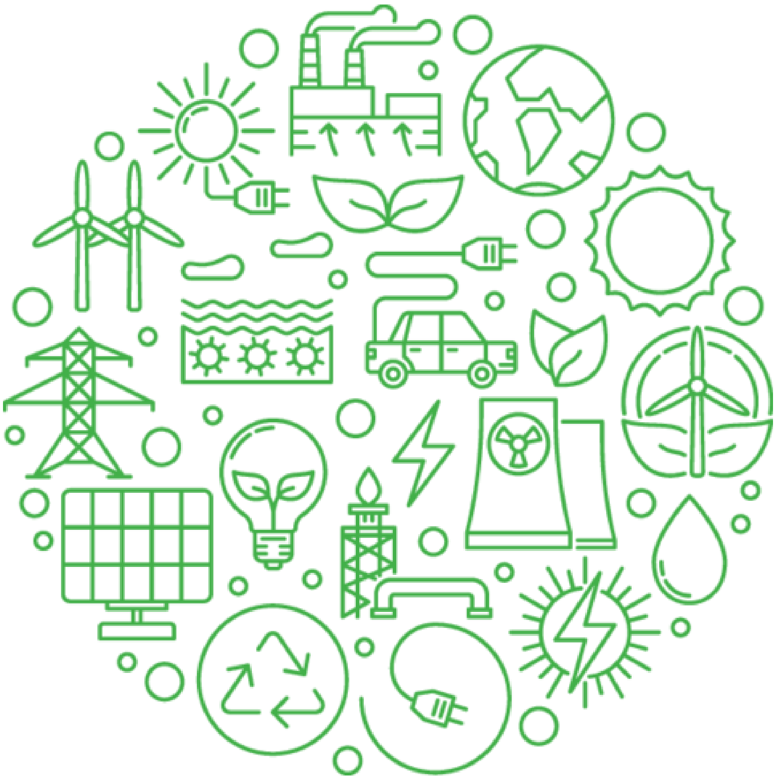

Potential Economic Impact of the Proposed Federal Oil and Gas Emissions Cap

Prepared for Treasury Board and Finance, March 27, 2024

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1. Executive Summary

In December 2023, the Government of Canada announced its intention to implement a nationwide cap-and-trade system covering the upstream oil and gas sector (the Cap). The proposed Cap would be implemented through regulations under the Canadian Environmental Protection Act, 1999 (CEPA). The Cap would constrain sectoral greenhouse gas (GHG) emissions in line with Canada's 2030 climate goals.

Deloitte was engaged to conduct an economic impact analysis of the proposed Cap. Deloitte's approach consisted of two analyses.

- The first analysis consisted of an assessment of the extent to which the proposed Cap would be met through investments in emission reduction technologies, as opposed to a reduction in production of oil and gas.
- The second analysis consisted of assessing the economic impacts of these investment and production outcomes on the economies of Alberta and the Rest of Canada.

In the attached report, we first provide an estimate of the magnitude of the emission reduction required in the sector to comply with the Cap. The regulatory framework proposed a cap on emissions in the rage of 106-112 Mt CO2e by 2030, with the system phasing in between 2026 and 2030. The framework alludes to the consideration of compliance flexibility mechanisms including: emission trading; 3-year compliance periods; allowance banking; a decarbonization fund and Output-Based Pricing System Regulation compliant offsets. If emissions exceed the cap, a limited number (25 Mt in 2030) of compliance units (offsets and decarbonization fund units) could be acquired and applied to meet the emissions cap, up to the legal boundary. With the application of these compliance units, the legal upper bound of sector emissions under the cap could be in the range of 131-137 Mt CO2e.

We estimate that current (2021) emissions are 161 Mt CO2e and that by 2030 business-as-usual emissions (BAU) for the sector will total 157Mt. This 2030 estimate includes expected reductions of roughly 5 Mt CO2e of GHG reductions resulting from continued improvement in production efficacy (emissions per unit of output) and a 20 Mt C02e of emission reductions from actions related to abatement of methane associated with fugitive and venting related sources.

