Top TIER

Federal-Alberta Memorandum of Understanding opens up new opportunities for low-carbon growth in Alberta

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About Clean Prosperity

Clean Prosperity is a Canadian climate policy organization that advocates for pragmatic solutions to grow the low-carbon economy. Learn more at CleanProsperity.ca.

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Abbreviations

ACCIP	Alberta Carbon Capture Incentive Program
ACTL	Alberta Carbon Trunk Line
CCfD	Carbon contract for difference
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization, and storage
CFR	Clean Fuel Regulations
CO_2	Carbon dioxide
CO_2e	Carbon dioxide-equivalent
DAC	Direct air capture
EOR	Enhanced oil recovery
FOAK	First of a kind
GHG	Greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
ITC	Investment tax credit
MAC	Marginal abatement cost
MOU	Memorandum of understanding
Mt	Megatonne
$MtCO_2e$	Megatonnes of carbon dioxide equivalent
OBBBA	One Big Beautiful Bill Act
RNG	Renewable natural gas
SAGD	Steam-assisted gravity drainage
SMR	Small modular reactor
TIER	Technology Innovation and Emissions Reduction (regulation)
WACC	Weighted average cost of capital
WHR	Waste heat recovery

Executive summary

The memorandum of understanding (MOU) signed by the federal and Alberta governments in November 2025 offers a once-in-a-generation opportunity to strengthen Alberta's industrial base and build a more resilient and competitive economy. The province can move immediately to advance projects of national interest, develop new export markets, create jobs, and build generational low-carbon and conventional energy infrastructure.

In the MOU, Alberta committed to strengthening its Technology Innovation and Emissions Reduction (TIER) carbon market to ensure a minimum effective credit price of $130 per tonne. This is a potentially momentous breakthrough for Alberta's economy. Carbon credit prices — not the headline price — are what matter most to project proponents and investors.

Unleashing low-carbon investment in Alberta hinges on the long-term value of TIER credits. We calculate that credit prices in the range of **$130 to $150 per tonne could unlock over $90 billion** in low-carbon capital investment and **reduce over 70 megatonnes of emissions annually** in oil and gas extraction, chemical manufacturing, petroleum refineries, pipelines, and cement — including Phase 1 of the Pathways Alliance carbon capture project.

With carbon credit prices in the range of…	Carbon markets drive capital expenditures of …	Carbon markets drive annual reductions of…
$80 to $100/tonne	$5.6 billion	3.4 Mt
$130 to $150/tonne	**$90.9 billion**	**70.9 Mt**

Using marginal abatement cost (MAC) and project finance modeling, **we sort these potential investments into three technology categories:**

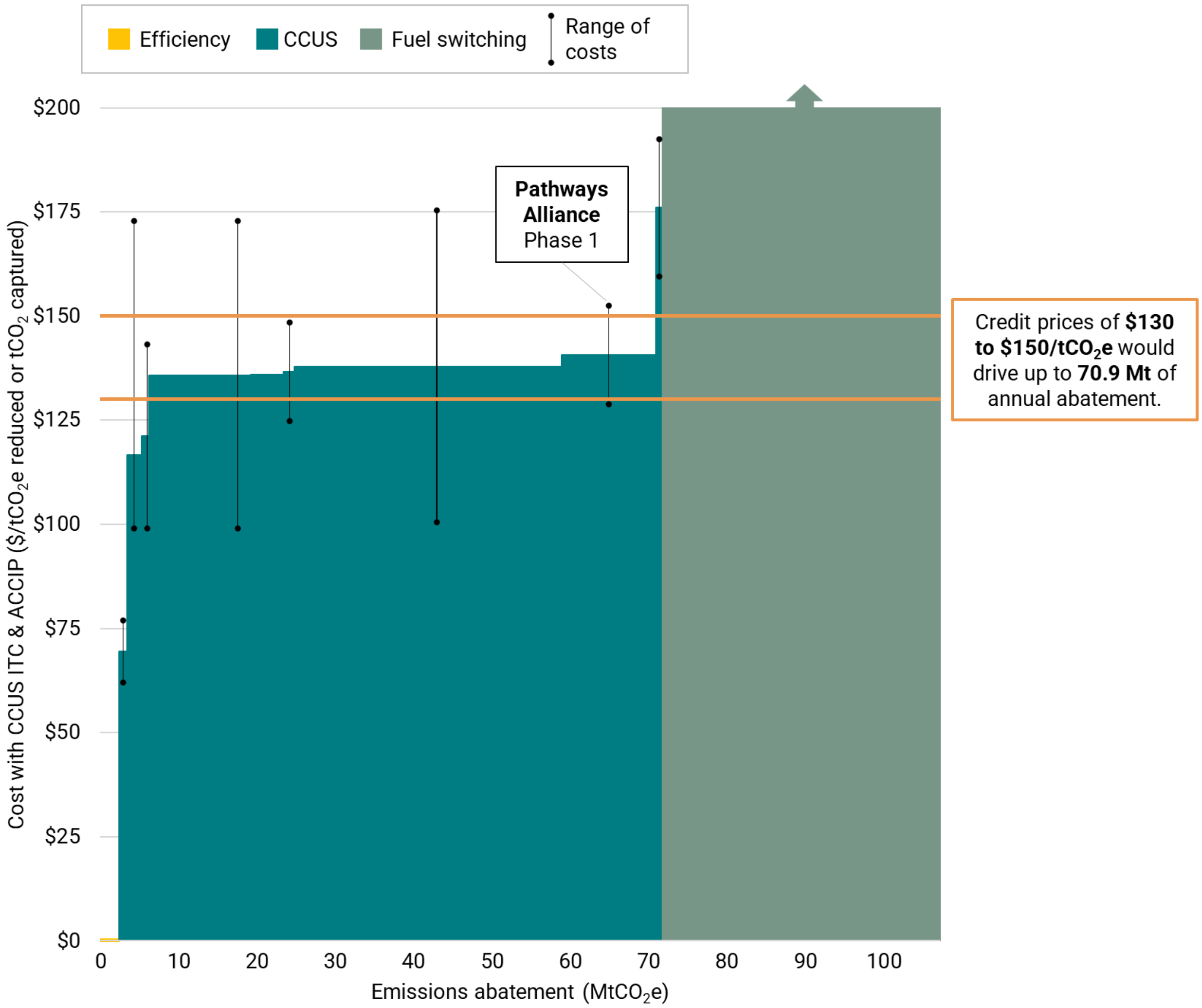
1. **Efficiency**
2. **Carbon capture, utilization, and storage (CCUS)**
3. **Fuel switching**

CCUS is by far the largest investment opportunity and a comparative advantage for Alberta. But the business case for building and operating CCUS projects depends on guaranteed revenue per tonne captured — revenue that comes from selling carbon credits. By committing to ensure a minimum credit price of $130, the MOU makes an important step toward building the business case for widespread deployment of carbon capture in Alberta. But it requires follow-through to strengthen the

TIER market. In the absence of a strong, durable, predictable price signal in TIER, CCUS deployment will continue to stagnate, even with the support of programs like Alberta Carbon Capture Incentive Program (ACCIP) and the federal CCUS investment tax credit (ITC).

Securing credit prices of $130 per tonne is all the more urgent in the wake of the U.S. One Big Beautiful Bill Act (OBBBA), which enhanced the 45Q tax credit for carbon capture. The 45Q offers a US$85 subsidy for each tonne captured; $130 credit prices in Alberta would cement the province's competitive edge for attracting carbon capture investment.

Figure: Carbon credit prices of $130 to $150 could drive $90 billion of capital investment and 70 megatonnes of annual emissions reductions (after CCUS ITC and ACCIP applied)



Right now, that $90 billion worth of capital investment and 70 megatonnes in annual emissions reductions are hypothetical. To turn potential into profit, prosperity, and a decarbonization breakthrough, both Alberta and the federal government must take several important steps leading up to the conclusion of an agreement on TIER by April 1, 2026.

Clean Prosperity recommends that the Government of Alberta and the federal government work together to:

1. Finalize TIER market design rules to achieve a minimum effective credit price of $130 per tonne, including a timeline for achieving this price.

Establishing a credit price trajectory as soon as possible is required to cement Canada's competitive advantage and unlock tens of billions of dollars worth of shovel-ready low-carbon projects, including Pathways Phase 1. The MOU states that this project will be built and commence operations in a staged manner beginning in 2027, which adds to the urgency of finalizing new rules for TIER.

Carbon credit prices are what matter most to project proponents and investors, not the headline carbon price. Higher credit prices are the province's most efficient tool to unlock new investment dollars while reducing emissions.

Widespread deployment of CCUS in Alberta requires credit prices to rise in value and retain their value over the long term. TIER credit prices have declined steadily since 2023 and traded below $20 per tonne as of November 2025. Reversing this trend as soon as possible, and ideally achieving $130 per tonne by 2030, can get low-carbon projects going faster.

2. Implement the financial mechanism outlined in the MOU in the form of joint carbon contracts for difference (CCfDs).

These CCfDs should be broad-based and backstopped by both the Government of Alberta and the Government of Canada to ensure that both parties maintain their commitments on TIER, and to provide near-term certainty for industry.

CCfDs are the most powerful tool available to governments to provide the certainty needed to make TIER credits bankable for project proponents and unlock low-carbon investments in the near term. These contracts should be broad-based and jointly backstopped by the Alberta and federal governments.

Importantly, both governments can structure these contracts in ways that create little or no direct fiscal cost and avoid inflating deficits, while still complying with Public Sector Accounting Standards.

Clean Prosperity recommends that the Government of Alberta:

3. Make the Alberta Carbon Capture Incentive Program (ACCIP) as simple and bankable as possible by revising its payout structure for CCUS projects.

In the MOU, Alberta affirmed its support for ACCIP and committed to expanding this program to support the Pathways project.

ACCIP is a grant of 12% for new eligible CCUS capital costs, paid in three installments over three years after year one of operations. Altering the payout structure so proponents can claim eligible expenditures earlier, in the year they are incurred, would significantly increase the program's value to proponents. The addition of a recovery mechanism could ensure that grant funding would be returned if a project is shelved.

ACCIP could also be redesigned to reduce interactions with other policies that are undermining its effectiveness (e.g. the cost-based royalty payout system for oil sands facilities offsets some of ACCIP's value).

Clean Prosperity recommends that the federal government:

4. Lift the CCUS ITC's exclusion of enhanced oil recovery (EOR), but only for capture and transport equipment, and at a reduced rate.

In the MOU, the federal government has committed to extend federal ITCs to encourage large-scale CCUS investments, including Pathways and EOR. Clean Prosperity recommends that EOR projects be able to claim the CCUS ITC at a reduced rate (e.g. half the rates offered for capture and transport for other eligible uses).

Because most EOR is already profitable on its own, we recommend lifting the eligibility exemption for capture and transport costs only, recognizing that these investments will contribute to the development of learning curves and shared infrastructure that can reduce costs for future CCUS projects. Strong recovery mechanisms already found in the CCUS ITC would need to be expanded to ensure additionality and eliminate free-riding.

The development of "plug-and-play" CO_2 transportation infrastructure and storage sites across Alberta is a key enabling condition for carbon capture to scale. Large EOR projects can serve as anchors for CCUS infrastructure and, in the presence of strong carbon markets, can accelerate scaling.

5. Finalize the Clean Electricity ITC to encourage deployment of low-carbon electricity.

Carbon capture is essential for reducing industrial emissions, but it must be complemented with other pathways, like electrification.

Given the emissions intensity of Alberta's grid, firms switching from natural gas to electricity from the provincial grid would increase overall emissions. Our modelling finds that reducing grid intensity by two-thirds could result in 6.3 $MtCO_2e$ of annual emissions reductions from electrification across five sectors, reflecting both scope 1 emissions reductions at facilities undertaking electrification and additional scope 2 emissions from electricity generation.

The 2025 federal budget reaffirmed the government's intention to legislate the Clean Electricity ITC. It should be finalized as soon as possible.

With the right combination of reforms, Alberta can translate the MOU into robust and durable economic growth. The province can unlock projects with as few public dollars as possible, build future-oriented industrial capacity, and become a global leader in both low-carbon and conventional energy.

Introduction: Marginal abatement cost

In the memorandum of understanding (MOU) signed with the federal government in November 2025, Alberta committed to strengthening its Technology Innovation and Emissions Reduction (TIER) carbon market to ensure a minimum effective credit price of $130/tonne. This report uses marginal abatement cost (MAC) curves with project finance modelling to identify cost-effective technology pathways for large low-carbon projects in Alberta, and analyzes the required credit prices to unlock these technologies. Our MAC curves show **three key technology pathways: 1) efficiency; 2) carbon capture, utilization, and storage (CCUS); and 3) low-carbon fuel switching.**

How to read and interpret MAC curves

MAC curves estimate the cost and emissions-reduction potential of different technologies, expressed as dollars per tonne of carbon dioxide equivalent (CO_2e) reduced or CO_2 captured. The charts in this report are a visual ranking of technologies, sequenced in order of cost effectiveness (most cost-effective options on the far left; least cost-effective options on the far right). The MAC at a specific point on a chart corresponds to the breakeven carbon credit price needed for a specific technology investment to become economically viable.

