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Options to cap and cut oil and gas sector greenhouse gas emissions

Pembina Institute comments and recommendations

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Regarding: Options to Cap and Cut Oil and Gas Sector Greenhouse Gas Emissions to Achieve 2030 Goals and Net-Zero by 2050

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Recommendation Summary

Prior to investing more time in detailed regulatory design, Environment and Climate Change Canada should finalize and announce a clear emissions cap target for 2026 and 2030. This announcement should be made before COP27 (due to be held in November 2022). At a minimum, the cap for oil and gas sector emissions should be set at a 45% reduction from 2005 levels by 2030, with clear implementation timelines. Providing this level of certainty on the trajectory and ambition of the cap is critical to incentivize urgent investments in decarbonization. Recent opinion polling illustrates that most Canadians agree that it is time for a cap on emissions from oil and gas production, to ensure that this sector does its fair share in achieving Canada's climate targets.

Both cap Options 1 and 2 are complex, and require careful design and implementation to ensure appropriate emissions reductions, while preparing Canadian industry for a net-zero global economy. Both Options could be workable from the perspective of the following principles considered in this feedback:

Be certain: Provide policy certainty early through all possible mechanisms, such as setting interim targets, improving the stringency of the OBPS, creating new policies regarding carbon contracts for difference and carbon border adjustment mechanisms.

Be ambitious: Aim for a reduction in oil and gas emissions of 45% below 2005 levels by 2030, and institute a cap trajectory that incentivizes early action towards that goal. The 2030 cap level should be announced now, before further regulatory design takes place, similar to how the Government of Alberta clearly signaled an oilsands emissions cap limit of 100 Mt in the Oilsands Emissions Limit Act (2016) prior to determining the exact mechanism to achieve it.

Be timely: Be implemented as early as possible, targeting 2024 coming into force.

Be efficient: Minimize additional administrative burdens and unintended impacts and be implemented in the most cost-effective manner to achieve the cap trajectory.

Be flexible: Provide flexibility within the oil and gas sector, while excluding intra-sector trading.

Limit additional government support: No additional decarbonization subsidies should be considered after the upcoming CCUS Investment Tax Credit and credits from the OBPS (or provincial equivalents) and Clean Fuel Regulations.

Allocate revenue to climate priorities: Revenues generated should be allocated to workers and communities affected by the energy transition, addressing orphan and abandoned well liabilities, driving significant emissions reductions, and emissions measurement improvements.

Considering these principles, together with the urgency of reducing Canada's rising oil and gas sector emissions, Option 1 (cap-and-trade) is preferred. It likely offers the earliest implementation date (in 2024 or early 2025) and could be designed to work with existing measures to further incentivize the oil and gas sector to do its fair share to meet Canada's 2030 emission reduction targets.

If the Government of Canada does not believe Option 1 can implemented in these stated timelines, we propose a third option — a system of facility-level emissions limits similar to the federal coal-fired electricity facility limits. This interim option should be rapidly implemented to drive timely emission reductions at oil and gas facilities. Option 1 could still be developed in parallel and implemented when ready. At that time, the facility limits could be rescinded, if found to be redundant with cap-and-trade.

Context

The Pembina Institute welcomes the opportunity to provide input on design of the oil and gas emissions cap.

This cap 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 (of a 45% reduction below 2005 levels by 2030, and net-zero by 2050). 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 — by 19% between 2005 and 2019. To do its fair share, Canada's oil and gas sector must also reduce its emissions by 45% from 2005 levels by 2030.

Environment and Climate Change Canada has outlined two distinct options to regulate and enforce a cap on oil and gas sector emissions:[1]

> Option 1: A new cap-and-trade system under the Canadian Environmental Protection Act, 1999 (CEPA)
>
> Option 2: Modification of existing carbon pollution pricing systems under the Greenhouse Gas Pollution Pricing Act (GGPPA)

Discussion and recommendations

At present, Canada's economy-wide carbon pricing system incentivizes the most cost-effective greenhouse gas emissions reductions, regardless of sector. However, the oil and gas sector is Canada's highest-emitting, and unlike most other parts of the economy, emissions have continued to grow. Additionally, the sector has emissions reduction options available that have not yet been widely deployed, including energy efficiency measures, electrification, use of solvents, carbon capture and storage, and addressing methane emissions. For those reasons, a sector-specific policy is now necessary to incentivize action. Recent polling also demonstrates that the majority of Canadians agree that it is time for a cap so that this sector contributes its fair share of emissions reductions.[2]

Before proceeding further on detailed regulatory design, the federal government should clearly announce the cap level for 2030. This should be aligned with Canada's international target of 45% below 2005 levels. Providing this certainty on the trajectory and ambition of the cap is critical to incentivizing investments in decarbonization, as has been demonstrated with previous policy examples, including methane regulations, Alberta's cap on oilsands emissions, and the coal phase-out — all of which clearly announced a target before proceeding to design policy to achieve that target. We urge the federal government to announce cap levels for 2026, 2030 and 2050 at a minimum as soon as possible, and prior to further regulatory design.

The Pembina Institute supports both cap options in principle. If designed well and implemented quickly to achieve a 45% reduction in sector emissions, either could align with

[1] Environment and Climate Change Canada, *Options to cap and cut oil and gas sector greenhouse gas emissions to achieve 2030 goals and net-zero by 2050.* https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap/options-discussion-paper.html

[2] Climate Action Network Canada, *New poll finds 7 in 10 Canadians want oil and gas emissions cap to ensure industry takes on its fair share of climate action*, September 22, 2022. https://climateactionnetwork.ca/new-poll-finds-7-in-10-canadians-want-oil-and-gas-emissions-cap-to-ensure-industry-takes-on-its-fair-share-of-climate-action/

our cap principles stated above. In any case, it is crucial that the government now moves swiftly to select and implement the cap.

Based on this need for urgent implementation, the cap-and-trade option, which could likely be implemented in 2024 or 2025, is preferred over Option 2, which would only come into force as early as 2027 following the next pricing benchmark equivalency review. The benefits of timely implementation are twofold: first, the sooner the cap is implemented, the sooner it will start to bend the curve for the sector's emissions. Second, rapid implementation will provide greater policy certainty for companies, which they have expressed is required for them to begin investing current windfall profits in decarbonization projects. This would in turn prevent the lock-in of investments in higher-emitting production.