As a result, BAU emissions would be 45 Mt CO2e over the upper range of the Cap (106-112 Mt CO2e). Under the assumption that the sector maximizes the 25 Mt CO2e afforded via compliance flexibility units, emissions would exceed the Cap by 20 Mt CO2e (Figure 1). Achieving the 20 Mt CO2e in reductions to meet the compliance threshold will require significant investment in carbon capture and storage and/or a reduction in production and associated emissions.

Figure 1: Canada Total Oil and Gas Emissions Forecast

	2030 Emissions Level (Mt CO2e)
Emissions Cap	*112*
Available Offsets	*25*
Allowable Emissions	**137**
BAU Emissions Forecast	**157**
Gap to be Met Through Oil Sands CCS or Production Curtailment	**20**

To assess the likelihood of CCS investments proceeding, we developed corporate financial models of two representative assets in the oil sands. These models allowed us to compare the financial implications of investing in CCS versus curtailing production to meet the cap. The results are summarized in Figure 2 below. For each of the assets (a high-cost producer and a low-cost producer) production curtailment leads to higher asset values than investing in CCS abatement.

Figure 2: Discounted Cashflow Comparison for Low-Cost and High-Cost Assets

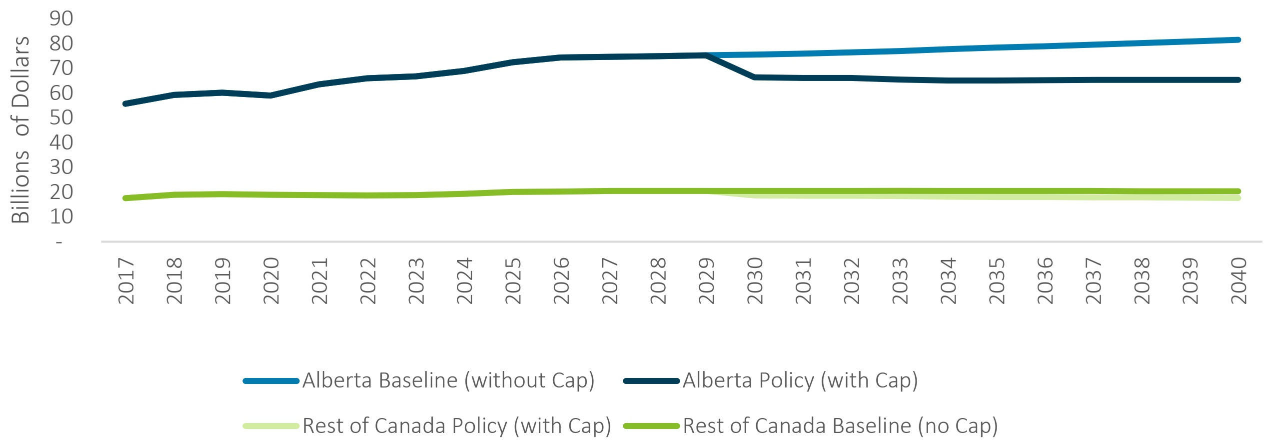
Discounted cashflow ($million)		
	Low-Cost Asset	High-Cost Asset
Base Forecast (10% WACC)	4,617	401
Production with CCS (15% WACC)	2,447	(906)
Production curtailment (10% WACC)	3,641	369
Production curtailment vs CCS	1,194	1,275

This estimate is subject to a number of assumptions. We analyze the sensitivity of the results to those assumptions and find that the results are robust. The implication is that production in the sector will be lower across four provinces as set out in Figure 3. Additionally, from 2030 to 2040, we assume that the Cap will remain at 137Mt CO2e, thereby limiting the emissions level in the sector during this period. The impact on national production in the sector is depicted in Figure 4 below.

