credits announced by the federal government and Alberta's provincial government, with most of the support available through the federal credit, **no further public support is needed, particularly for oilsands projects.**

Our cash-flow analysis of oilsands CCS indicates that these projects are financially feasible under a range of potential costs and incentives, assuming a consistent carbon price that reaches $170 per tonne in 2030.[10] In the oilsands context, CCS is not only an investment in competitiveness and regulatory compliance, but it can also offer positive returns for what is the cost of doing business in the low-carbon economy. Rather than committing additional public funds to these projects, the focus should be on improving carbon price certainty.

Additionally, a portion of the funds could be directed toward assisting smaller facilities within the oil and gas sector with compliance and monitoring measures. This targeted support will help ensure that smaller facilities can be regulated effectively, fostering a more comprehensive approach to decarbonization across the industry and ensuring that the one-third of emissions coming from small facilities are addressed under the emissions cap.

Finally, a portion of the fund could be earmarked for investing in sustainable jobs, aligning with the principles outlined in the Pembina Institute's *Sustainable Jobs Blueprint*.[11] As technology and policy changes accelerate around the world, Canada must be ready and able to take advantage of the opportunities that will emerge. Investing in readying the workforce for technological change and emerging technologies, as well as promoting economic diversity through a range of policy measures, ensures that Canada can be a destination for investments and good jobs.

[10] Scott MacDougall, Jonathan Arnold, Janetta McKenzie, *Cash flow modeling shows carbon capture and storage can help meet climate goals* (Pembina Institute, 2023). https://www.pembina.org/pub/cash-flow-modeling-shows-carbon-capture-and-storage-can-help-meet-climate-goals

[11] Megan Gordon, Alex Callahan, *A Sustainable Jobs Blueprint: Part II: Putting workers and communities at the centre of Canada's net-zero energy economy* (Pembina Institute and Canadian Labour Congress, 2023). https://www.pembina.org/pub/sustainable-jobs-blueprint-part-ii

### *What are the advantages and disadvantages of a federal offsets fund? How should a federal offsets fund operate?*

As stated in the proposed regulatory framework, a federal offsets fund could provide price certainty for federal offsets to the oil and gas sector. However, this approach would not provide certainty for other sectors that also utilize offsets as compliance under other systems like the OBPS, or for provincial offsets. If such offset price certainty is pursued, then the oil and gas cap is not the most appropriate forum given its single-sector focus.

### *What role should ITMOs play in compliance flexibility?*

**We recommend that ITMOs are not accepted for compliance flexibility in the emissions cap.** ITMOs under Article 6 of the Paris Agreement are still in the early stages of development, with persistent issues around emissions accounting to ensure that emissions reductions are additional and verifiable.

In particular, Canada's LNG exports should not be eligible for ITMOs. Article 6 is meant to allow countries that are on track to meet or exceed their NDC to sell credits to countries that are behind their goals. None of the countries that have been identified as significant potential importers of Canadian LNG (China, Japan, South Korea) are on track to meet their NDCs under existing policies, and so there is little incentive to enter into an ITMO agreement with Canada. Due to persistently underestimated methane emissions (as we discuss above), the case for switching to LNG on an emissions basis is limited.

# Appendix A: Calculation of potential GHG reductions by mitigation measure

The assumptions in our analysis of the emissions reduction pathways in Figures 2 and 3 are described in detail below.

**Additional production** is accounted for in the emissions cap framework, increasing total emissions from the oil and gas sector by 28 Mt $CO_2e$ in 2030. The *Global Net-zero* scenario is calculated based on the Canada Energy Regulator production forecasts and associated emissions intensities from the 2021 National Inventory Report, representing the emissions intensity in the year 2019 and resulting in an emissions increase of only 5 Mt $CO_2e$ in the year 2030.[12, 13]

**Methane**: Methane emissions from the oil and gas sector could be reduced by 35 Mt assuming draft methane regulations are met in 2030, effectively reducing methane emissions from 59 Mt in 2012 to 15 Mt in 2030. Reductions of 35 Mt include both fugitive sources and stationary combustion sources. If only fugitive sources are considered, a 75% reduction from 2012 levels would equate to 33 Mt. Methane emissions have already seen reductions to 49 Mt and 39 Mt in 2019 and 2021 respectively.[15] Methane emissions continue to represent the largest opportunity for emissions reduction from the oil and gas sector.