If Option 1 cannot be implemented with sufficient ambition in the above stated timeline, we propose a third, interim option: a system of facility-level emissions limits similar to the existing federal coal-fired electricity facility limits.[3] Option 1 could still be developed in parallel and implemented when ready. At that time the facility limits could be rescinded, if found to be redundant with cap-and-trade.

General

1. How do you envision the future of the oil and gas sector in the Canadian economy or your community?

If global climate action and clean energy technology adoption (such as electric vehicle uptake) continues on its current trajectory, a growing number of global oil demand scenarios indicate demand is likely to decline by 2030.[4] As global oil demand declines, the market will become more competitive, and companies that produce the most cost- and carbon-intensive oil will have greater difficulty in maintaining their market share. If the world meets its climate goals, this effect will be even more drastic, and Canada could face significant economic impacts.[5] At present, Canadian oil remains amongst the most carbon intensive globally.[6]

Demand scenarios for gas and LNG exports follow a similar trajectory, with potential variability of demand decline timing, depending on how quickly low-carbon technologies (such as heat

[3] Government of Canada, *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, SOR/2012-167.

[4] International Energy Agency, *World Energy Outlook 2021*. https://www.iea.org/reports/world-energy-outlook-2021

[5] Jean-Francois Mercure et al. "Macroeconomic impact of stranded fossil-fuel assets," *Nature Climate Change* (2018), 8. https://core.ac.uk/download/pdf/162913713.pdf

[6] Mohammad S. Masnadi. et al, "Global carbon intensity of crude oil production." *Science* 361, no. 6405 (2018). https://doi.org/10.1126/science.aar6859

pumps) are adopted. Gas production will be increasingly adjusted to respond to price volatility, and only producing when profitable will become the norm. A larger share of the declining crude oil and natural gas production will be used as feedstock for non-combustion uses, such as chemicals, materials, and fertilizers.

Recent work from the Cambridge Centre for the Environment suggests that fossil fuel importing countries primarily decide when and how quickly fossil fuel markets peak and decline and are incentivized to decarbonize, as opposed to exporters like Canada that have less incentive to decarbonize.[7] Not only do economy-wide decarbonization goals lead to lower emissions, they also improve the trade balance of energy importers and exporters. This is especially true in east Asia and the European Union: their strong net-zero goals will help them import less fossil fuels, which improves their trade balances. Canadian industry needs to invest in decarbonization initiatives now to improve access to those decarbonizing markets, and remain competitive in a shrinking but volatile global market that will demand low emissions and cost.

At present, capital expenditure (which would typically include spending on things like new production facilities, acquisition, and upgrading of existing production facilities and equipment) as a percentage of cashflow in the energy sector — which in pre-pandemic years was regularly above 100% — is now at historically low levels (39% in 2022).[8] Instead, large amounts of cash are being returned to investors in the form of share buybacks and dividend payments. It is unclear if investors will continue to demand this, or if they will return to favouring that the majority of earnings be reinvested in oil and gas capital. However, if this practice does continue — which is possible in the context of rapidly declining oil demand — it will mean that a prosperous oil and gas sector does not lead to as much prosperity for Canadians as it once did, as profits are taken by investors rather than reinvested in jobs-creating projects, with benefits that trickle down to Canadian communities. Capital investment should shift to decarbonizing existing assets, and new assets with lower emissions intensities. It should be noted that emissions reduction projects represent significant opportunities for job creation in the sector. Policy is needed to drive companies to make these investments and ensure ongoing prosperity for local communities, while also safeguarding the medium-long-term competitiveness of the sector.

[7] Jean-Francois Mercure et al., "Reframing incentives for climate policy action," *Nature Energy* 6 (2021). https://doi.org/10.1038/s41560-021-00934-2

[8] Bank of Canada Business Outlook Survey — Second Quarter of 2022. https://www.bankofcanada.ca/?p=227390

2. What do you see as the role of your organization or community in contributing to reducing oil and gas sector emissions in Canada?

For more than 35 years, the Pembina Institute has worked with industry and all levels of government, including Indigenous governments, to help build a clean energy future that protects our climate, and the cities and communities we live in.

Our organization was born out of grassroots organization in response to a major sour gas incident in Alberta. Over the last several decades, we have continued to advocate for stricter regulations in the oil and gas sector to manage the impacts of energy development, and for stronger policies that drive companies to make clean energy investments that ensure prosperity for local communities and that Canada achieves its net-zero goals.

3. What are the benefits or drawbacks of the options outlined in the discussion document?

A key drawback is that discussing regulations in the absence of a clear target is a less efficient approach to engagement and policy design. The design of the policy mechanism is dependent on the intended outcome and level of ambition. We recommend that the overall trajectory and interim targets of the cap be announced as soon as possible, and then the details of policy design developed.

For all options, we recommend that high-performance benchmarks are utilized to inform emissions thresholds or free allocations. This will account for different production processes and improve fairness for firms that invest in early, ambitious emissions reductions. For smaller and aggregated firms where high-performance benchmarks are not possible, we recommend the use of historic facility-level emissions.

Option 1: cap-and-trade

Option 1 (cap-and-trade) provides more certainty about the emissions reductions to be achieved, as the cap would set a finite amount of emissions allowances per compliance period.

Option 1 could also be implemented quicker, in 2024 or early 2025, because it does not require equivalency agreements with the provinces, as it would be a national system. This has an added benefit of reducing the administrative burden associated with negotiating equivalencies. However, this is contingent on going through the policy development process for a brand-new regulation in a quick and efficient policy manner. We recommend drawing on any lessons learned from similar processes in Quebec, Nova Scotia, California, and the EU. In particular, most cap-and-trade mechanisms required adjustments in their early years; for instance, setting up market stability reserves or price ceilings/floors to mitigate oversupply or undersupply of allowances. If Option 1 is chosen, these adjustments should be anticipated.

However, the complexity of layering a national cap-and-trade mechanism on top of the federal Output-Based Pricing System (OBPS) and equivalent provincial systems creates an additional administrative burden. Since this would be an entirely new structure, implementation may be delayed by processes for stakeholder consultation and engagement.

Adjustments to the OBPS would still be crucial, to keep credit markets from being oversupplied as oil and gas facilities accelerate their emission reduction efforts due to the presence of the cap-and-trade system.