How MAC curves work:

- The **x-axis** represents **total potential emissions reductions in megatonnes of CO_2e** ($MtCO_2e$) and shows the full range of abatement technology options, including some pathways that are mutually exclusive (e.g. fuel switching could include blue or green hydrogen but likely not both). As a result, the total emissions reductions shown across the x-axis are in some cases greater than the sector's emissions. In reality, not all technology options would be necessary at a single site.
- The **y-axis** shows the **cost per tonne reduced.** Negative numbers mean the measure generates net savings.
- Each bar represents a specific technology for a specific sector. The bar's **width** shows the total possible annual emissions reductions; the **height** shows its cost per tonne.
- We incorporate technology costs and costs associated with financing and operating the emissions-reduction project. We assume a 10% weighted average cost of capital (WACC).

What a MAC curve does not show:

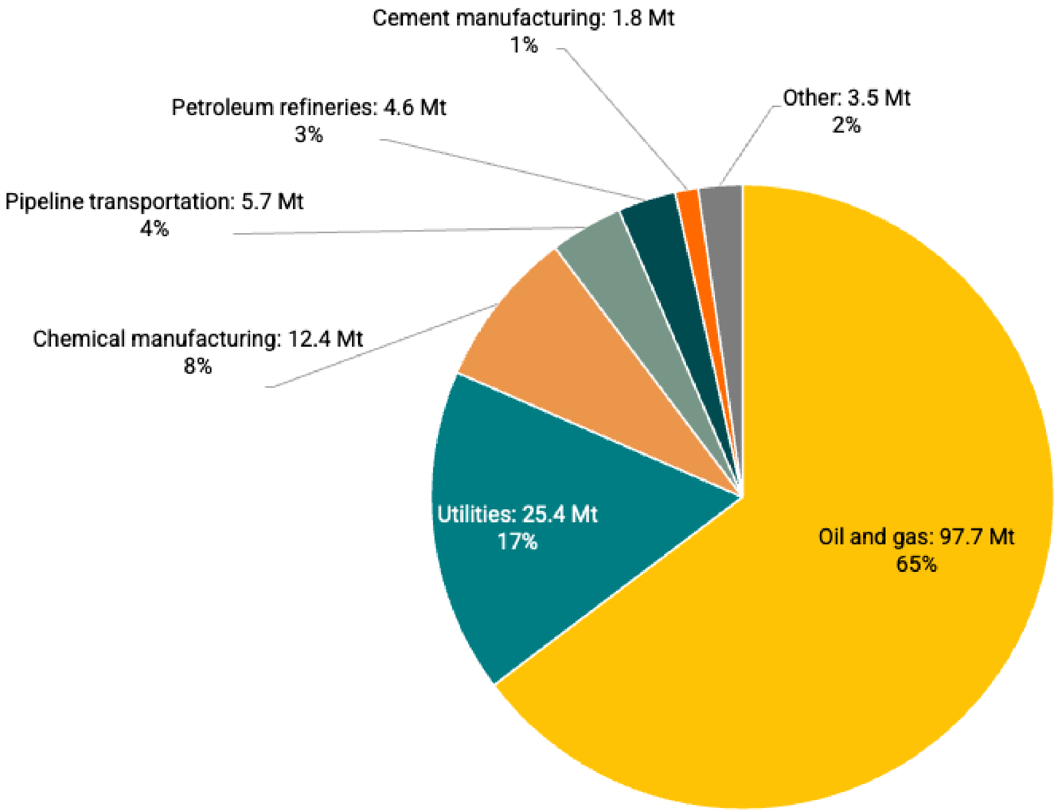
- Ideal sequencing or interactions between technologies (e.g. fuel switching to hydrogen can reduce the total volume of emissions that could be captured through CCUS). Abating emissions in one slice of the MAC curve will affect the sequencing and scale of abatement for other slices.
- Effects of infrastructure bottlenecks or policy uncertainty.
- Factors such as facility age, access to shared infrastructure required for abatement (e.g. pipelines for transport of captured carbon) or first-mover costs.

Carbon capture is a comparative advantage for Alberta with significant investment opportunities across the province's largest industrial sectors. Efficiency offers quick wins with diminishing returns. Fuel switching is largely limited by fuel costs and the emissions intensity of Alberta's grid and shares some obstacles in common with CCUS: retrofits are costly, common infrastructure is limited (e.g. distribution and transportation), and low-carbon fuels like hydrogen and renewable natural gas (RNG) are not available at the scale required.

We analyze each technology solution across our five sectors:

1. **Oil and gas extraction** (666 facilities)[1]
2. **Chemical manufacturing** (24)
3. **Pipeline transportation** (5)
4. **Petroleum refineries** (5)
5. **Cement manufacturing** (2)

Figure 1: Annual emissions from TIER regulated sectors in (2023, $MtCO_2e$)[2]



[1] Oil and gas extraction facility count is based on the number of facilities that report to the federal Greenhouse Gas Reporting Program (GHGRP). This number is larger than the number of regulated facilities under Alberta's TIER program due to aggregation of facilities in companies' reports to the GHGRP.

[2] Based on 2023 emissions from regulated sectors reported in the GHGRP.

These five sectors represent 81% of the emissions covered by the TIER market,[3] the majority of the province's regulated emissions[4] and over a quarter of its GDP.[5]

We generate MAC curves for each sector, with the exception of utilities.[6] The curves are based on in-house project finance and MAC modelling, informed by real-world case studies and consultation with experts, industry, and policymakers. We incorporate a 10% weighted average cost of capital (WACC) and the CCUS investment tax credit (ITC), and grants like the Alberta Carbon Capture Incentive Program (ACCIP).

Alberta's low-carbon policy landscape

Alberta's Technology Innovation and Emissions Reduction (TIER) Regulation is a carbon market covering industrial facilities in Alberta that emit over 100,000 tonnes of CO_2 equivalent (CO_2e) per year. TIER is by far the largest standalone carbon market in Canada, with over 50 million active carbon credits. Emitters can generate several different types of carbon credits based on their emissions performance relative to an assigned benchmark (see Table 2 in the Appendix for a full list of credit types and Table 3 for a description of benchmarks). Several firms and facilities covered by the TIER market have also signed carbon contracts for difference (CCfDs) with the Canada Growth Fund, which guarantees the value of the credits they generate regardless of the TIER market price (see box below).

In September 2025 the Government of Alberta added a direct investment compliance option to TIER that enables facilities to satisfy a portion of their compliance obligations with eligible capital

[3] Based on 2023 emissions from regulated sectors reported in the GHGRP.

[4] Scope 1 emissions. In 2023, 90% of regulated emissions came from facilities mandatorily covered under the program. The remaining 10% came from opt-in facilities, most of which are expected to leave the program through new opt-out provisions announced in September 2025.

[5] Approximately 27% of the province's GDP in 2021.

[6] We do not generate a MAC curve for the utilities sector due to its unique systems-level emissions profile. See the Utilities section for a more detailed sectoral analysis.

expenditures, rather than credits. Details remain in development as of December 2025, but this change had a marked effect on market sentiment. The price of credits in the TIER marketplace fell sharply, to as low as $15/tonne, from a high of $55/tonne in 2023.

The incentives created by TIER are supported by several other policies. The Alberta Petrochemicals Investment Program and the Alberta Carbon Capture Incentive Program (ACCIP) are both grants worth 12% of eligible capital and equipment expenses. Low-carbon projects in Alberta can also now access four federal investment tax credits (ITCs) for: hydrogen (starting at 15-40% of eligible capital expenditures), carbon capture (50%), carbon transportation and storage (37.5%), direct air capture (60%), clean technology (30%), and clean technology manufacturing (30%). The Clean Electricity ITC (15%) is not yet legislated; of the listed ITCs, it is the only one that can be claimed by non-taxable entities like Crown corporations and Indigenous communities. Projects that claim TIER credits can simultaneously claim credits for the same activities via the federal Clean Fuel Regulations (CFR).

What are carbon contracts for difference?

Carbon contracts for difference (CCfDs), also known as carbon contracts, are agreements between federal or provincial governments and low-carbon project proponents. The contracts offer a government guarantee on the future value of carbon credits generated by a low-carbon project in a carbon market, which eliminates significant sources of risk and uncertainty for the proponent. The government guarantees a specific credit price for a specific period of time (typically 10 to 15 years) with payment obligations settled on a regular basis.

There are a number of ways to structure CCfDs. The key differentiator is who ultimately retains control of the credits after the contract is settled.

- With offtake agreements, the government commits to directly purchasing carbon credits from the proponent at an agreed-upon price.
- With top-up CCfDs, parties set a “strike price” for carbon. If the carbon price exceeds the strike price at the time of settlement, the proponent pays the difference to the government. If the carbon price falls below the strike price, the government pays the difference. In this structure cash, rather than credits, changes hands. The proponent keeps the carbon credits and so retains the incentive to sell its credits in the open market at the best possible price.
- Other designs, such as a guaranteed price floor for credits, are possible as well.

A key consideration in either an offtake or top-up CCfD is how to set the strike price. To date, the Canada Growth Fund has signed a number of bespoke CCfDs where the strike price and other terms were negotiated with a particular project proponent. Clean Prosperity favours a different CCfD design — a standardized contract, jointly backstopped by the Alberta and federal governments, with a standard strike price and standard terms that can be accessed by any large emitter that participates in TIER.

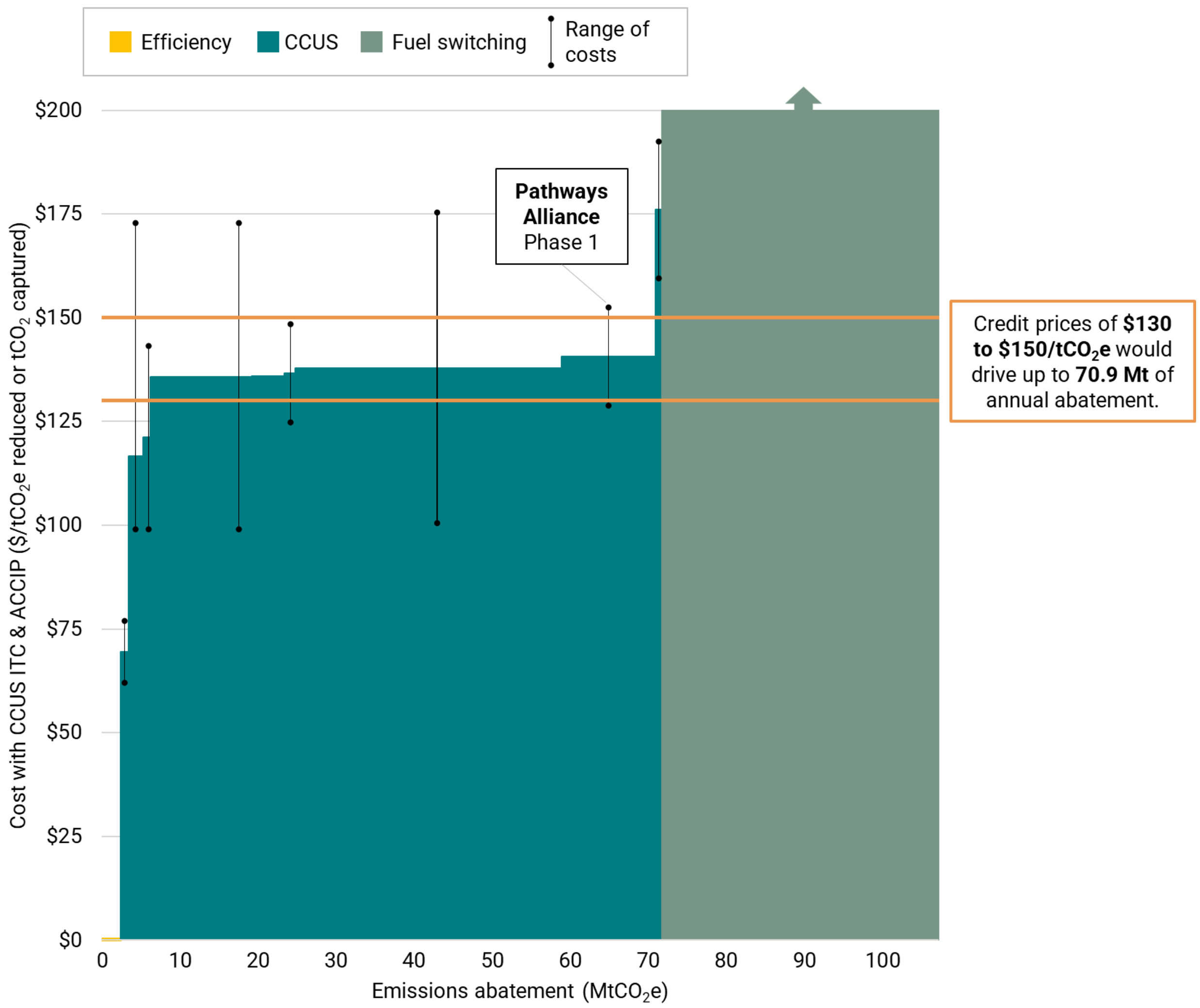
Regardless of contract type, governments can avoid payouts against CCfDs by making the necessary adjustments to their carbon pricing systems. As long as the government ensures that carbon-credit markets operate efficiently with a clear trajectory for credit prices, CCfDs need never be exercised.