Figure 3: Emissions and Production Forecast by Province

	Emissions Level 2030 (Mt CO2e)	Decrease in Production	2030 BAU Production Volumes	Percentage Difference: 2030 BAU Production vs Decrease in Production
Alberta	**134.5**			
Total Oil	105.9	-526,000 b/d	5,141,000 b/d	-10%
Conventional Oil Production	14.2	-114,300 b/d	1,408,000 b/d	-8%
Oil Sands	91.7	-411,800 b/d	3,733,000 b/d	-11%
In situ bitumen	55.4	-205,100 b/d	2,071,000 b/d	-10%
Mined bitumen	36.4	-206,600 b/d	1,662,000 b/d	-12%
Conventional Gas	28.6	-1.37 Bcf/d	9 Bcf/d	-16%
BC	**11.4**			
Conventional Oil Production	0.5	-14,600 b/d	234,000 b/d	-6%
Conventional Gas	10.9	-0.77 Bcf/d	8.61 Bcf/d	-9%
Newfoundland and Labrador	**1.0**			
Conventional Oil Production	1.0	-26,200 b/d	361,100 b/d	-7%
Saskatchewan	**9.6**			
Conventional Oil Production	8.5	-54,300 b/d	519,200 b/d	-10%
Conventional Gas	1.1	0.04 Bcf/d	0.35 Bcf/d	-11%

Figure 4: Oil and Gas Sector, Real GDP under Policy, and Baseline, $B (2017 dollars)



We then estimated the economic impacts from the lower oil and gas production. This assessment was carried out using Deloitte's Computable General Equilibrium ("CGE") model, which is a large scale, dynamic, multi-region, multi-commodity model. The economic impact of the Cap is measured by comparing the economic evolution under the Policy scenario (economy under the Cap) to the Baseline scenario (without the Cap).

The Cap results in a significant decline in GDP in Alberta and the Rest of Canada. The main sources of impact are lower oil and gas activity and output, which reduce employment, income, and investment in the country through lower demand for goods and services, including labour and capital services, a lower rate of return on investment and a higher price of oil. The negative impacts on the economy are somewhat mitigated by a lower Canadian dollar, which raises the cost of imported goods for consumers and businesses but provides a partial offset to the output shock by lowering the price of Canadian exports. Also, lower wage rates across the economy, although negative for individuals, facilitate reallocation of labour among sectors and labour market adjustment.

In 2040, Alberta's GDP is estimated be lower by 4.5% and Canada's GDP by 1.0% compared to the baseline. Because we assume that the Cap is a permanent measure, the shift in the output of the oil and gas sector and associated losses are permanent and accumulate over time. Cumulatively, over the 2030 to 2040 period, we estimate that real GDP in Alberta is $191 billion lower and real GDP in the Rest of Canada is $91 billion lower, compared to the baseline scenario ($2017 dollars).

The level of employment is also lower: by 2.0% in Alberta and 0.5% in Canada compared to the baseline in 2040. Alberta is estimated to lose on average 55,000 jobs and Rest of Canada 35,000 jobs between 2030 and 2040. As a result of lower employment opportunities, 2,400 individuals are estimated to move from Alberta to other provinces annually, or 25,880 in total over the 2030-2040 period.

Figure 5: Macroeconomic Metrics: Deviation, Policy vs Baseline, 2040

	Alberta	Rest of Canada	Canada
Oil and Gas Real GDP	-20%	-13.3%	-19%
Oil and Gas Real GDP (2017 Dollar, $B)	-16.2	-2.7	-18.9
Real GDP	-4.5%	-0.4%	-1.0%
Real GDP (2017 Dollar, $B)	-23.4	-11.1	-34.5
Real Investments	-3.6%	-0.5%	-1.0%
Real Household Consumption	-3.9%	-0.4%	-1.0%
Real Exports	-7.5%	-0.3%	-1.4%
Real Imports	-5.8%	-0.3%	-1.2%
Employment	-2.0%	-0.2%	-0.5%
Employment (Thousands)	-69.5	-43.4	-112.9
Real Wages	-2.2%	-0.2%	-0.5%
Exchange Rate (CAD/USD)	-2.0%	-2.0%	-2.0%
Price of Imports in CAD	1.9%	1.9%	1.9%
Price of Exports in CAD	0.5%	-0.1%	0.0%
Terms of Trade	-1.3%	-2.0%	-1.9%
Government Tax Revenues	-5.8%	-0.5%	-1.3%