Option 1 would also create a single-sector stable emissions allowance market that is exposed to fluctuating global oil prices, which carries some risk. Uncertainties about the allowance market could lead to low stringency in the early years. This could be mitigated by implementing a floor and ceiling on allowance prices, and a carefully planned market stability reserve. This will allow allowances to ramp down ambitiously from year one, and avoid oversupplying allowances (as occurred in the EU and California, which resulted in market issues, including delayed emissions reductions).

Option 1 would also be more consistent with the five-year emissions reduction targets enshrined in the Net-Zero Emissions Accountability Act, if the cap trajectory is aligned with those targets as they are developed.

Additionally, Option 1 could be expanded in the future to progressively include new sectors, with the potential of instituting an economy-wide cap-and-trade system in the future. In the long run, this could be an option to simplify Canada's complex multi-level carbon pricing mechanisms, allowing for the most efficient approach to achieving emissions reduction targets, while rescinding redundant mechanisms over time.

Option 2: strengthened OBPS

Option 2, which involves adjusting current tools, has the benefit of utilizing Canada's already comprehensive and complex carbon pricing mechanisms to achieve additional reductions in the sector. One drawback of this approach is that since the next review is not until 2026, additional meaningful reductions from the oil and gas sector would be delayed until then, at the earliest.

Additionally, adjusting the carbon price for one sector would require amendment of the *Greenhouse Gas Pollution Pricing Act*, presenting a potential legal roadblock for Option 2 which may delay implementation further. Adjusting existing measures for one sector could disrupt the marginal price signal, undermining the benefits of economy-wide pricing systems by creating different prices in different sectors.

Option 2 provides less certainty about the amount of emissions reductions to be achieved, although rigorous forecasting can estimate reductions that would result from a certain price.

With regards to the proposed facility-level emissions forecasting requirement, which would be utilized to help set the sector-specific price in Option 2, we recommend that facility forecasts be evaluated against companies' reported investments and final investment decisions for large projects (especially CCUS megaprojects) in order to ensure credible forecasting.

4. Of the two approaches outlined, is there an approach your organization or community would prefer?

The Pembina Institute recommends the option that can be implemented in the most timely manner, while providing as much certainty as possible regarding emissions reductions and maintaining the integrity of Canada's carbon pricing systems. Option 1 can likely come into force more quickly than Option 2 and would not require amendment of the *Canadian Environmental Protection Act* (CEPA). Conversely, Option 2 would be delayed until the 2026 review of the OBPS at earliest, would likely require amendment of the *Greenhouse Gas Pollution Pricing Act* (GGPPA), and would also require provincial equivalency negotiations.

If, however, Option 1 cannot be designed and implemented quickly (with a start date of 2025 at the latest), then we also recommend an interim approach of setting facility-level emissions intensity limits under CEPA, described in further detail in Question 5.

5. Do you have suggestions on how to improve the options outlined?

Due to the complexity of creating a new pricing system for the oil and gas sector in Canada's climate policy landscape, both options will likely take years to develop and to implement. However, given Canada's international climate commitments, and the corresponding ambition level of the emissions reduction targets outlined in the 2030 Emissions Reductions Plan, time is in short supply. Whichever form the cap takes, it should be designed and implemented as soon as possible, while still allowing for appropriate consultation and engagement with stakeholders.

Option 1: cap-and-trade

We recommend that under Option 1, smaller facilities be allowed to aggregate to reduce their administrative burden, similar to what is allowed under Alberta's Technology Innovation and Emission Reduction (TIER) system. New sub-sector classifications should be developed based on production classes with distinct emissions profiles and asset characteristics (eg. light and medium oil, cold heavy oil produced with sand (CHOPS), conventional natural gas, tight gas, etc.).

We recommend proceeds from a cap-and-trade system be returned to the provinces in a similar fashion as proceeds from the OBPS, where provinces are allocated proceeds based on where facilities are located, and with similar constraints as GGPPA.

In Option 1, cordoning off the oil and gas sector does increase the risk of volatility in the carbon market. Global oil prices or a potential influx of emissions reductions (such as those that would arise from CCUS projects) risks over- or under-supplying the market, leading to a much higher or lower price of carbon than in other sectors. Many emissions trading schemes have instituted price ceilings and floors to account for this volatility, although this may be difficult to manage given the smaller number of participants in a sector-specific pricing system compared to economy-wide pricing systems.

Option 2: strengthened OBPS

If Option 2 is chosen, we recommend that the process of developing and communicating standards with provincial governments start early in 2023, to foster policy certainty and allow for adjustments in equivalent provincial pricing systems.

It is crucial that Option 2 maintains the minimum marginal price signal. If emissions thresholds are too high for the sector (or compliance options are too flexible) and are not reduced in alignment with the cap trajectory, the price signal is at risk of being weakened due to a potential lack of demand for emissions performance credits. To achieve this we recommend an annual tightening rate for the sector that is aligned with the ERP's 2030 emissions reduction goal of 45% below 2005 levels, as well as net-zero by 2050, be included in the benchmark criteria. Assuming a coming-into-force date of 2026 and an initial sectoral emissions level of 203 Mt CO_2e (as in 2019), the annual tightening rate should be 8-10% to achieve a 45% reduction in sectoral emissions from 2005 levels by 2030. This ambitious tightening rate is needed to maintain stability in the pricing system and is a consequence of emissions continuing to grow in the sector.

Option 3: facility-level emissions intensity limits under CEPA

If Options 1 or 2 cannot be quickly designed (with an implementation date of 2025 or earlier), we recommend the introduction of facility-level emissions limits, to be implemented immediately and incentivize the earliest possible decarbonization investments in the sector, during which time Option 1 would also be finalized.

Under this interim option, output-based emission limits would be set for oil and gas facilities, with the intention that these limits serve as a federal backstop, and that the provinces strengthen their own carbon pricing systems to achieve equivalent outcomes. These facility limits would decline from current levels on a trajectory that achieves Canada's cap on those emissions in 2030, and could require new facilities to be near-zero emissions when built. Modelling to set these limits must consider oil and gas production forecasts, with facility limits reduced to account for emissions from additional oil production, based on the most recent Canada Energy Regulator forecast.