Alberta’s three technology pathways for reducing emissions

Using a single unit (dollars per tonne of carbon dioxide equivalent reduced or carbon dioxide captured), we analyze MAC curves across three technology pathways. As we note above, some abatement opportunities shown in our MAC curves are mutually exclusive (e.g. blue and green hydrogen would abate the same emissions sources, but blue is cheaper on a per-tonne basis).

Figure 2 shows a consolidated MAC curve for the five sectors of Alberta’s industrial economy analyzed in this report. This figure differs from other MAC curves in the report in that we omit mutually exclusive pathways and show only the most cost-effective abatement options inclusive of available ITCs. Figure 2 highlights the carbon credit price range that would be needed to incentivize emissions abatement.

Figure 2: Marginal abatement cost curve for five sectors of Alberta's industrial economy



MAC curves are tools to help evaluate and prioritize low-carbon technology investments. In addition to isolating only the most cost-effective pathway for each tonne of emissions abatement, Figure 2 excludes abatement actions already taken (e.g. the majority of emissions-abating efficiencies) and projects already underway (e.g. CCUS at Air Products' Edmonton hydrogen facility, North West Redwater's Sturgeon refinery, and Shell's Scotford refinery).[7]

We find that **CCUS represents the largest opportunity for meaningful, cost-effective emissions reductions across five sectors.** Fuel switching has comparatively higher costs. Efficiencies offer quick wins but have already been widely adopted.

[7] 40% capture at Shell's Scotford refinery.

All three technology pathways entail new, additional investments relative to the status quo. Carbon credits, ITCs, and complementary policies play a central role in bridging the revenue-certainty gap for these investments. **High-value carbon credits are the single most important incentive.** Many projects can also of course be driven to or away from final investment decisions for reasons unrelated to carbon markets, such as the broader regulatory environment or global commodity prices.

Most CCUS projects become economically viable when carbon credits trade in the range of $130 to $150 per tonne. At a price of $80 to $100 per tonne of CO_2e, our modelling shows that Alberta can unlock $5.6 billion of capital expenditures and 3.4 megatonnes (Mt) of profitable annual reductions. Between $130 to $150 per tonne, we see $90.9 billion of capital expenditures and 70.9 Mt of emissions reductions — the overwhelming majority of it in CCUS. To unlock these investments, higher carbon credit prices are what matter most to project proponents and investors, not a higher headline carbon price.

A high headline price is meaningless without higher credit prices. TIER credit prices have declined steadily since 2023 and traded below $20 per tonne as of November 2025. With credit prices this low, the $95 per tonne headline price has a negligible effect on investment decisions and carbon markets will not drive CCUS deployment or fuel switching.

Efficiency

Efficiency measures reduce fuel use, which not only reduces emissions but also improves operational performance. Most of our efficiency pathways are thermal or energy efficiency improvements.[8] Many offer low marginal abatement costs or net savings but deliver small returns and emissions reductions compared to other technologies. As a result, many facilities have already adopted these measures to capture early, low-cost abatement opportunities. Efficiency pathways identified in this report include alternative production processes, machinery upgrades, and waste heat recovery (WHR) systems. Examples include alternative steam-assisted gravity drainage (SAGD) extraction technologies in in-situ oil sands extraction; and kiln upgrades with preheaters and precalciners in cement manufacturing.

Including pathways already implemented and additional, our MAC analysis shows that efficiency measures cost between -$44/t$CO_2$e and $76/t$CO_2$e reduced.

Carbon capture, utilization, and storage (CCUS)

Carbon capture is the process of separating CO_2 from combustion or process emissions streams. Capture can be pre-combustion (scrubbing CO_2 from feedstocks before combustion) or post-combustion (scrubbing CO_2 from flue gas using solvents). The costs depicted in our MAC curve

[8] One exception is the use of supplementary cementitious materials in cement manufacturing, which improves material efficiency.

include capture, compression, transport, and sequestration.[9] These processes are energy-intensive. We assume power for CCUS comes directly from Alberta's grid, which increases scope 2 emissions.[10]

Presently, the most common form of utilization for carbon is **enhanced oil recovery** (EOR).[11] The IEA estimates that oil and gas operations can use EOR to recover 1.5 to 3 barrels per tonne of CO_2 injected. The increased production can extend the life of existing oil wells by years or even decades. CO_2-EOR has lifecycle emissions intensity up to 37% lower than oil from conventional production. For comparison, we estimate upstream CCUS would reduce the lifecycle emissions intensity of conventional oil production by 6% to 12% relative to conventional production.[12]

Geologic sequestration remains the most prominent storage option for captured carbon.[13] Alberta also has abundant geologic storage space, estimated at 79,000 $MtCO_2$. There are several other end uses for captured CO_2, including chemical production, mineralization, and building materials. Alberta also has significant CCUS transportation infrastructure for sequestration, like the Alberta Carbon Trunk Line (ACTL), with an annual capacity of 14.6 $MtCO_2$.

Across our MAC curve, with the CCUS ITC and ACCIP applied, we show a weighted average cost of $137/$tCO_2$ for over 69 $MtCO_2$ of annual capture. Different fuels, combustion types, and facilities' balance of plants can result in widely varying capture costs.

Direct air capture (DAC) is a pathway that removes CO_2 from the atmosphere, in contrast to point-source capture. A common pathway in energy-economy modelling, commercial DAC is not yet available at scale and is significantly more expensive than point-source capture. Given these constraints, we exclude it and other carbon dioxide removal technologies from our analysis.

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[9] We assume an average transport distance of 161 km. Many projects in Alberta are closer to shared infrastructure than this (e.g. Alberta's Industrial Heartland) and will have lower transport costs as a result. Projects that are remote and/or require more bespoke infrastructure (e.g. Pathways Phase 1) will have higher-than-average transport costs.

[10] Some proponents co-deploy combined heat and power with capture units; gross emissions rise prior to capture, but net system emissions can fall as on-site electricity replaces more carbon-intensive grid supply.

[11] EOR is a set of extraction techniques for oil reservoirs after exhaustion of primary production and secondary recovery. It can pair with geologic sequestration, so a significant portion of injected CO_2 remains stored underground. EOR mobilizes residual oil by changing fluid properties, rock–fluid interactions, or sweep efficiency. Common EOR types include thermal methods, chemical floods, solvent-based approaches, and gas/foam methods, including CO_2-EOR. CO_2-EOR uses CO_2 as a mix-and-push agent, blending into oil to make it thinner and easier to move, pushing the oil toward producing wells.

[12] Estimates for Alberta Innovates found 10-17% of lifecycle or "well-to-wheel" emissions across oil sands pathways are upstream emissions from production. Other peer-reviewed studies consistently find upstream production contributes 10-20% of lifecycle GHG emissions, with variance based on extraction method and whether upgrading is included. Our analysis estimates that upstream CCS would reduce emissions by about 58% from upstream conventional oil and gas extraction.

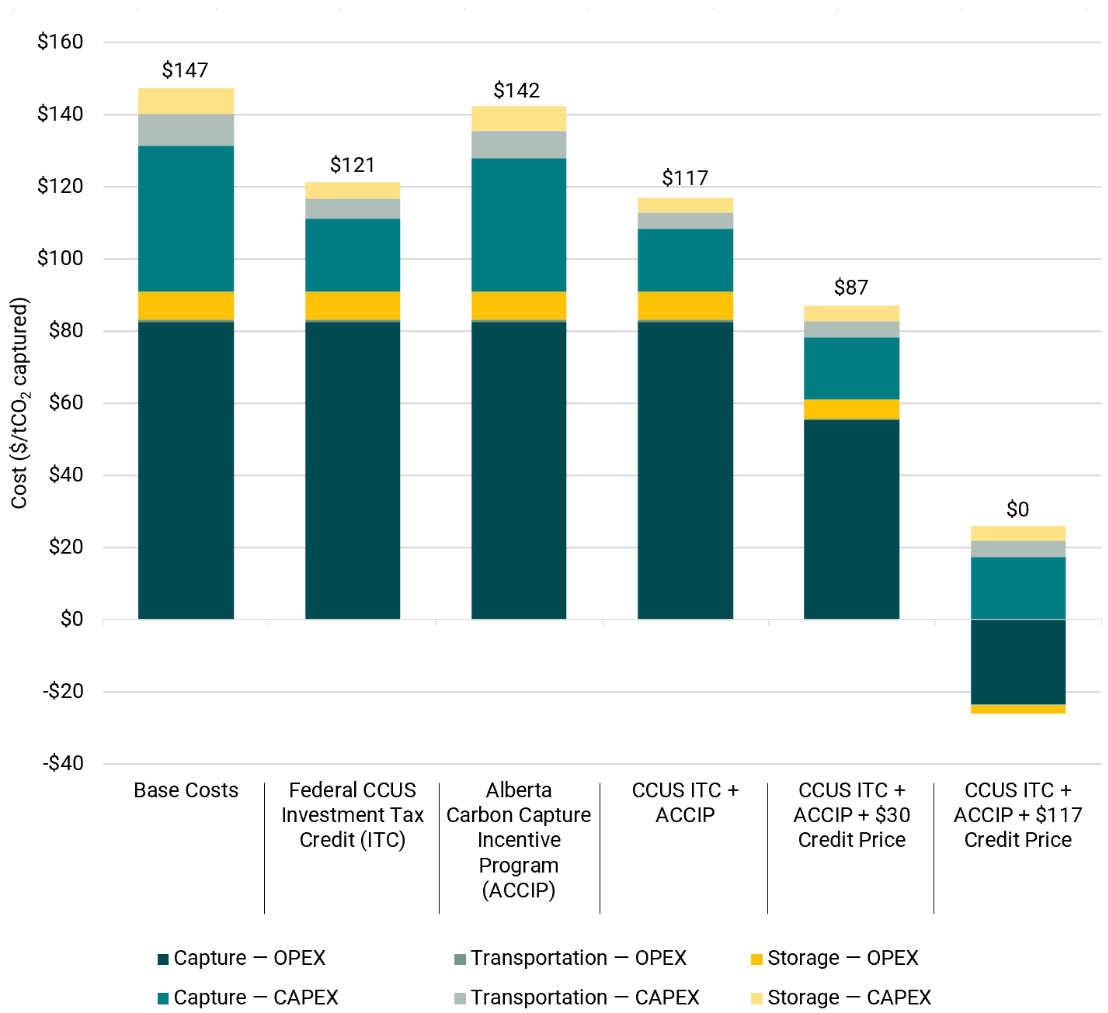
[13] Storage reservoirs include: saline aquifers, depleted oil and gas fields, and basalt formations. Storage faces many challenges including permitting and long-term liability.

The economics of CCUS in Alberta

Since operations began in 2015, Shell's Quest carbon capture project for hydrogen production has become a relevant cost benchmark for CCUS in Alberta. It offers a real-world anchor for comparison with CCUS project cost estimates — albeit that Quest operates on an emissions stream with higher CO_2 concentrations than would be found in some other applications, like upstream oil and gas.

To illustrate the importance of different policy incentives, Figure 3 breaks out Quest's reported costs and shows the impact of these incentives if Quest was built today, including existing ITCs and credit revenues from programs like TIER or the Clean Fuel Regulations. We calculate $117 as the breakeven credit price. To make these calculations, we use base costs from public reporting, indexed to inflation, offset by publicly reported 20% technology cost reductions since Quest's construction. Capture accounts for the majority of costs in this case study. Costs vary based on a project's location and access to supporting infrastructure. Transportation and storage costs for additional capture projects may be smaller than the first project in a region.

Figure 3: CCUS cost estimates for Quest with various policy supports ($/tCO$_2$ captured)



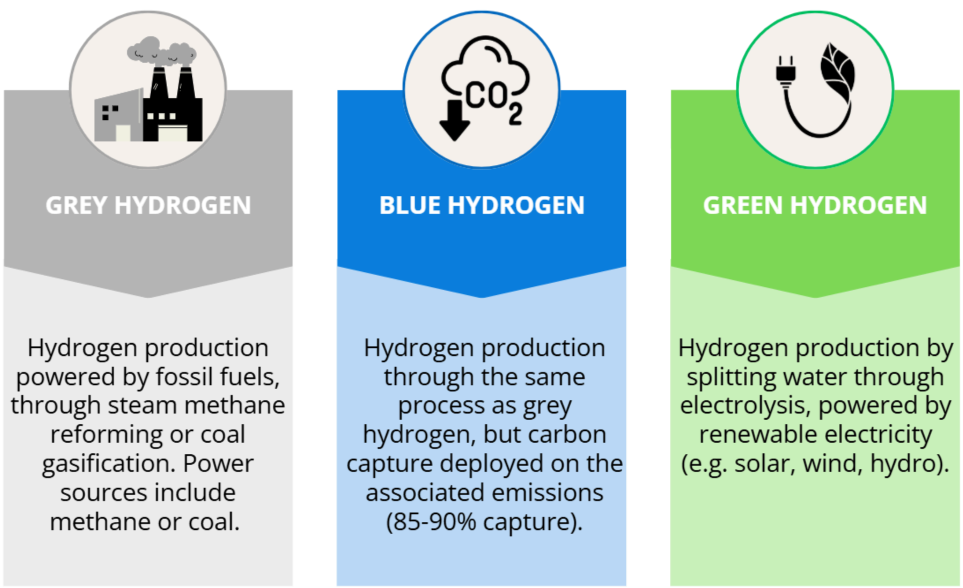
Fuel switching

Fuel switching typically refers to the displacement of fossil fuels with lower-emitting fuels or electricity. Across all sectors, our calculations assume the displaced fuel is natural gas. We consider numerous low-carbon fuels for fuel switching, including blue and green hydrogen (see box below), biofuels like renewable natural gas (RNG), and electrification. Emissions from electricity are considered in the electrification of equipment. We estimate that over 35 $MtCO_2e$ in annual emissions reductions can be achieved through fuel switching, with a wide cost range of \$361/tCO_2e to \$1,070/tCO_2e.