**Electrification**: Electrifying engines and compressors used in the production, processing, and transport of natural gas and conventional oil could reduce combustion emissions by 8 Mt. We believe this is a conservative estimate, as we assume that facilities less than 1 km from existing transmission lines in Alberta and Saskatchewan (13%) can be electrified, based on Pembina's research. If we consider facilities in Alberta and Saskatchewan that lie less than 7 km from existing transmission (48%), electrification could potentially reduce emissions by 15 Mt. British Columbia has indicated a strong desire to increase industrial electrification including at oil and gas facilities. We believe facilities producing from the Montney, accounting for 89.2% of gas production in B.C., have the highest probability of electrification due to location. We assume two-thirds of engines and compressors can be electrified, totalling 60% of engines and

[12] Canada Energy Regulator, *Canada's Energy Future Data Appendices* (2023). https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

[13] Environment and Climate Change Canada, *National Inventory Report 1990–2019: Greenhouse Gas Sources And Sinks In Canada* (2021). https://publications.gc.ca/site/eng/9.506002/publication.html

compressors in B,C.[14] Emissions reductions through electrification were calculated as outlined below.

First, emissions from combustion sources and engines in each province (Table 1) were estimated using the provincial distributions from the 2023 National Inventory Report (which was based on 2021 data), the portion of emissions from combustion sources in B.C. based on the 2021 B.C. provincial inventory, and distribution of oil production between Saskatchewan and Alberta using 2021 data from the Canadian Energy Regulator (CER).[15, 16, 17]

Table 1. GHG emissions from combustion sources in oil and gas sub-sectors across Canada

| Province and sub-sector | Combustion (Mt $CO_2e$) | Engines (Mt $CO_2e$) |
|---|---|---|
| B.C. | 8.8 | 7.6 |
| Natural gas production and processing | 7.6 | 6.4 |
| Oil, natural gas, and $CO_2$ transmission | 1.2 | 1.2 |
| Saskatchewan | 5.0 | 3.2 |
| Natural gas production and processing | 0.5 | 0.4 |
| Conventional light oil production | 0.4 | 0.3 |
| Conventional heavy oil production | 2.6 | 1.0 |
| Oil, natural gas, and $CO_2$ transmission | 1.5 | 1.5 |
| Alberta | 27.9 | 21.8 |
| Natural gas production and processing | 20.1 | 14.5 |
| Conventional light oil production | 2.8 | 2.6 |
| Conventional heavy oil production | 0.6 | 0.3 |
| Oil, natural gas, and $CO_2$ transmission | 4.4 | 4.4 |
| Ontario and Manitoba | 1.4 | 1.4 |
| Oil, natural gas, and $CO_2$ transmission | 1.4 | 1.4 |

[14] B.C. Energy Regulator, *British Columbia's 2022 Oil and Gas Reserves and Production Report*, (2023), 13. https://www.bc-er.ca/files/reports/Reserves-and-Production-Reports/2022-Oil-and-Gas-Reserves-and-Production-Report_Aug-28.pdf

[15] *National Inventory Report 1990–2021.*

[16] Government of B.C., "Industrial facility greenhouse gas emissions" (2023). https://www2.gov.bc.ca/gov/content/environment/climate-change/data/provincial-inventory

[17] *Canada's Energy Future Data Appendices* (2023).