Limits should take into account all Scope 1 and 2 emissions associated with oil production, including vented, flared, and leaked greenhouse gases. These new facility limits would serve as regulatory backstops, should forecasts indicate Canada is off-track to achieve the oil and gas emissions cap. This approach should leverage the same data and reporting as the carbon pricing systems, including the use of aggregate compliance (similar to Alberta's TIER) to limit the administrative burden. Forecasting and checks to determine if Canada is on-track to achieve the oil and gas cap could integrate with periodic equivalency reviews, but should be on an annual basis until the sector's emissions are on-track for five consecutive reviews. Equivalency reviews could then take place biannually.

Penalties for facilities exceeding their limits only come into force if federal ECPro modelling (used by ECCC to develop Canada's emissions forecasts and to assess provinces' carbon pricing equivalency) indicates that the oil and gas sector will not achieve Canada's cap (alternatively, this sector modelling could be supplemented with facility-level emissions forecasts from large emitters, if those are deemed sufficiently reliable). Those penalties would be incremental to compliance obligations in the carbon pricing system. They should apply the carbon price to facility emissions that exceed the facility's limit, but with a multiplier that scales up this amount proportionately depending on how much the facility's emissions exceed its limit.[9]

These facility limits could be designed under CEPA immediately, come into force by the end of 2024, and would not replace other legislation and policy that applies to oil and gas facilities, such as carbon pricing. Because penalties for exceeding limits would not come into force unless limits are exceeded, and also would be scaled based on the level of exceedance, this approach is inherently flexible, so additional compliance flexibility using offsets should not be allowed. Provincial equivalency could be considered as an option.

6. What potential short or long-term socio-economic impacts do you foresee or anticipate for particular regions or population groups resulting from an oil and gas emissions cap in general, and more specifically, the two proposed regulatory options?

Socio-economic impacts of the energy transition are already being felt by Canadians, as a result of decreasing investments in fossil fuel projects, changing labour market dynamics, and global supply and demand trends. As the world continues to accelerate climate action, these trends will continue, and jobs will likely decline further in the oil and gas sector. However, if companies invest in decarbonization, this would create additional job opportunities. Stringent policy, like this sectoral emissions cap, is needed to drive these investments and prevent

[9] Facility Penalty = [Facility Emissions - Facility Limit x Facility Production] x [Facility Emissions / Facility Limit / Facility Production] x Federal Carbon Tax

leakage of capital to investors outside of Canada. Without stringent policy, the energy transition will continue, but the likelihood that Canadians — particularly those who have traditionally relied on resource extraction industries for their economic prosperity — will experience the fullest economic benefits of clean technology and decarbonization projects will be diminished.

Labour market dynamics are already changing in Canada. The number of direct and indirect jobs in oil and gas is declining, driven by lack of investment in new megaprojects, increasing automation, and company mergers. Conversely, while carbon pricing does affect the types of jobs available, studies indicate that carbon pricing does not negatively affect overall employment in the longer term. One study that examined the impact of implementing B.C.'s carbon tax in 2008 found that the tax actually led to a small increase in overall employment from 2007 to 2013.[10] The World Bank's Carbon Pricing Leadership Coalition, in a survey of carbon pricing studies, also found little evidence to suggest that carbon pricing impacts either employment or competitiveness, as long as policies are well-designed and targeted incentives for decarbonization are available for firms.[11] And there are employment opportunities in the decarbonization space as well; for example, companies providing methane emissions management (many based in Alberta) predict job growth as a result of upcoming federal methane regulations.[12]

Oil demand is likely to decline in the short term (2022-2030).[13] The introduction of the Inflation Reduction Act (IRA) in the United States is likely to accelerate the long-term decline in demand for oil in the U.S. Many other countries, including China, have also set net-zero commitments, and the adoption of electric vehicles is expected to increase exponentially this decade.[14]

We can also expect global demand for oil to decline in the longer term. Scenarios from the International Energy Agency (IEA), as well as international oil majors bp and Equinor indicate

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[10] Akio Yamazaki, "Jobs and Climate Policy: Evidence from British Columbia's Revenue-Neutral Carbon Tax" *Journal of Environmental Economics* 83 (2017). https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2958020

[11] Carbon Pricing Leadership Coalition, *What is the Impact of Carbon Pricing on Competitiveness?* (2016), 2. https://pubdocs.worldbank.org/en/759561467228928508/CPLC-Competitiveness-print2.pdf

[12] Methane Emissions Leadership Alliance, *Canadian Methane Jobs Market Analysis.* https://www.methanealliance.com/case-studies/canadian-methane-jobs-market-analysis

[13] International Energy Agency*, Net Zero by 2050* (2021*).* https://www.iea.org/reports/net-zero-by-2050; bp, *Energy Outlook 2022.* https://www.bp.com/en/global/corporate/energy-economics/energy-outlook.html; Equinor, *Energy Perspectives 2021.* https://www.equinor.com/sustainability/energy-perspectives-previous-reports

[14] Bloomberg New Energy Finance, "Net-zero road transport still possible, as electric vehicles set to quintuple by 2025," June 1, 2022. https://about.bnef.com/blog/net-zero-road-transport-by-2050-still-possible-as-electric-vehicles-set-to-quintuple-by-2025/

that — assuming a rate of climate action and technology development similar to the last several years (with the Paris Agreement as a turning point) — global demand for oil will begin long-term, permanent decline by 2030.[15]

Working from a net-zero by 2050 target, the IEA's seminal net-zero scenario forecasts that oil demand globally will need to decline much more rapidly and drastically—to about 74 mb/d in 2030 and 24 mb/d in 2050 (from about 98 mb/d in 2019).[16]

Under the IEA's *Net Zero by 2050* scenario, natural gas demand increases rapidly to 2030 and then declines by about 60% from 2020 levels by 2050 (about 5% annually in the 2030s) (Figure 1).