Types of hydrogen

Fuel switching to hydrogen is possible across multiple sectors. There are three primary pathways of hydrogen fuel production, denoted via colour coding (see Figure 4). Grey hydrogen has the highest carbon intensity, green the lowest. There are many emerging types of low-carbon hydrogen production; blue and green hydrogen are the most common and technologically viable. This report focuses on fuel switching to blue and green hydrogen. On-site hydrogen combustion is non-emitting regardless of its source and will not affect a facility's scope 1 emissions.

Figure 4: Hydrogen production processes



Sector pathways

We generate individual MAC curves for five sectors, covering scope 1 emissions reduction technologies. **There are four broad categories of scope 1 industrial emissions.**

- **Combustion emissions:** emissions released from burning fuels (e.g. natural gas) to produce energy for on-site processes, such as electricity or steam generation.
- **Process emissions:** emissions resulting from chemical reactions or physical processes.
- **Flaring and venting:** flaring is the controlled burning of excess fuel or materials. Venting is the intentional release of unburned gases into the atmosphere (typically methane).
- **Fugitive emissions:** unintentional release of gases from equipment or pipelines (e.g. leaks from valves or seals).

Each emissions source presents distinct technological considerations with respect to abatement. For instance, process emissions typically have a higher concentration of CO_2 compared to combustion emissions, which enables lower marginal costs per tonne of CO_2 captured. We separate CCUS for process and combustion streams for most sectors to account for differential cost estimates across these technologies.

MACs are inclusive of capital costs (including new equipment, retrofits, and storage for alternative fuels), operating costs (including fuel and electricity costs), and net savings (including cost reductions from displaced natural gas). Costs incorporate the savings from application of the federal CCUS ITC and ACCIP.

Across the sector-specific MAC curves in this section, the x-axis displays the full range of assessed technology options. While some technologies are mutually exclusive or already implemented, we include all possible pathways to compare abatement options (e.g. green hydrogen and blue hydrogen; post-combustion carbon capture and oxyfuel carbon capture in cement manufacturing).

Where applicable, MAC curves show capital cost reductions enabled by ITCs such as ACCIP and the federal ITCs for CCUS. **For CCUS projects, tax incentives reduce marginal abatement costs by 13% on average, pushing the vast majority of CCUS projects between \$130 and \$150/tCO_2 captured.**

Technical Assumptions

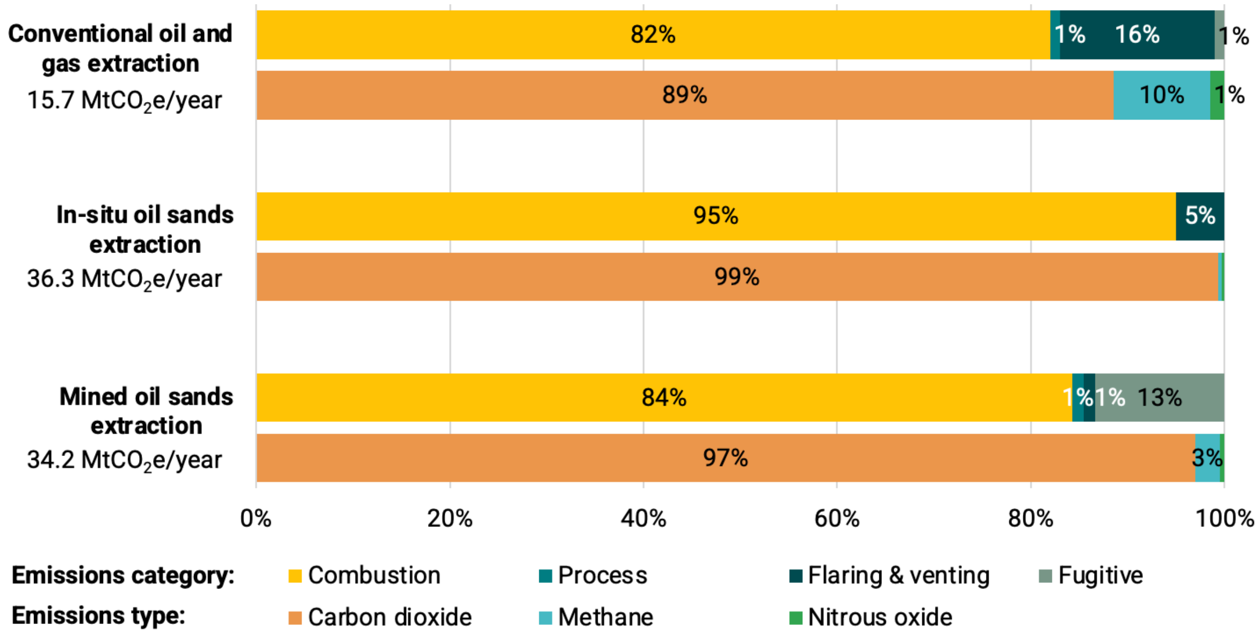
- **Cost ranges**: Each technology pathway and project has sources of uncertainty (see Table 1 in the Appendix). As a result, there are error bars associated with project costs, including capital expenditures, pricing of inputs and labour, and savings on displaced fuels. Our MAC curves display our median cost estimates, with the vertical dotted lines representing our full range of estimates for each pathway.
- **Financing**: 10% WACC over the project life. We assume debt financing on 50% of capital costs.[14]
- **Project life**: 20 years.
- **Costs**: All costs are expressed in 2025 Canadian dollars, unless otherwise specified.
- **Tax credits**: CCUS ITC and ACCIP applications assume all eligible capital expenses claim maximum tax credit rates and meet labour and apprenticeship requirements.
- **Emissions baselines**: Average annual regulated emissions are used for each sector's emissions reduction potential. For a typical facility, we use average annual facility emissions and assume standard operations.

[14] Most of the abatement projects in our MAC curves are, at this point, hypothetical. To account for the fact that the Pathways Alliance Phase 1 CCS project is a real project, we have applied different assumptions to this project, based on consultation with stakeholders. We apply a debt-equity split of 75:25 to the capture component and 100% debt financing for the pipeline component over a 20-year project life.

Oil and gas extraction

Our analysis covers all three oil extraction sub-sectors: conventional oil and gas extraction, in-situ oil sands extraction, and mined oil sands extraction. The emissions profiles are different, and each sub-sector has unique activities and opportunities for investment in emissions abatement.

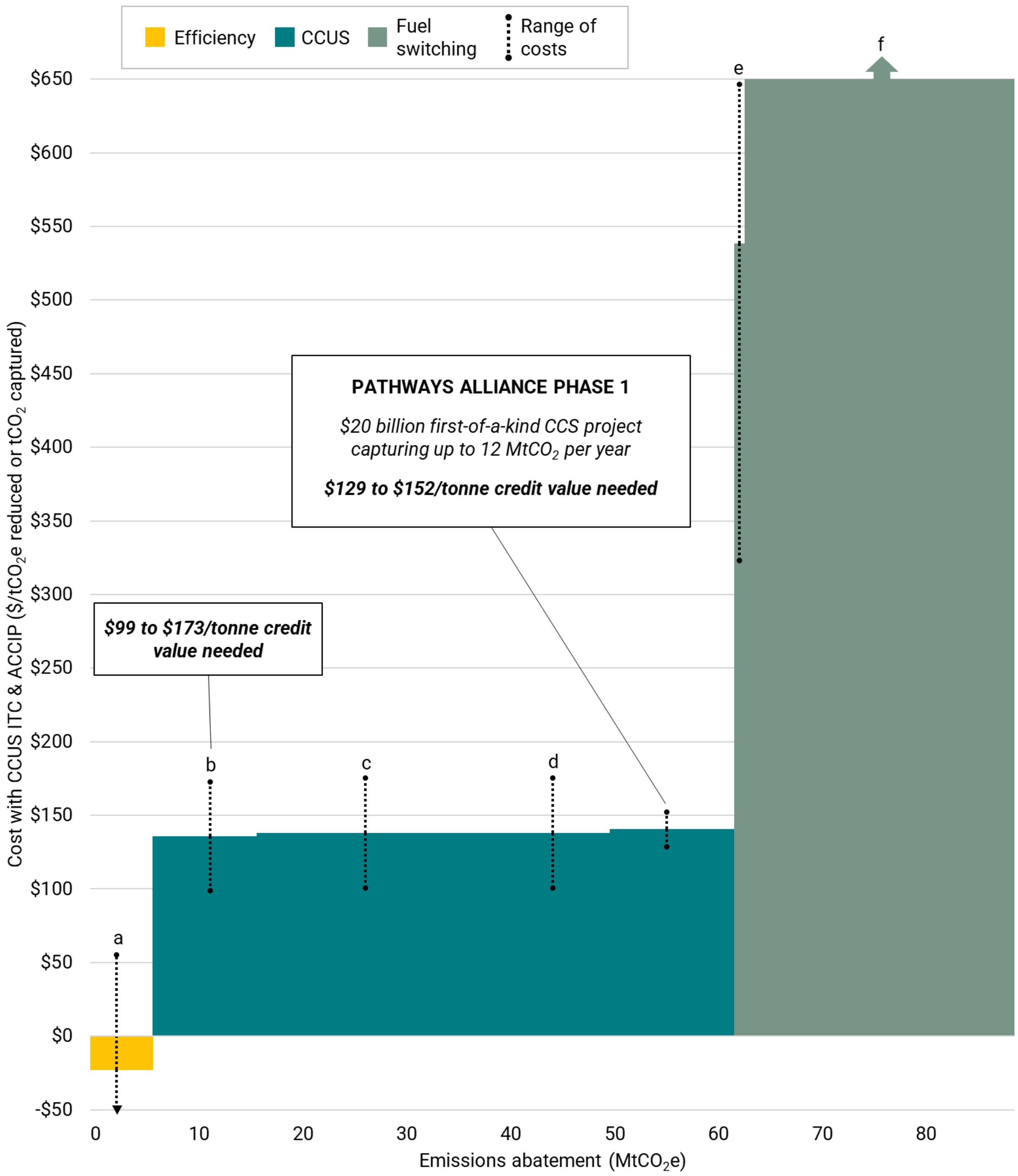
Figure 5: Emissions profile for oil and gas extraction[15]



Efficiency improvements offer the most cost-effective abatement opportunities for in-situ oil sands extraction, with potential for cost savings through use of alternative steam-assisted gravity drainage (SAGD) techniques. By reducing the need for steam generation, widespread adoption could reduce total sector emissions by up to 5.2 $MtCO_2e$ per year. However, many operations have already been implemented or piloted, reducing the total additional emissions abatement potential for these technologies.

[15] Emissions sources are derived from averages across 2022 and 2023 GHGRP reports or averages across 2022 and 2023 National Inventory Reports (as applicable). The breakdown of emission types throughout the analysis is based on reported 2023 GHGRP data for the sector.

Figure 6: Marginal abatement cost curve for oil and gas extraction in Alberta



a. In-situ oil sands extraction – alternative SAGD-extraction technologies (steam and gas push)
b. Oil and gas extraction (except oil sands) – CCS for combustion emissions
c. In-situ oil sands extraction (w/o Pathways) – CCS for combustion emissions
d. Mined oil sands extraction (w/o Pathways) – CCS for combustion emissions
e. Oil and gas extraction (except oil sands) – electrification of turbines
f. In-situ oil sands extraction – small modular reactors (100% swap)

CCUS for combustion emissions is the most significant mitigation pathway across all three sub-sectors. With incentives, we estimate that a majority of emissions in the sector can be captured at a cost of $138/t$CO_2$ but vary across facilities based on site-specific operations.[16] For instance, ACCIP reduces the cost base for pre-payout royalties for oil sands facilities, with varying influence on each individual project.

Phase 1 of the $20-billion Pathways Alliance CCS project is a first-of-a-kind (FOAK) regional system with capture, transport, and storage from scratch. As a result, we estimate a higher median MAC of $168/t$CO_2$ without incentives. This project includes the buildout of significant, system-level shared infrastructure: capture equipment across potentially dozens of sites, plus collector pipelines, a 400-km trunkline, and a central storage hub. This is significantly more complex than the other projects modelled in our MAC curve, which assume standalone capture and transport systems for each facility.