The proportion of combustion emissions attributed to engines (as opposed to boilers and heaters) was estimated using data from the 2014 Clearstone Engineering Ltd inventory of emissions from the upstream oil and gas industry (Table 2).[18]

Table 2. Distribution of fuel burned by equipment type for oil and gas sub-sectors

| Facility type | Engines | Boilers/ heaters |
|---|---|---|
| Light/medium crude oil production | 91% | 9% |
| Heavy crude oil cold production | 50% | 50% |
| Heavy crude oil thermal production | 1% | 99% |
| Natural gas production and processing | 72% | 28% |
| Natural gas production and processing, B.C. | 84% | 16% |

Then, to estimate GHG reductions from converting these natural gas-fired combustion engines to electric-driven (Table 3), the following factors were assumed:

- Combustion engine thermal efficiency: 35%[19]
- Sites with access to the electricity grid: 60% of sites in B.C., 13% in Saskatchewan, 13% in Alberta, and 100% in Manitoba and Ontario.
- Electrical grid emission factor, 2030 (in t $CO_2e$/GWh)[20]: Alberta: 120, Saskatchewan: 84, Ontario: 26, Manitoba: 1

Table 3. GHG emissions and reduction potential from electrifying engines in oil and gas sector in (Mt $CO_2e$)

| Province | Combustion GHGs | Engine GHGs | GHGs from engines with grid access | GHG reduction from electrification |
|---|---|---|---|---|
| B.C. | 8.8 | 7.6 | 4.5 | 4.5 |
| Saskatchewan | 5.0 | 3.2 | 0.4 | 0.3 |
| Alberta | 28.0 | 21.8 | 2.8 | 2.1 |
| Ontario and Manitoba | 1.4 | 1.4 | 1.4 | 1.3 |
| Total | 43.2 | 34.0 | 9.2 | 8.3 |

**Carbon capture and storage** (CCS): The Pathways Alliance's proposed oilsands CCS network is expected to reduce emissions between 10 and 12 Mt $CO_2e$; our analysis assumes 10 Mt will be

[18] Clearstone Engineering Ltd., *UOG Emissions Inventory Methodology Manual*, Volume (2014), 36.

[19] *UOG Emissions Inventory Methodology Manual*, Volume 3, 38.

[20] Canada Energy Regulator, *Canada's Energy Future (2021)*, net-zero base scenario. https://www.cerrec.gc.ca/en/data-analysis/canada-energy-future/2021/index.html

captured in 2030. We find an additional 4 Mt $CO_2e$ of reductions by assuming 90% of $CO_2$ vented from gas processing plants is captured with CCS.

**Oilsands, other measures** accounts for additional actions announced in the Pathways Alliance Net-zero Initiative[21] amounting to an additional 12 Mt of reductions per year through process improvements, electrification and fuel substitution, energy efficiency, and other levers.

**Facility, end of life** accounts for the expected end-of-life for the Suncor base mine in Alberta in 2030.[22]

**Compliance measures** totaling 15 Mt make up the difference from real sectoral emissions reductions and the legal upper bound by 2030. We believe there is considerable flexibility in reduction pathways that won't require the entirety of the proposed 25 Mt of compliance measures set out in the framework.

[21] Pathways Alliance, "Net-zero Initiative." https://pathwaysalliance.ca/net-zero-initiative/planned-phases/#phase-one

[22] Suncor Energy Inc., *Base Mine Extension, Detailed Project Description Summary* (2020), 23. https://iaacaeic.gc.ca/050/documents/p80521/135634E.pdf

# Appendix B: Methane measurement technologies

| Technology class | Description |
|---|---|
| Handheld | Instruments such as optical gas imaging (OGI) cameras and point analyzers ("Method 21") deployed by individuals on the ground, providing detailed, close-range component-level data. |
| Vehicle | Mobile ground labs equipped with sensors sample methane concentration while driving, providing detailed site-level data. |
| Drone | Drones allow operators to sample methane concentrations from the ground, while accessing hard-to-reach areas, achieving better quantification of emissions from elevated sources. |
| Aircraft | A variety of sensing technologies can be mounted on aircraft, enabling fast and comprehensive site- and region-level surveys. |
| Satellite | Satellites such as TROPOMI, MethaneSAT, and GHGSat determine methane concentrations from space using sensors that detect reflected sunlight, enabling extensive international monitoring for large emitter events. |
| Continuous | Sensors permanently situated at facilities collect data continuously, aiding the detection of intermittent and unpredictable leaks. |