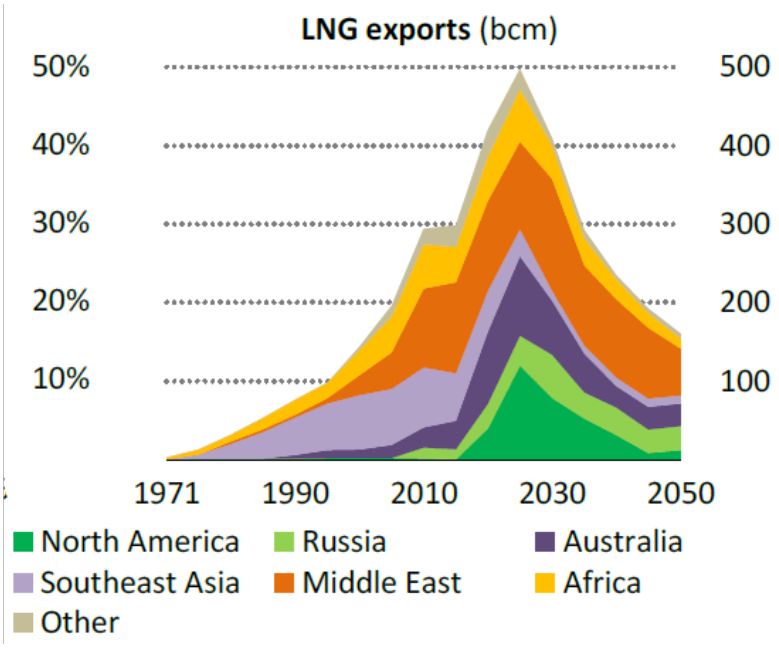

Figure 1: Natural gas exports in the International Energy Agency's *Net Zero by 2050* Scenario

Source: IEA[17]

In the IEA's most recent *Announced Pledges* scenario, which assumes that climate commitments made by governments around the world will be met in full, demand for natural gas peaks soon after 2025 and then declines to about 20% of the global energy mix in 2050.[18]

[15] IEA, *Net Zero by 2050*; bp *Energy Outlook* 2022; Equinor, *Energy Perspectives 2021.*

[16] *Net Zero by 2050,*

[17] *Net Zero by 2050*, 175.

[18] *World Energy Outlook 2021,*

Scope of coverage

7. Should consideration be given to facility emission thresholds to set different approaches and requirements for small versus large emitters?

Yes; small facilities should be allowed to aggregate to reduce the administrative burden and cost of compliance, as well as avoid large volumes of reports from small facilities that individually reveal little new information about the broader emissions trajectory, compared with aggregated reports. However, new sub-sector classifications should be developed based on production classes, with distinct emissions profiles and asset characteristics (e.g. light and medium oil, cold heavy oil produced with sand (CHOPS), 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 government authorities needs to happen frequently and systematically, and with appropriate human and financial resources.

8. Should the cap include petroleum refineries and natural gas transmission pipelines?

The cap should include transmission pipelines. While this is a comparatively small source of emissions, there are opportunities for electrification, especially in Quebec and Ontario where there is reasonable access to the grid. However, where mitigation options are limited (i.e. no grid access), pipelines may need more access to offsets than other facilities.

Refineries should not be included in the cap. The risk of carbon leakage is high, and Canada's principal competitors in the U.S. are largely not subject to as stringent carbon pricing schemes. Additionally, mitigation options are limited, and implementing an even higher price on refineries makes refineries vulnerable to closure. There are also other repercussions associated with the loss of domestic refining capacity, such as increased risk of fuel supply disruption and increasing domestic fuel costs.[19]

[19] Canadian Fuels Association, "Canada's energy security could be at risk," April 27,2017 https://www.canadianfuels.ca/news-commentary/canadas-energy-security-could-be-at-risk-heres-why/

9. Are there other considerations relevant to determining the scope of the cap?

The scope of the cap should be clarified to include liquified natural gas (LNG). There is significant interest in LNG development on Canada's east and west coasts. LNG terminals also have proven mitigation opportunities, namely through electrification. Excluding LNG from the cap would risk creating a loophole for large sources of emissions if the proposed LNG projects are built.

Additionally, the cap should cover oilsands fugitive emissions from tailings ponds, and orphaned/abandoned wells and other facilities, both of which constitute significant environmental liabilities and are included in Canada's National Inventory Report.[20]

Emissions cap trajectory

10. What are the relevant considerations for determining a GHG emissions trajectory, particularly over the first 10 to 15 years?

The cap's trajectory should align with Canada's climate commitments for 2030 and 2050. The Emissions Reduction Plan (ERP) forecasts that, without implementing an oil and gas cap and a CCUS investment tax credit, the oil and gas sector's emissions will drop by 31% relative to 2005 levels. However, the ERP projects a baseline of oil and gas production in 2030 that is not aligned with a net-zero future. The cap trajectory should be informed by a realistic production baseline given the accelerating momentum of the global energy transition. The next iteration of the Canada Energy Regulator's *Energy Futures* report will include a fully-modelled net-zero scenario, which can inform cap levels in the future. However, given that the next *Energy Futures* is not due to be released until spring 2023, we recommend that the International Energy Agency's forecasts are utilized initially so that cap levels to 2030 can be announced as soon as possible.

The sector needs to do its fair share — oil and gas emissions increased by almost 19% between 2005 and 2019. While implementing an oil and gas-specific pricing system is at risk of higher volatility than the economy-wide carbon market, the sector is Canada's highest-emitting, and unlike most other parts of the economy, emissions have continued to grow. As a result, a sector-specific policy is necessary to incentivize the kind of action from industry that would precipitate emissions reductions.

[20] Environment and Climate Change Canada, *National Inventory Report* 2022, 89. https://publications.gc.ca/collections/collection_2021/eccc/En81-4-2019-1-eng.pdf

Additionally, there is significant emissions reduction potential in the oil and gas sector that can be unlocked in the short term[21]:

- Up to 22 Mt per year in carbon capture potentially coming online in Alberta by 2030, with more projects in development.[22]
- At least a 75% reduction in oil and gas methane emissions by 2030, with evidence growing that near-zero methane is not only possible but cost-effective.[23] The Oil and Gas Climate Initiative, a group of 12 major global oil and gas producers including Shell, Repsol, and Saudi Aramco, aim to reach near-zero methane emissions in their operations by 2030.
- Electrification of engines and compressors used in the production, processing, and transport of natural gas and conventional oil could reduce emissions by 18 Mt per year.
- Fuel switching from petroleum coke to abated natural gas could reduce emissions by several Mt per year before 2030.