Pathways' custom infrastructure requirements lead to higher costs per tonne. In the MOU, the federal and Alberta governments committed to a tri-lateral agreement with the Pathways project partners by April 2026. The MOU also commits to building the Pathways project and commencing operations in stages between 2027 to 2040. Factoring in the federal CCUS ITC and ACCIP, we estimate that Pathways Phase 1 will have costs in the range of $129 to $152/t$CO_2$ captured. Securing credit prices of $130 per tonne can create a competitive advantage for Alberta in attracting investment in carbon capture over the U.S., which enhanced its 45Q credit for carbon capture in the 2025 One Big Beautiful Bill Act (US$85 per tonne).

Enhanced oil recovery (EOR) is a common alternate end use for captured carbon in oil and gas extraction. Each tonne of CO_2 injected can contribute revenue of $163 before accounting for carbon credit revenue.[17] While there is no difference in the direct emissions reductions associated with sequestering one tonne of CO_2 through CCS versus CO_2-EOR, CO_2-EOR can reduce lifecycle emissions

[16] For example, Entropy's Glacier carbon capture project reports capital expenditures of approximately $127 million to capture 160,000 tCO_2 annually, for a cost of approximately $40/t$CO_2$ captured. Operational costs are assumed negligible, as the system uses waste heat as its energy source.

[17] Estimates as an average of 1.5-3 bbl/tCO_2 injected, AER oil pricing in 2025 and 2034, and 80% netback factor.

intensity of oil by up to 37%, compared to 6% to 12% for upstream CCUS for conventional oil production.[18]

Fuel switching opportunities are limited in oil and gas extraction. Partial electrification of surface equipment is technically feasible in some cases, but the emissions reductions are minimal and costly for conventional oil and gas extraction. In oil sands operations, large-scale electrification faces steeper barriers. Our modelling shows that electrification of equipment would increase provincial emissions based on the current emissions intensity of Alberta's grid.

Several private-sector actors have proposed small modular reactors (SMRs) as a pathway for fuel switching in the oil sands. We estimate decarbonization costs of over \$1,100/tCO_2e reduced, but acknowledge that other benefits and spillover effects may justify the pursuit of SMRs or large nuclear reactors.[19] Aside from partial electrification, fuel switching is not a practical pathway for most low-carbon fuels. Natural gas remains cheap, abundant, and operationally reliable, and the alternatives appear cost prohibitive.

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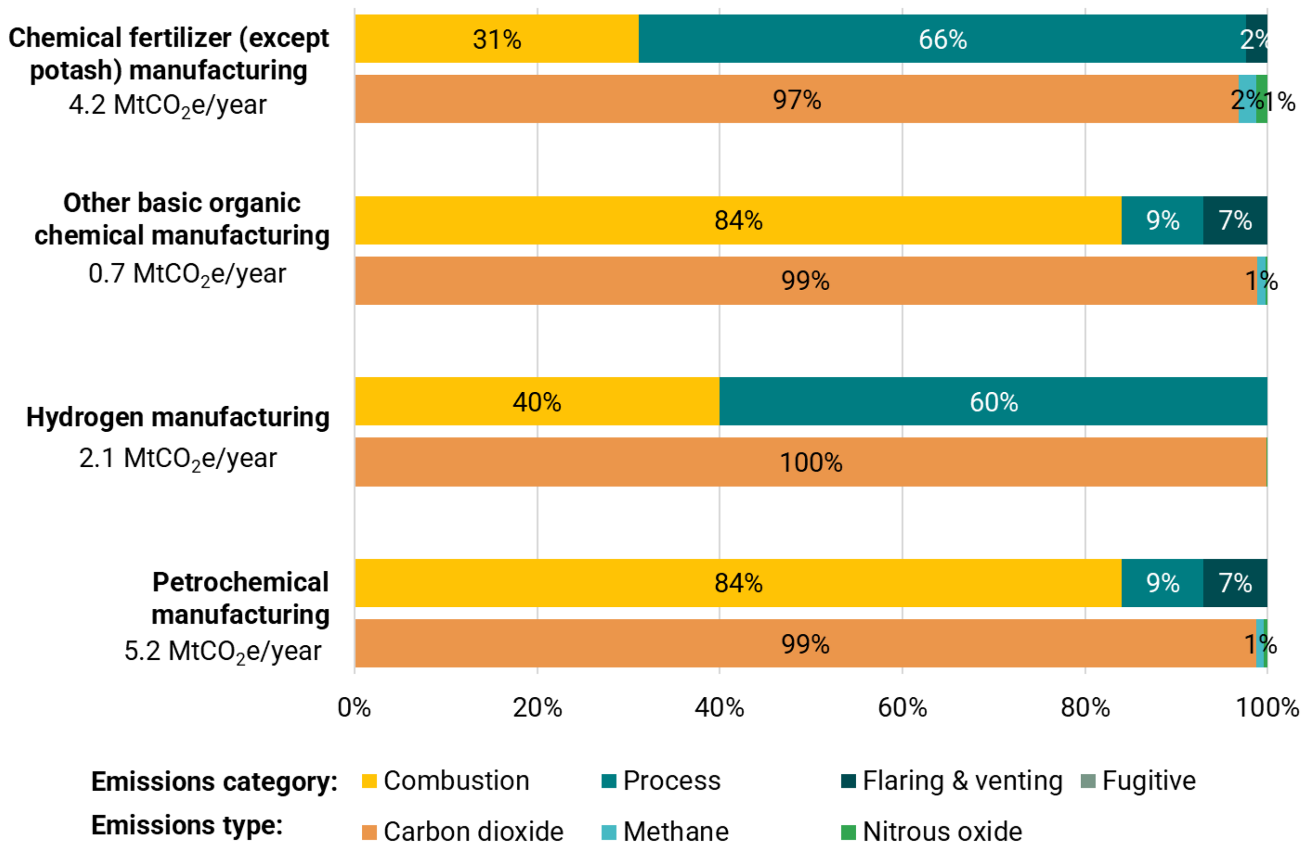
[18] Estimates for Alberta Innovates found that upstream oil sands production contributes 10-17% of lifecycle or "well-to-wheel" emissions. Other assessments consistently find upstream production contributes between 10% to 20% of lifecycle GHG emissions for oil sands, with exact percentages varying by extraction method and whether upgrading is included. We estimate that CCS would reduce upstream emissions by about 58% relative to conventional oil and gas extraction.

[19] This cost estimate assumes any SMR would be built on time and on budget, in a jurisdiction that has no construction experience with nuclear power.

Chemical manufacturing

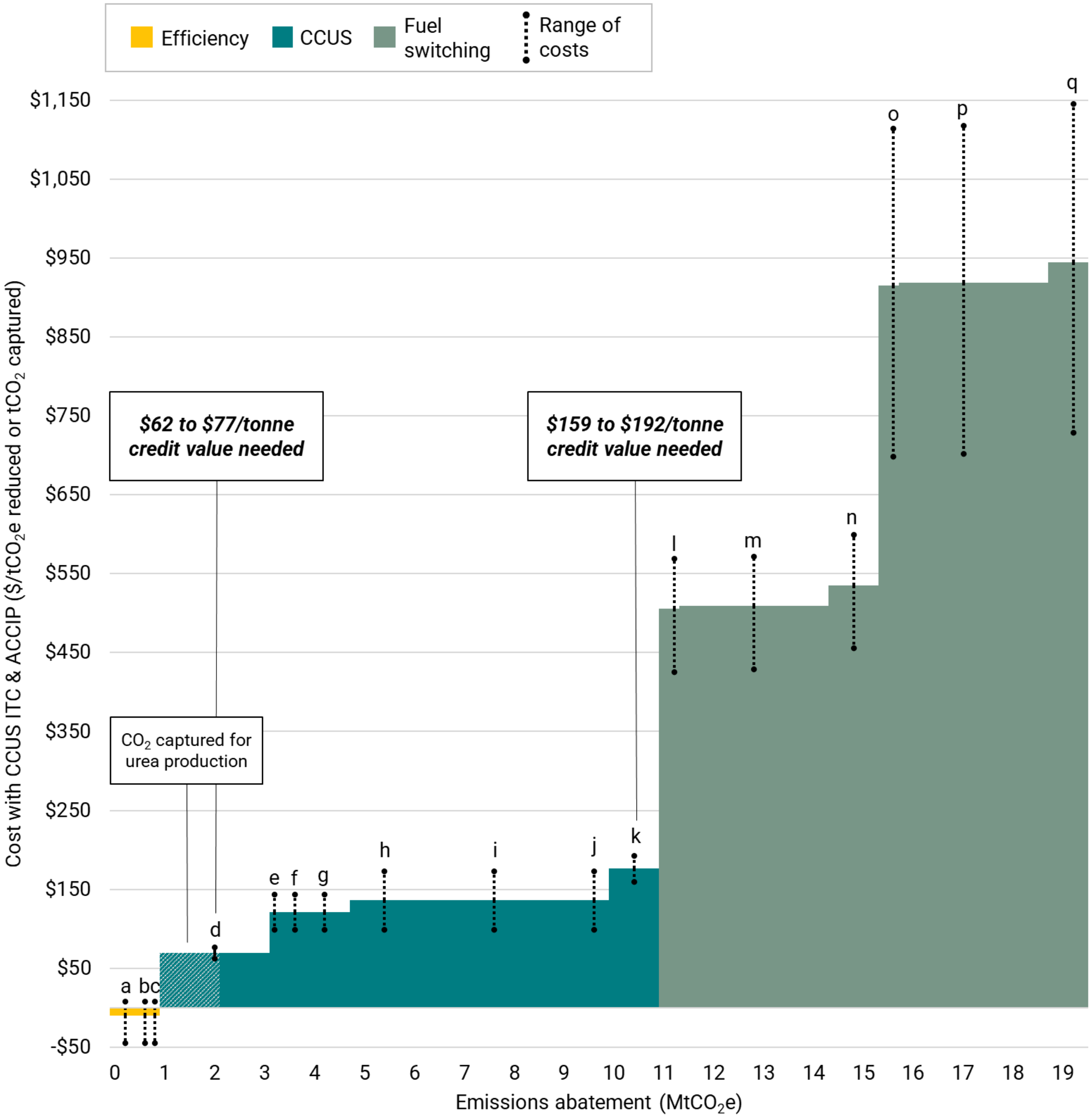
The chemical sector is diverse (as seen in Figure 7). While the industry is comprised of six sub-sectors, the majority of direct emissions in Alberta come from four: petrochemical manufacturing, industrial gas manufacturing (this analysis focuses on hydrogen manufacturing facilities), other basic organic chemical manufacturing, and chemical fertilizer (except potash) manufacturing.

Figure 7: Emissions profile for chemical manufacturing[20]



[20] Emissions sources are derived from industry reports for chemical fertilizer (except potash) manufacturing and hydrogen manufacturing, and from averages across 2022 and 2023 GHGRP reports for petrochemical manufacturing and other basic organic chemical manufacturing.

Figure 8: Marginal abatement cost curve for Alberta's chemical manufacturing sector



a. Petrochemical manufacturing – waste heat recovery systems
b. Chemical fertilizer (except potash) manufacturing – waste heat recovery systems
c. Other basic organic chemical manufacturing –waste heat recovery systems
d. Chemical fertilizer (except potash) manufacturing – CCS for process emissions
e. Other basic organic chemical manufacturing – CCS for process emissions
f. Petrochemical manufacturing – CCS for process emissions
g. Hydrogen manufacturing – CCS for process emissions
h. Other basic organic chemical manufacturing – CCS for combustion emissions
i. Petrochemical manufacturing – CCS for combustion emissions
J. Hydrogen manufacturing – CCS for combustion emissions
k. Chemical fertilizer (except potash) manufacturing – CCS for combustion emissions
l. Other basic organic chemical manufacturing – blue hydrogen (70% swap)
m. Petrochemical manufacturing – blue hydrogen (70% swap)
n. Chemical fertilizer (except potash) manufacturing – blue hydrogen (70% swap)
o. Other basic organic chemical manufacturing – green hydrogen (70% swap)
p. Petrochemical manufacturing – green hydrogen (70% swap)
q. Chemical fertilizer (except potash) manufacturing – Green hydrogen (70% swap)

Carbon capture is the most broadly applicable and investment-ready pathway for chemical manufacturing and offers abatement at half the costs of most potential fuel switching pathways. Many of the sector's emissions originate from continuous, high-temperature processes like steam methane reforming or ammonia production, which produce high-purity CO_2 streams. These point sources are well suited for retrofit with capture systems, often without disrupting core production processes.[21] Pre-combustion capture is a more technically-complex option, which is already being pursued alongside hydrogen fuel switching at Air Products' Canada Net-Zero Hydrogen Energy Complex.

Access to infrastructure for carbon transportation is a site-specific barrier. We calculate that integrated combustion and process capture systems across the four sub-sectors could abate an additional 6.8 $MtCO_2e$ per year.[22] High-purity carbon streams from processes like steam methane reforming or ammonia production further enhance project economics and could drive down costs below our estimate.

Fertilizer Canada identified SMRs as a fuel switching pathway for fertilizer manufacturing. As in the oil and gas extraction sector, SMRs face high capital costs, regulatory uncertainty, and can primarily offset electricity emissions.

Electrification in chemical manufacturing would lead to a net increase in emissions based on the current emissions-intensity of Alberta's electricity grid. For example, our modeling shows that electrification of boilers in petrochemical manufacturing can lead to almost a 36% increase in emissions compared to natural gas. This undermines the effectiveness of electrification as a low-carbon pathway.

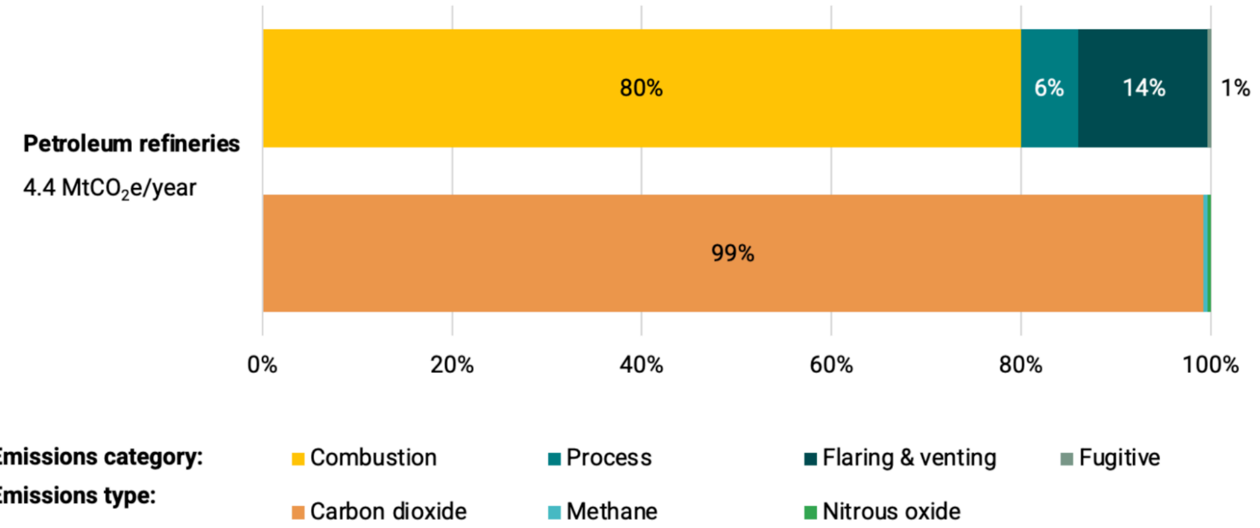
[21] An average of 61% of process emissions in fertilizer manufacturing are captured primarily for use in urea production. This portion may not be available for CCUS, but varies across facilities.
[22] Total excludes Air Products' Edmonton Hydrogen Facility as the project is not additional, and the 61% of process emissions from fertilizer manufacturing that are captured on average for urea production.

Petroleum refineries

There are five refineries in Alberta that together emit 4.4 $MtCO_2e$ per year. The majority of emissions from refineries come from burning fossil fuels to power stationary equipment. The remaining emissions are process-related, mostly from fluid catalytic crackers and steam methane reformers.

In practice, each refinery has unique and complex processes, feedstocks, products, and units, with many emissions sources distributed across a facility. Figure 9 shows the sectoral average in Alberta, but the distribution of process and combustion emissions varies significantly across facilities and contributes to the technical complexity of mitigation options.

Figure 9: Emissions profile for petroleum refining[23]



Alberta's largest refineries — Suncor's Edmonton Refinery and Imperial Oil's Strathcona Refinery — are in close proximity to one another and a broader network of petrochemical, chemical, and energy infrastructure. The regional clustering is an opportunity for coordination on carbon capture, leveraging the new Edmonton Connector on the Alberta Carbon Trunk Line (ACTL).

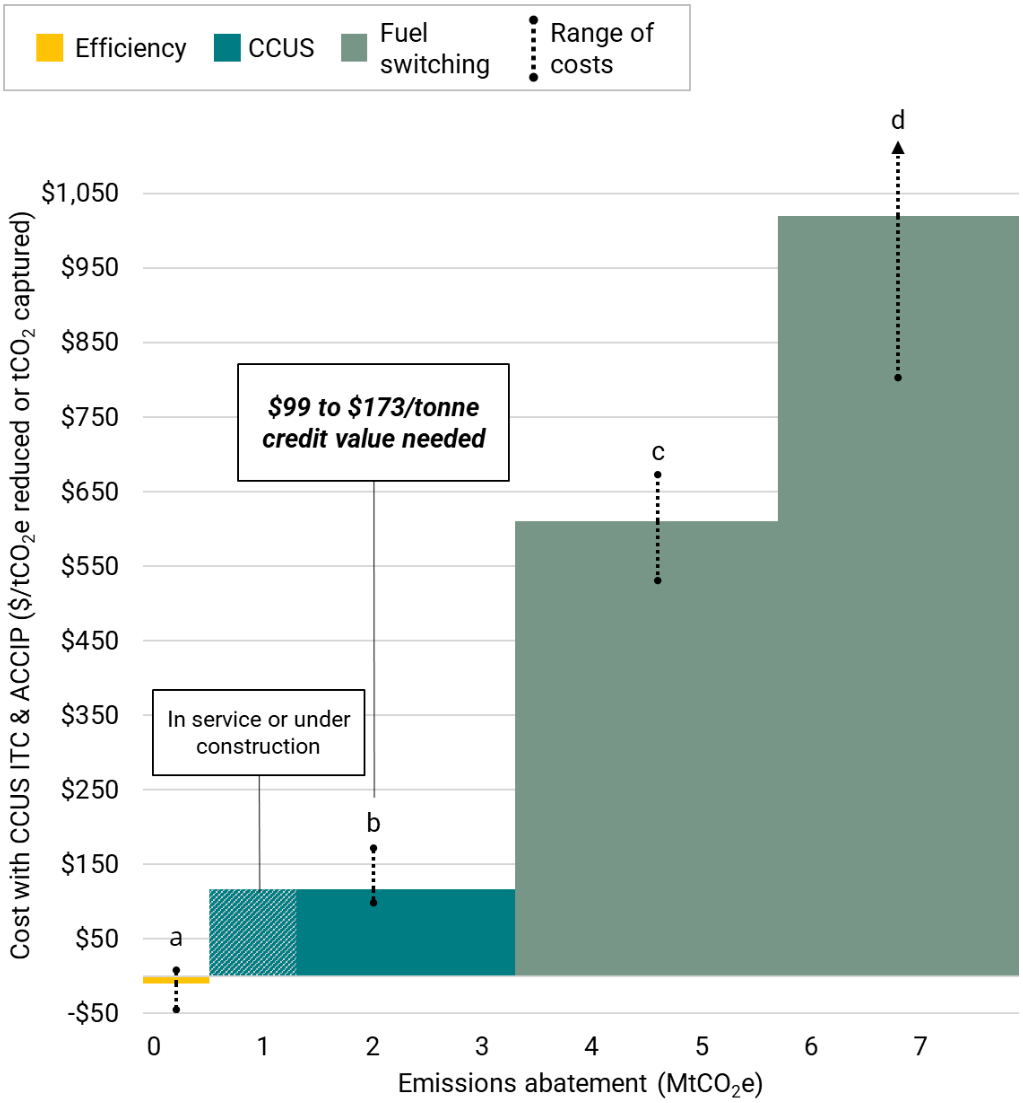
Several low-carbon projects are already underway at existing refineries, including the Sturgeon Refinery's carbon capture project[24] (located outside Refinery Row on the ACTL), Imperial Oil's

[23] Emissions sources are derived from averages across 2022 and 2023 National Inventory Reports. Percentages may not sum to 100% due to rounding.

[24] Capture of 1.2 $MtCO_2$ per year and integrated with the ACTL.

renewable diesel project[25] and Shell's anticipated Polaris carbon capture project at its Scotford refinery.[26] However, realizing the full potential of this regional cluster will require targeted policy support: enabling frameworks for shared CO_2 and hydrogen infrastructure, capital cost support for early adopters, and alignment of clean fuel incentives.

Figure 10: Marginal abatement cost curve for Alberta's refinery sector



a. Waste heat recovery systems
b. CCS for combustion and process emissions
c. Blue hydrogen (70% swap)
d. Green hydrogen (70% swap)

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[25] A $539 million investment for a production facility at the Strathcona refinery, with capacity to generate 20,000 barrels of renewable diesel per day.

[26] Capture of 650,000 tCO_2 per year from Shell's Scotford refinery and chemicals complex.

Carbon capture offers the largest and most cost-effective decarbonization investment opportunity for refineries, with potential to address both combustion and process emissions from sources such as heaters, boilers, and steam methane reformers. While it offers the greatest abatement opportunities overall — over 2.8 $MtCO_2e$/year — its deployment cost is likely on the higher end of our range, based on facility complexity. Several CCUS projects are also already underway at Alberta refineries, constraining additional emissions reduction potential. While combustion emissions originate from point sources like heater and boiler stacks, the large number of small, dispersed units across any given refinery makes carbon capture much more technically complex.

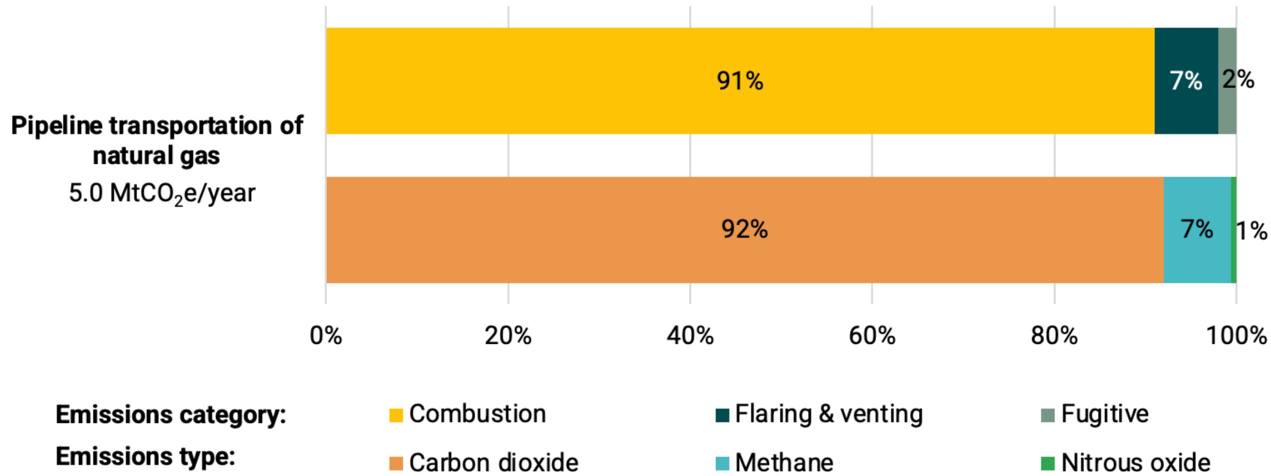
Fuel switching to hydrogen remains a longer-term opportunity. Blue hydrogen could reduce emissions from activities such as distilling crude oil, creating steam, and cracking hydrocarbons, at a moderate cost. Green hydrogen remains cost-prohibitive without incentives.

Waste heat recovery (WHR) systems are an efficiency upgrade that can capture thermal energy from multiple stacks. They offer energy savings and reliability benefits, but the majority of Alberta refineries have already integrated WHR systems for on-site power generation.