Due to the current high proportion of Canada's emissions that are attributable to oil and gas production, coupled with the existence of significant emissions reduction potential and associated technologies in the sector, we recommend that the cap's trajectory align with the economy-wide target of a 40-45% reduction by 2030. Beyond 2030, the cap trajectory should align with the interim reduction targets (key milestone years are 2035, 2040, 2045) set out pursuant to the Net-Zero Emissions Accountability Act.

> 11. How should the trajectory of the oil and gas emissions cap be designed to support Canada's 2030 targets and achieve net-zero by 2050? Should the cap set annual or multi-year emission levels?

We recommend that the cap set multi-year emission levels, to allow flexibility for the private sector and allow for larger, more complex projects (like CCUS) to come online.

Option 1: cap-and-trade

Initially, a two- or three-year phase would allow for adjustments and flexibility, especially with regards to an influx of emissions reduction projects expected to come online before 2030. There is precedent in cap-and-trade systems for starting with shorter phases before transitioning to longer; Quebec and California's cap-and-trade system began with a two-year compliance

[21] Jan Gorski and Janetta McKenzie, *Decarbonizing Canada's oil and gas supply* (Pembina Institute, 2022). https://www.pembina.org/pub/decarbonizing-canadas-oil-and-gas-supply

[22] See the Alberta Major Projects Inventory (https://majorprojects.alberta.ca/) and Emissions Reduction Alberta's Carbon Capture Kickstart Program (https://www.eralberta.ca/funding-technology/carbon-capture-kickstart/)

[23] Jared Connoy, Janetta McKenzie, and Jan Gorski, *Success in Eliminating Methane in Alberta's Peace River Region* (Pembina Institute, 2022). https://www.pembina.org/pub/success-eliminating-methane-albertas-peace-river-region

period, then transitioned to three years. In the European Union Emissions Trading Scheme (EU ETS) the first two trading periods were two and four years respectively, followed by seven years and now 10 years in Phase 4. In each phase, the cap and annual reduction rate can be set.

Option 2: strengthened OBPS

Similarly, multi-year emissions levels should be set to allow flexibility for industry, while maintaining a linear reduction to net-zero by 2050 and incentivizing early action.

In either option, we recommend multi-year emission levels that align with the key milestones laid out in the Net-Zero Emissions Accountability Act (2026, 2030, 2035, 2040, 2045).

> 12. Should the trajectory be fixed out to 2050, or should the approach include steps to ratchet up the trajectory at one or more fixed intervals?

The trajectory should pass through the 2030 target in order to incentivize both early action on emissions reduction projects that will yield near-term results, as well as longer-term investment into more complex technologies like CCUS. If the cap's trajectory is weighted towards post-2030 or 2040, significant emissions reductions will not be realized until far too late in Canada's path to net-zero and Canada's cumulative level of emissions will end up higher. More costly technology like CCUS does have a long lead time, but policy tools exist (like the CCUS ITC announced in Budget 2022) that provide support for these investments. And opportunities for early, low-cost action are available to industry now — for instance, in abating methane, electrification, fuel switching, and other efficiency measures — while other technologies are being deployed.

Competitiveness and carbon leakage

> 13. What design features should be considered to maintain Canadian competitiveness and minimize the risk of carbon leakage?

As global oil and gas demand declines, demand for Canadian oil and gas will as well; and the worst-performing facilities from an emissions perspective will become uneconomic due to high emissions intensity and high costs. In order to stay competitive in a shrinking market — one that is increasingly incorporating climate change and emissions reduction imperatives into business and policy decisions — the Canadian oil and gas sector needs to urgently prioritize decarbonization initiatives. This emissions cap will help the sector prepare for a net-zero world.

The OBPS is currently designed to lower the cost of emissions reductions for sectors that are considered emissions intensive and trade exposed (EITE) by allowing facilities to emit a portion of their emissions for free. Under Option 2, we recommend that current output-based standards

be used as a starting point, but be ratcheted down by way of an annual tightening rate (of at least 8-10%, assuming a 2026 implementation date) to ensure emissions credit prices remain aligned with the federal carbon price, align reduction targets with 2030 ERP goals, and provide greater predictability and carbon pricing certainty for investors. Alternatively, if a strong and predictable annual tightening rate cannot be provided in OBPS and benchmark criteria, then ECCC should emphasize its proactive commitment to frequently monitoring the provincial carbon credit systems and ensuring credit prices remain aligned with the federal carbon price.

When a border carbon adjustment mechanism is implemented by Canada and our major trading partners, output-based pricing under Option 2 should be phased out as sectors will be protected from competitiveness concerns, and a simple carbon tax should be implemented instead. Under Option 1, allowances should initially be partially freely allocated, and transition to be fully auctioned once a border carbon adjustment mechanism is in force. Both the United States and the EU are developing policies that would impose tariffs on certain commodities and goods imported from nations with weak industrial emissions policies.

Regarding methane, the United States EPA has proposed ambitious methane regulations, and the Inflation Reduction Act includes a methane fee program to come into force 2024. We recommend that the federal methane regulations aim to achieve near-zero methane by 2030, since there will be little trade exposure in this area from Canada's largest trading partner.

14. What compliance flexibilities should be allowed, and what conditions should determine eligibility?

We recommend that the types of offsets utilized should be limited, aligned with the Oxford Principles for Net Zero Aligned Carbon Offsetting.[24] Carbon removal projects should be prioritized, and offsets should be verifiable, correctly accounted for, and have a low risk of non-additionality.[25]

A practical step to achieve this would be to require that at the outset of this cap, at least 10% of offsets used for facility compliance must come from carbon dioxide removal (CDR) projects. Additionally, targets should be set to ratchet this up by 10% per year, so that, by 2035, emission reduction offsets will be fully phased out and the system will focus on high-quality CO_2 removals that are aligned with net-zero. Achieving this goal requires proactive focus on developing CDR offset protocols and projects.

[24] Myles Allen et al., *The Oxford Principles for Net Zero Aligned Carbon Offsetting* (2020), https://www.smithschool.ox.ac.uk/sites/default/files/2022-01/Oxford-Offsetting-Principles-2020.pdf

[25] *The Oxford Principles for Net Zero Aligned Carbon Offsetting,* 5.

Offsets projects should also be limited to within the oil and gas sector in order to achieve in-sector emissions reductions, consistent with the stated intent of the oil and gas emissions cap.