Pipeline transportation

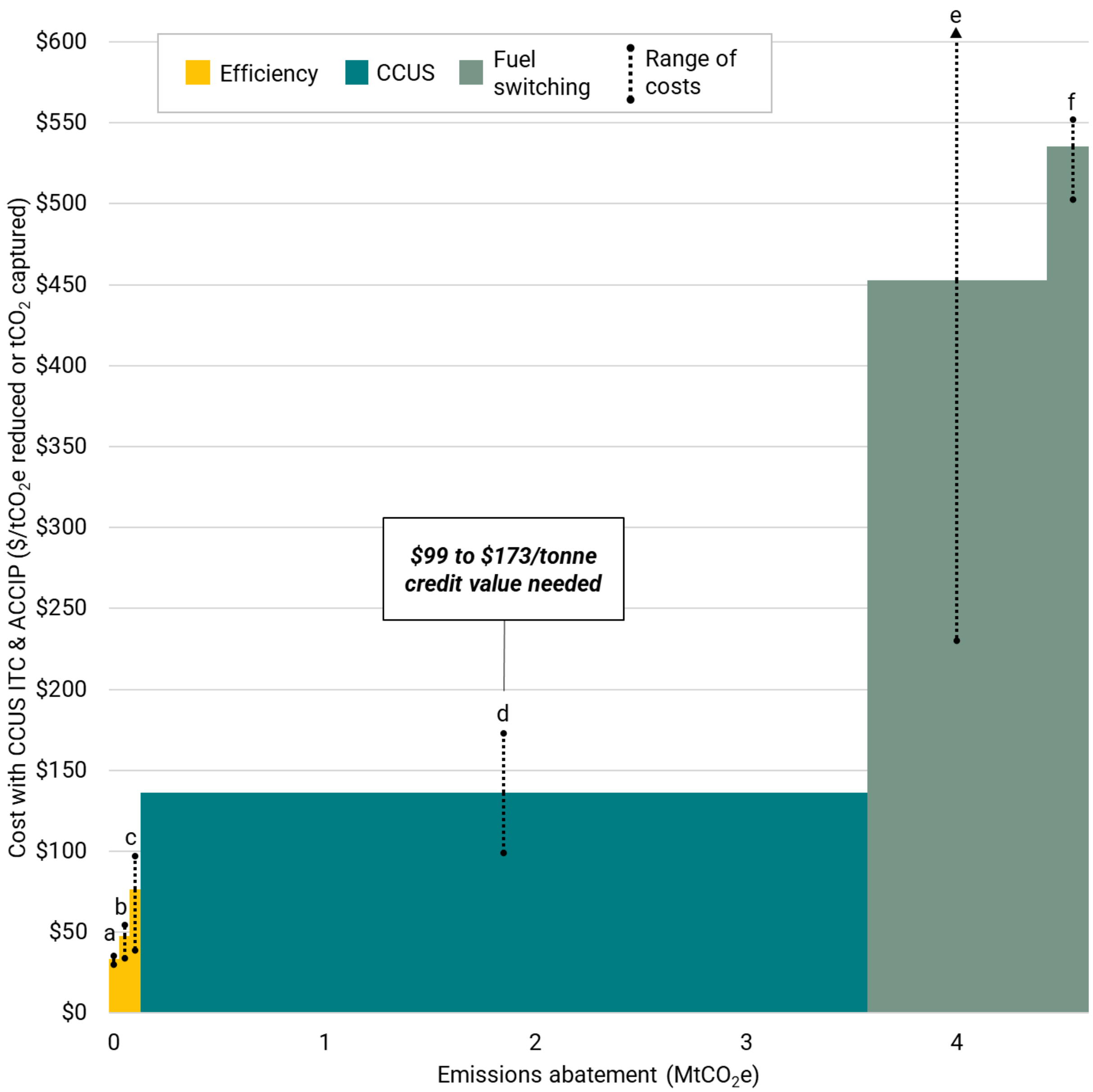
About 90% of pipeline transportation emissions arise from gas combustion at compressor stations. In 2019, pipeline transportation in [Canada] emitted a total of 10.7 $MtCO_2e$, 8.3 million of which came from combustion at compressor stations, with 4.5 million per year on average from Alberta. Pipeline transportation produces no process emissions, distinguishing it from other sectors.

Figure 11: Emissions profile for pipeline transportation[27]



[27] Emissions sources are derived from averages across 2022 and 2023 GHGRP reports.

Figure 12: Marginal abatement cost curve for Alberta's pipeline transportation



a. Replace pneumatic devices with mechanical controllers
b. Replace pneumatic devices with air-powered devices
c. Replace pneumatic devices with electric devices
d. CCS for combustion emissions from gas compressors
e. Renewable natural gas (20% swap)
f. Renewable energy-supported compression

This distinct emissions profile means fuel switching is the most significant abatement opportunity for pipelines. All fuel-switching options face significant obstacles to implementation. RNG supply is severely constrained; renewable energy offers limited abatement potential; hydrogen faces operational challenges, such as throughput losses and mechanical-drive turbine readiness. Pipeline operations typically self-fuel with natural gas drawn from the pipeline itself, a significant barrier to low-carbon fuel switching in larger volumes.

Cost-effective fuel switching would require incorporating low-carbon fuels into new pipeline infrastructure from the outset. This could include deploying low-carbon fuel-ready compressors, low-carbon electrification, and CCUS for residual emissions. Siting new pipelines near CO_2 transport corridors and hydrogen hubs — or building parallel CCUS pipeline infrastructure — would reduce long-term infrastructure costs.

Efficiency measures offer quick wins, but their emissions reduction potential remains modest compared to deeper decarbonization pathways. Low-cost measures like replacing pneumatic devices can deliver immediate net savings but with limited emissions impacts. Alternative pneumatic devices primarily reduce vented methane, which accounts for a relatively small share of total emissions.

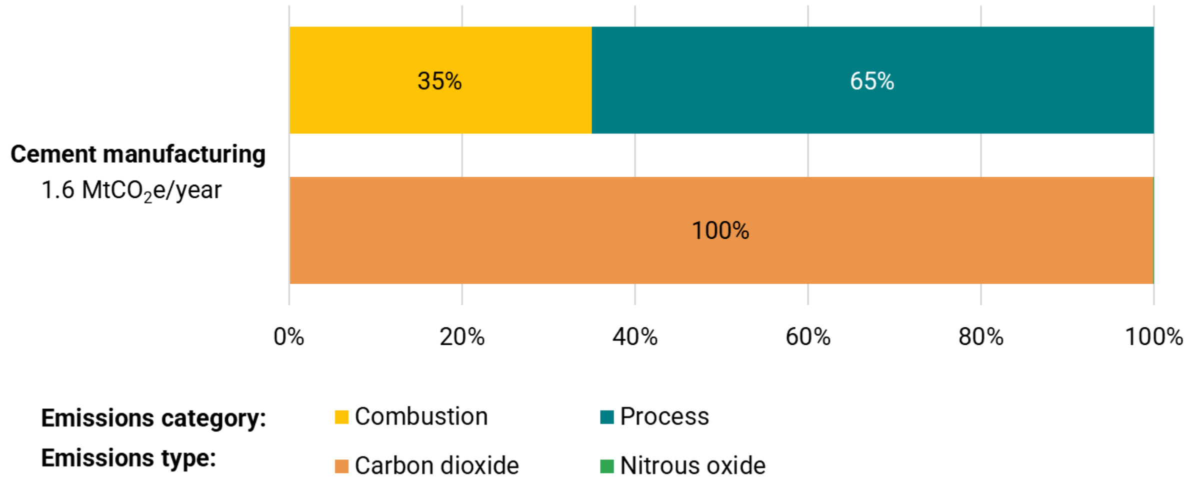
In the absence of robust policy support for low-carbon fuel switching, carbon capture would deliver emissions reductions at a lower cost. However, the current dispersion of compressor station infrastructure increases the complexity of capture deployment. Long-term fuel-switching opportunities are dependent on significant cost declines for low-carbon fuels, either through technological improvements, policy incentives, or both.

Cement manufacturing

Cement manufacturing has a unique emissions profile. About two-thirds of its emissions arise from the process of calcining limestone; the remaining third come from combustion to generate heat for the kiln. In Alberta, this corresponds to over one million tCO_2e annually from calcination and 573,000 tCO_2e from combustion.

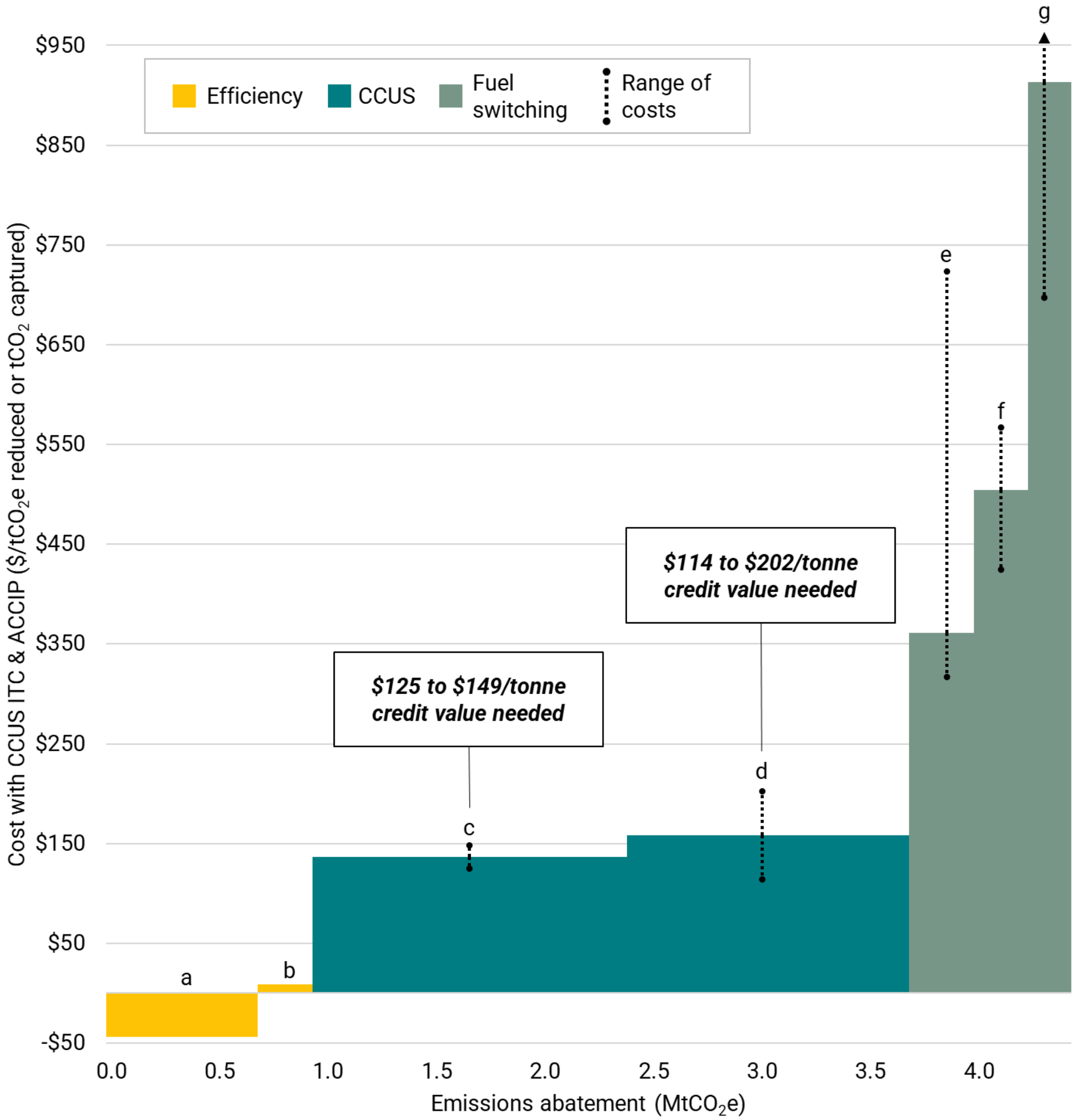
Alberta's cement sector consists of two large manufacturers, both of which are exploring or implementing identified technology pathways: Amrize Canada's (previously Lafarge Canada) Exshaw Cement Plant and Heidelberg Materials' Edmonton Plant.

Figure 13: Emissions profile for cement manufacturing[28]



[28] Emission sources are derived from averages across GHGRP and industry reports.

Figure 14: Marginal abatement cost curve for Alberta's cement sector



a. Supplementary cementitious materials (40% replacement)
b. Upgrade kilns with preheaters and precalciners
c. CCS for process emissions, and CCS for combustion emissions (oxyfuel only)
d. CCS for process emissions, and CCS for post-combustion emissions
e. Biomass-fueled precalciner
f. Blue hydrogen-fueled kiln
g. Green hydrogen-fueled kiln

Carbon capture is the primary pathway to address both process and combustion emissions. We estimate costs of about \$158/tCO_2 captured on over 80% of total emissions, with ACCIP and the federal CCUS ITC. Oxyfuel combustion produces an emissions stream with higher CO_2 concentration and can further bring down post-incentive costs to about \$137/tCO_2 captured, but these retrofits are more technically and operationally complex than conventional post-combustion capture.

One CCUS project proposal in Alberta's cement sector is quite advanced. Heidelberg Materials' proposed carbon capture project at its Edmonton cement plant could capture over one million tCO_2 per year, a global FOAK. Its success would be a watershed moment for the sector, but the project has struggled to reach a final investment decision, underlining the need for substantial operational support (e.g. carbon credit revenue).

Addressing combustion emissions, the remaining third of emissions in the cement sector, will require a mix of efficiency and fuel switching. Facilities have already implemented the majority of efficiency improvements, although there is opportunity to achieve further abatement from increased production of blended cements. Fuel switching targets combustion emissions, but technical and cost barriers — particularly for hydrogen — limit widespread application without policy support. Biomass offers a lower-cost, technically compatible alternative, demonstrated by both Amrize's and Heidelberg's low-carbon fuel projects aiming to displace up to 50% of natural gas use.

To move beyond marginal gains, policy should prioritize unlocking investment in larger projects focused on abating process emissions.