15. Should the use of compliance flexibilities decline over time? If so, to what extent?

The use of compliance flexibilities should decline in both Options 1 and 2. Such restrictions are common in emissions trading systems. This is in line with global best practices from cap-and-trade systems in Quebec, California, and the European Union, and with requirements already enshrined in the OBPS regulations with regards to Option 2.

In Option 2, limits on compliance flexibilities in the OBPS already exist, and we recommend that these limits be tightened more quickly. We recommend a stricter limit on offset use for compliance, one that is consistent with driving actual reductions and transformation at the facility level. In the context of the climate emergency, every ton of carbon mitigated should count not toward maintaining the status quo, but toward meeting climate targets.

Regarding Option 1, limits on offset use are integrated into many cap-and-trade systems. In California, the use of offsets was limited to 8% for first three compliance periods, 4% for the fourth, and is planned to increase to 6% in 2026. A 2020 rule now requires half of the offset quota to come from projects that provide direct environmental benefits to the state (current protocols include forestry, livestock, ozone-depleting substances, mine methane capture, rice cultivation).

In Quebec, the use of offsets as a compliance option is limited to 8%, in order to ensure that most emission reductions are achieved in sources covered under the provincial cap-and-trade. In the EU ETS, the use of international offsets is no longer allowed from phase four, which started in 2021.

Under both Options 1 and 2, we recommend limiting the amount of offsets used in a given compliance period to 8%, in line with California and Quebec's initial limits, with a reduction of that limit over time. The use of non-CDR offsets should be reduced over time in either Option.

Other limits on compliance flexibilities exist in current pricing systems, including on the banking of allowances for future use. Regarding Option 1, the EU, Quebec and California limit the number of allowances that can be held in excess of credits required to meet compliance obligations. Additionally, in order to maintain market stability and prevent a consolidation of market power in a few large firms, auction purchase limits are instituted based on total available allowances available at auction.

For Option 2, limits on banking already exist in both the federal OBPS and provincial systems. Alberta's TIER system includes a credit expiry timeline for both EPCs and emission offsets, to

limit banking in the longer term. The federal OBPS also includes expiry dates for different types of credits

We recommend that under Option 1, the number of allowances that can be held in excess of credits required for compliance be limited and that bid limits be instituted. Under both options, we recommend credit expiry timelines similar to those in the federal OBPS, to be reviewed as the oil and gas credit market takes shape.

16. Under a potential cap-and-trade option, should distribution of allowances be done through auction, free allocation, or a combination of the two?

Most cap-and-trade systems distribute emissions allowances through a combination of free allocations, usually to support emissions-intensive and trade-exposed sectors, and auctioning.

The EU, Quebec, and California's cap-and-trade systems all have a combination of auctioning and free allocations, with free allocations ratcheted down over time.

Over the entire EU ETS Phase 4 (2021-2030), about 57% of general allowances are to be auctioned, encompassing all sectors including EITE (except for aviation).[26] 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.[27] 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, which included allowances owned by the California Air Resources Board (about 37%) and allowances consigned to auction by utilities (about 25%).[28] Allowance vintages from previous, current, and future compliance years are auctioned in single-round, sealed-bid format, and the allowance budget is decreasing (and the rate of that decrease is increasing; a 3% reduction in 2016, 3.5% in 2020).[29]

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

[27] 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

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

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

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).

The Pembina Institute recommends that in a cap-and-trade system, a combination of free allocation for EITE activities and auctioning be utilized, with both overall allowances and the number of free allocations to decline over time. We recommend that initially, free allocations should align with the federal OBPS benchmarks, for efficiency and to reduce the administrative burden of designing new benchmarks. There is precedent for this type of cross-pricing system alignment — the Netherlands carbon tax used the EU ETS to determine initial emissions coverage.[30] The amount of free allocations distributed should then decline over time in alignment with the cap trajectory. Additionally, a market stability provision should be included from the outset, in order to maintain price certainty. The overall allowances should decline annually to 2030 to achieve the ERP economy-wide goal of a 45% reduction from 2005 levels, on the path to net-zero by 2050.

Policy coherence and coordination across jurisdictions

> 17. Would there be merit in excluding or taking an approach that results in lower compliance costs for emissions generated from the production and processing of fuels used to support the development of clean fuels (e.g., natural gas required for low carbon hydrogen production)?

Hydrogen from natural gas with CCS should not be incentivized under the cap in a manner that provides preferential treatment for this type of hydrogen at the expense of hydrogen generated from renewable electricity. Canada has some of the highest global potential for green hydrogen, which should be the focus of Canada's hydrogen strategy (and defining clean, low-carbon hydrogen is a key piece of the recent Canada–Germany Hydrogen Alliance).

Any investment in hydrogen from natural gas with CCS will have to consider the full life cycle impacts of hydrogen production and distribution. If hydrogen with natural gas and CCS is to be able to compete as a contributing pathway to a net-zero future, significant emissions must be addressed, including emissions from plant operation and upstream natural gas extraction. Upstream emissions from natural gas extraction will have to be virtually eliminated and a rate of carbon capture above 95% will need to be employed.[31]

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[30] World Bank, *State and Trends of Carbon Pricing 2021*. https://openknowledge.worldbank.org/handle/10986/35620

[31] Jan Gorski, Karen Tam Wu, Tahra Jutt, *Carbon intensity of blue hydrogen production* (Pembina Institute, 2021), 9. https://www.pembina.org/pub/carbon-intensity-blue-hydrogen-production

18. How should the Government of Canada ensure that the cap incents investments in diversification and other preparations for a clean energy transition?

If the cap is designed with a sufficient level of ambition (i.e. 45% reduction from 2005 levels by 2030; net-zero by 2050) and implemented quickly and stringently, it will incentivize early and sustained action to decarbonize and diversify. Policy certainty and a cap trajectory that prioritizes near-term emissions reductions will encourage the oil and gas sector (and beyond) to accelerate preparations for the energy transition. Slow and weak policy favours incumbent technologies that are higher emitting, at the expense of prolonging a "valley of death" for low-carbon investments that need higher carbon prices and emissions reduction policy ambition to be competitive.