Utilities

The utility sector requires a distinct approach from other industrial sectors due to its emissions profile, regulatory structure, and pending market restructuring. Approximately 75% of Alberta's electricity generation is gas-fired.[29]

Utility decarbonization is not only a set of technological choices but a broader, interdependent system transition. Manufacturing industries have a range of retrofit and fuel-switching options, but deep decarbonization of Alberta's utility sector would require a transformation of its asset base and operating model. Decarbonization of utilities' scope 1 emissions would have knock-on effects resulting in indirect emissions reductions in other sectors' scope 2 emissions.

Alberta's current grid intensity is high enough that widespread industrial electrification would result in a net increase in provincial emissions (scope 1 for the utilities sector; scope 2 for industry). Accounting for both scopes, we estimate that reducing grid intensity by two-thirds and electrifying five sub-sectors could result in 6.3 MtCO2e of annual emissions reductions.[30]

Fuel switching for gas-fired power — to hydrogen or biofuels, for example — alters the underlying business model for power generators in Alberta. We estimate that there are 41 large power generation facilities regulated under TIER, with only three biomass plants generating electricity from low-carbon fuel sources. In the short term, options such as fuel blending or peaker plant retrofits may offer marginal reductions compared to complete fuel switches.

Retrofits also have significant limitations. Because gas-fired generation with CCS has less ability to ramp than unabated gas-fired generation, these retrofits alter the operational role of power stations. Retrofitting enough gas-fired power plants with CCS would increase ramping demand on unabated units.

Alberta's electricity market design complicates the financial case for low-carbon retrofits at existing operations. Alberta's electricity market is a fully deregulated, energy-only system where generators are paid for electricity produced, with no compensation for capacity and no long-term revenue certainty. It is more difficult to justify large capital retrofits when existing assets have recovered costs and can bid into the market at lower prices. In this type of market, the economic case requires a stronger carbon price signal.

[29] 2024 generation value.

[30] Electricity grid displacement factor of 0.4602 tCO_2e/MWh in 2025.

Conclusion and recommendations

The November 2025 federal-Alberta MOU is a once-in-a-generation opportunity to redefine Alberta's economic future. To fulfil the promise of this MOU and get major projects off the ground, a combination of both capital and operational support is crucial. Our modelling shows that Alberta can unlock over $90 billion in capital expenditures and more than 70 Mt of annual emissions reductions with credit prices between $130 to $150 per tonne — including Phase 1 of the Pathways Alliance carbon capture project.

CCUS deployment faces high technology costs and infrastructure gaps

- **Policy uncertainty:** Despite some early movers, many CCUS projects hinge on generating competitive rates of return by selling TIER credits. CCUS will stagnate in Alberta unless proponents can be certain that TIER credits can offer a long-term revenue stream.

- **Gaps in infrastructure:** Scaling carbon capture requires more shared infrastructure for transportation. With 14.6 Mt of annual capacity, the ACTL remains Alberta's most underutilized in-ground asset. It currently transports 1.6 Mt per year (11% capacity). Used to its full capacity at a price of $150/tonne, the annual economic value of the ACTL's throughput is $2.19 billion. But even operating at full capacity, the ACTL would transport less than a quarter of the 69 Mt of CCUS potential that we calculate is possible with credit prices between $130 and $150 per tonne. The majority of these emissions are not produced in proximity to the existing path of the ACTL.

- **Government commitment:** Scaling carbon capture is as much a strategic decision as an economic decision. Without coordination and cost-sharing mechanisms like ACCIP, CO_2 transportation infrastructure faces a first-mover problem.

Fuel switching opportunities are limited by cost and the emissions intensity of Alberta's grid

- **Emissions intensity of the electricity grid:** We estimate that Alberta's grid emissions intensity needs to fall by 60% for electrification to achieve net emissions reductions across major sectors. Cutting grid intensity by two-thirds could abate 6.3 $MtCO_2e$ of annual emissions from electrification across our five modelled sectors, reflecting both scope 1 emissions reductions at electrifying facilities and additional scope 2 emissions from electricity generation.

- **High technology costs for hydrogen:** Integrating hydrogen use into existing operations often requires retrofitting or replacement of existing equipment. These technologies remain capital-intensive and, in many cases, have challenging economics.

- **Gaps in infrastructure:** Many facilities lack the infrastructure needed to transport and use low-carbon fuels, such as pipelines and compatible equipment for use or storage.

- **Limited fuel supply:** Where infrastructure exists, the availability of low-carbon fuels remains a constraint. Blue and green hydrogen, biomass, and RNG are unavailable in the quantities required for fuel switching at scale.

Efficiency improvements offer quick wins, but diminishing returns

- **Quick wins:** Many facilities have already enacted efficiency measures given their low costs and quick payback periods. Most remaining efficiency opportunities are larger and more capital-intensive with smaller incremental returns, longer payback periods, or both.

- **Site-specific barriers:** The potential for additional efficiency investments can vary significantly by site due to differences in facility age, design, and geography.

Based on our findings, we make the following recommendations to Alberta and federal policymakers:

1. **Finalize TIER market design rules to achieve a minimum effective credit price of $130 per tonne, including a timeline for achieving this price**.

   Establishing the timeline for this price trajectory as soon as possible is required to unlock tens of billions of dollars worth of shovel-ready low-carbon projects. This includes Pathways Phase 1, which the MOU states will be built and commence operations beginning in 2027, which only adds to the urgency of finalizing new rules for TIER.

   High credit prices — not the headline price — are what matter most to project proponents and investors, and are the province's most efficient tool to unlock new investment dollars while reducing emissions. TIER credit prices have declined steadily since 2023 and traded below $20 per tonne in November 2025. Reversing this trend as soon as possible, and ideally achieving $130 per tonne by 2030, can get low-carbon projects going faster.

2. **Implement the financial mechanism outlined in the Canada-Alberta MOU in the form of joint carbon contracts for difference (CCfDs)**.

   CCfDs should be jointly backstopped by the Government of Alberta and the Government of Canada to ensure that both parties maintain their commitments on TIER, and to provide near-term certainty for industry. CCfDs are the most powerful tool available to make TIER credits bankable for proponents and unlock low-carbon investments.

   The size of the program should be substantial (e.g. targeting 50 Mt worth of annual emissions reductions or more). Importantly, governments can structure even a large program in ways that create little or no direct fiscal cost and avoid inflating deficits, while still complying with Public Sector Accounting Standards.

We make the following recommendation to Alberta policymakers:

3. **Make ACCIP a more bankable incentive for CCUS projects.**

   ACCIP can help solidify Alberta's first-mover advantage and position the province as a leader in CCUS. The Government of Alberta should alter ACCIP's payout structure so that eligible expenditures can be claimed in the year they are incurred, rather than paid in three installments over three years after year one of operations. This would significantly increase the program's value to project proponents.The addition of a recovery mechanism could ensure that grant funding would be returned if a project is shelved. ACCIP could be also redesigned to reduce interactions with other policies, such as the cost-based royalty payout system for oil sands facilities.

We make the following recommendations to federal policymakers:

4. **Lift the CCUS ITC's exclusion of enhanced oil recovery** (EOR) for capture and transport infrastructure. EOR with sequestration is a near-term opportunity to develop shared infrastructure and facilitate "learning by doing." Most EOR is already profitable on its own, so this change should apply to capture and transport costs at reduced rates (e.g. half the rates for capture and transport for other eligible uses), recognizing that these investments will contribute to development of learning curves and shared infrastructure that can reduce costs for future CCUS projects. Strong recovery mechanisms in the CCUS ITC would need to be expanded to EOR to ensure additionality and eliminate free-riding.

5. **Finalize the Clean Electricity ITC.** Low-emissions electricity is an important complement to CCUS. With the current emissions intensity of Alberta's grid, fuel switching from natural gas to electricity drawn from the provincial grid would increase emissions. A less emissions-intensive grid can unlock significant economic opportunities across Alberta, conserving natural gas for higher-value uses than domestic combustion. Implementing the Clean Electricity ITC can help accelerate the buildout of power projects of all kinds in Alberta — nuclear, geothermal, wind, solar, transmission, storage, and more. The 2025 federal budget reaffirmed the government's intention to legislate the Clean Electricity ITC. It should be finalized as soon as possible.

Appendix

Table 1: Drivers of uncertainty

The MAC curves visualized in this paper represent median estimates. The final cost and abatement potential of each technology solution will vary. The cost and emissions abatement are impacted by each facility's unique operations, including vintage and complexity of operations.

Driver / Tech	CCUS	Efficiency	Fuel Switching
Efficiency of operations	**CO_2 concentration of emissions and flue gases:** lower costs for higher CO_2 concentration and higher costs for lower CO_2 concentration.	**Waste heat recovery (WHR) method:** cost and emission abatement of WHR systems depend on stream source (e.g. exhaust air, hot water, or steam) and recovery method (e.g. heat exchanger, regenerative thermal oxidizers, etc.).	**Energy content of low-carbon fuels:** abatement costs depend on equipment and fuel (e.g. H_2, RNG). Low-carbon fuels have varying carbon intensities and higher heating values (HHVs). Lower carbon intensities and higher HHVs lead to lower MACs.
	Energy penalty: CCUS equipment uses large amounts of electricity. The size of a project's "energy penalty" (i.e., emissions associated with the additional energy use) impacts net emissions abatement if electricity is produced from natural gas.	**Reservoir conditions and bitumen quality (in-situ oil sands sub-sector):** the conditions of the extraction site impacts the costs of alternative SAGD processes.	**Efficiency rates:** electric equipment is typically more efficient than fossil fuel-based equivalents. Emissions abatement from additional scope 2 power generation and relative electricity required to displace fossil fuels depends on the difference in efficiency rates between the original equipment and electric replacements.
Cost of inputs	**Cost of electricity:** carbon capture equipment uses 0.10 MWh/tCO_2 for high CO_2 concentration to 0.5 MWh/tCO_2 for low CO_2 concentration. Project costs will depend on electricity prices.	Generally not applicable (exception: cost of supplementary cementitious materials in cement manufacturing: costs vary based on source, distance for transport, and supply constraints.)	**Costs of electricity, RNG, and hydrogen**: electrification costs depend on electricity prices. Costs for hydrogen and RNG are similarly varied based on type, price, source, and distance transported.

Availability of inputs	—	**Supply of supplementary cementitious materials (cement manufacturing sector):** supply of fly ash over the long-term is uncertain as Alberta has phased out coal power plants. Legacy stockpiles and landfills can offer sources in transition.	**Supply of RNG and hydrogen:** the portion of fossil fuels displaced with RNG and hydrogen at an individual facility or sector is dependent on the availability of the fuels.
Deployment readiness	**Policy readiness:** supportive regulatory frameworks influence the pace of CCUS deployment, impacting project costs over the long-term development of the technology. Capital costs can also vary based on the permitting process.	**Policy readiness:** regulatory frameworks influence the pace of technological advancements, impacting project costs over the long-term development of the technology.	**Feasibility of small modular reactors (SMRs):** Alberta is still in early stages of development.

Table 2: Credit Types in TIER

Credit Type	Credit Generator	Traded on Market?	Unique Attributes
TIER fund credits	Government of Alberta	**No**	Cost of credits based on headline carbon price ($95 per tonne in 2025) Cannot be banked
Emissions performance credits	Facilities directly regulated by TIER	**Yes**	Trade at a discount to the headline carbon price
Offset credits	Any offset developer	**Yes**	No limit to who can generate offsets or how many, based on protocols approved by the Government of Alberta
Sequestration credits	Offset credit holder	**Yes**	New instrument that can be "stacked" with the federal CFR
Capture recognition tonnes	Offset credit holder	**No**	New instrument that reduces regulated emissions, but can only be converted and used by the capturing facility

Table 3: Benchmarks in TIER

	Facility-specific benchmarks (FSBs)	High-performance benchmarks (HPBs)
Description	• Based on emissions and production from set baseline years.	• Based on the performance of the best 10% of facilities in a specific sector.
Source	• Determined based on verified facility-specific data for the baseline years.[31]	• Established in the TIER regulation and by ministerial order
Tightening rate[32]	• Most FSBs: Begin at 14% in 2023 and reduce by 2% annually Exceptions • FSB - Bitumen - Oil Sands In Situ: Begins at 14% in 2023, reduces by 2% annually until reducing by 4% annually in 2029 and 2030 • FSB - Bitumen - Oil Sands Mining; Upgrading: Begins at 20% in 2023, reduces by 2% annually until reducing by 4% annually in 2029 and 2030	• Most HPBs: Begin at 2% in 2023 and reduce by 2% annually Exceptions • HPB - Bitumen - Oil Sands In Situ: Begins at 2% in 2023 and reduces by 2% annually until reducing by 4% annually in 2029 and 2030 • HPB - Bitumen - Oil Sands Mining; Upgrading: Begins at 8% in 2023 and reduces by 2% annually until reducing by 4% annually in 2029 and 2030
Benefits	• Lower-performing facilities are not competing with more efficient facilities within the sector. Provides flexibility for facilities that are not yet sector leaders.	• Prevents high-performing facilities from competing against their own historical data, which would penalize first movers.

[31] Baseline years are generally 2013-2015. New facilities are subject to a rolling benchmark, using year 2-4 of operations for the final FSB.

[32] Treatment as of updated program design effective January 1, 2023. Tightening rates differed in previous compliance periods.

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