This cap is one of several policy tools that will prepare Canadian oil and gas to be competitive in a shrinking market. The IPCC, IEA, and other credible net-zero scenarios see oil and gas demand fall significantly by 2050, even with deployment of higher-cost carbon removal technologies. Even assuming a similar pace of policy implementation, technology development, and global market trends, multiple scenarios indicate a long-term decline in oil demand before 2030.[32] The demand that remains will likely have more stringent conditions regarding climate safety and emissions intensity; conditions that are more likely to be met by a sector already heavily invested in decarbonization initiatives due to an ambitious emissions cap.

Additionally, as the cost of renewable energies drops[33] and investors place increasing value on a stable climate, sectors (both within oil and gas and without) will have the incentive to diversify and innovate in order to stay competitive.

19. How would each potential cap approach interact with other climate measures?

Under Option 1, the stringency of the cap-and-trade system and existing pricing mechanisms would likely require ongoing adjustment. As emissions from oil and gas decline to meet the cap-and-trade cap, OBPS systems may need to tighten their output-based standards to maintain the price signal. In theory, the cap-and-trade system and other pricing mechanisms would align with regards to stringency, but, in practice, adjustments to output-based standards

[32] *World Energy Outlook 2021*.

[33] International Renewable Energy Agency, "Renewable Power Remains Cost-Competitive amid Fossil Fuel Crisis," July 13, 2022. https://www.irena.org/newsroom/pressreleases/2022/Jul/Renewable-Power-Remains-Cost-Competitive-amid-Fossil-Fuel-Crisis

would be critical to maintain integrity and prevent a crash in credit prices in either the OBPS markets or the national cap-and-trade market.

A national cap-and-trade system will interact with the existing federal and provincial pricing systems and the clean fuel regulations (CFR). When those systems have differing credit prices and stringencies, they will likely interact in inefficient and potentially unpredictable ways that will create investment uncertainty. The details of how these two policies will "stack" are essential to understanding the scale of this uncertainty, and transparent modelling, planning, and periodic review of their interaction will be important.

A market stability provision (like the Market Stability Reserve in the EU ETS) should be established to add or remove allowances from the cap-and-trade market in a given year, to help maintain market stability. Also, existing output-based standards in the OBPS and equivalent provincial systems may need to be adjusted if the cap-and-trade system over-corrects. The cap will likely lead to a larger supply of compliance category 1 credits in the CFR, and ECCC should consider options to ensure that credit market continues to attract investments that reduce Canada's fuel and transportation sector emissions.

Under Option 2, there will likely be few new interactions with other climate measures. However, there is the possibility that emissions performance standards for other sectors may need to be adjusted to maintain the overall price signal, and CFR stringency may need to be adjusted if its market is at risk of oversupply from oil and gas sector credits.

20. What opportunities exist for coordination among federal and provincial and territorial measures?

With regards to emissions forecasting, which is proposed to be a critical variable for setting the oil and gas-specific price, we are concerned that given the unpredictable nature of oil and gas supply and demand, and the impact of broader economic trends and crises on capital availability, facility-level forecasting should not initially be depended upon to determine if the sector is on-track to achieve its cap targets. We recommend that the federal government engage with the provinces to develop the most accurate and thorough data collection methodologies, forecasting and reporting requirements. Once it is demonstrated that those facility forecasts become a dependable means of improving the government's forecasting, they should be used.

Implementation

21. How should a cap on GHG emissions be implemented to maximize emission reductions while avoiding potential challenges related to layering of multiple policies and regulations?

Under either Option, overlap with existing policies is inevitable and should therefore be mitigated.

The forthcoming federal methane regulations will overlap with the scope of the cap. We recommend that ambitious methane regulations continue to be developed and come into force in 2025, with additional reductions required in 2026 that go beyond the current 2025 methane target, achieve near-zero methane emissions by 2030, and have an emphasis on improving measurement techniques and emissions inventories. Methane should eventually be included in the scope of the cap (by 2030 at the latest) to capture any remaining opportunities and achieve near-zero methane emissions.

Option 1: **cap-and-trade**

The stringency of the cap-and-trade system and existing pricing mechanisms would likely require ongoing adjustment. As emissions from oil and gas decline to meet the cap-and-trade cap, OBPS systems may need to tighten their output-based standards to maintain the price signal. In theory, the cap-and-trade system and other pricing mechanisms would align with regards to stringency, but in practice adjustments to output-based standards will likely be required in order to maintain integrity in both the OBPS markets and the national cap-and-trade market.

A national cap-and-trade system will interact with the existing federal and provincial pricing systems and the clean fuel regulations and OBPS. When those systems have differing credit prices and stringencies, they will likely interact in inefficient and potentially unpredictable ways that will create investment uncertainty. Both the cap-and-trade and OBPS would act on each other, introducing considerable uncertainty which may impact the functioning of the OBPS. The details of how these two policies will "stack" are essential to understanding the scale of this uncertainty, and transparent modelling, planning, and periodic review of their interaction will be important.

A market stability provision (like the Market Stability Reserve in the EU ETS) should be established to add or remove allowances from the cap-and-trade market in a given year to help maintain market stability. Also, existing output-based standards in the OBPS and equivalent provincial systems may need to be adjusted if the cap-and-trade system over-corrects. The cap will likely lead to a larger supply of compliance category 1 credits in the CFR, and ECCC should

consider options to ensure that credit market continues to attract investments that reduce Canada's fuel and transportation sector emissions.

Option 2: strengthened OBPS

There will likely be few new interactions with other climate measures. However, there is the possibility that emissions performance standards for other sectors may need to be adjusted to maintain the overall price signal, and CFR stringency may need to be adjusted if its market is at risk of oversupply from oil and gas sector credits.

> 22. What other factors related to implementation should be considered in developing an approach to cap and cut GHG emissions from the oil and gas sector?

The cap levels for 2026 and 2030 should be announced before the end of 2022, with regulations drafted in 2023. Acting early and ambitiously will signal that investments in decarbonization must occur now in order to result in emissions reductions before 2030.[34] Critical technologies take time to develop and bring online, and these investments need to begin now to set up the sector for ambitious emissions reductions in the next three decades.

[34] Chris Severson-Baker, Isabelle Turcotte, Simon Dyer, *Recommendations on principles to guide the implementation of an oil and gas cap* (Pembina Institute, 2022). https://www.pembina.org/pub/recommendations-principles-guide-implementation-oil-and-gas-cap