2. Producer Reaction to the Cap

This section sets out our expectations of how oil and gas producers will adjust their operations to comply with the proposed Cap. The analysis first sets out the obligation imposed by the Cap on producers by calculating emissions that will likely result from "business as usual" operations. To do this we project the current paths of both future oil and gas production and future emissions through 2040, based on current policy, absent of the proposed Cap. The net result of this analysis is that in the absence of the Cap, oil production will increase by over 30% and gas production over 16% from 2021 through 2040. Emissions, however, are projected to decline somewhat over the same period. These declines are largely the result of regular capital upgrades and significant efforts to reduce methane emissions. After accounting for these factors, we expect that the Cap imposes 20 Mt in emissions reduction on producers by 2030, which will need to be achieved via CCS investments, or through production curtailment.

To determine whether producers are likely to invest in CCS or reduce production, we developed simplified financial models of representative assets to assess the least costly means of reducing emissions. The net result of these models is that the least costly adjustment is to curtail production. Because the estimates rely on a significant number of assumptions, we test their sensitivity to different assumptions.

This analysis is set out in the following five sections:

i. Production and Emissions Projection
ii. Financial and Policy Context
iii. Cash Flow Projections
iv. Producer Reaction to the Cap and implications for oil and gas output
v. Sensitivity Analysis

i. Production and Emissions Projection

To assess the Cap's impact, it is first necessary to define how production and emissions in the sector would evolve in its absence, in other words the business-as-usual scenario (BAU).

Upstream oil and gas production forecasts are based on the Canada Energy Regulator's (CER) Current Measures scenario. We use the CER's Current Measures scenario as this reflects current policies in place today.[1] In contrast, the federal government used the CER's Canada Net Zero scenarios as a proxy for BAU. In our analysis, we have chosen the CER's Current Measures scenario because the Net Zero scenarios assume the implementation of significant new policies to achieve net-zero, which are not currently in place. As a result, the CER net zero scenarios are not reflective of a BAU scenario. For the sake of clarity, the CER Net Zero scenarios are not forecasts, these scenarios simply indicate the abatement that must occur for the national 2030 target to be met. Emission reductions associated with oil and gas are but one component of the reductions that must occur for the economy to reduce emissions from over 650 Mt CO2e to Canada's 2030 target of approximately 440 Mt CO2e.

As depicted in Figure 6 and Figure 7 ,the CER's Current Measures scenario projects a substantial increase of over 30% in oil production and 16% in gas production between 2021 and 2040 in Canada. In Alberta, oil production is projected to increase 35% between 2021 and 2040, and gas production is projected to decrease 14% between 2021 and 2040.

[1] Canada Current Measures is defined by the CER as a scenario where limited action takes place in Canada to reduce GHG emissions beyond measures in place today.

Figure 6: Forecast for Oil Production, under Canada Current Measures (Thousand barrels a day)[2]

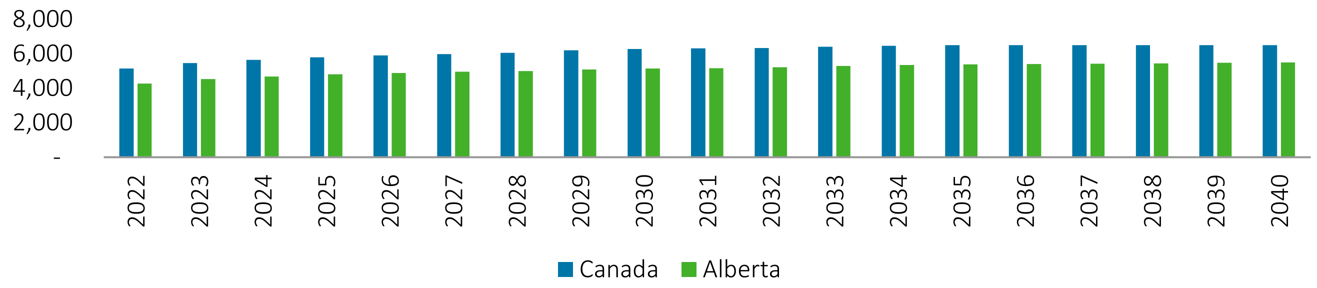
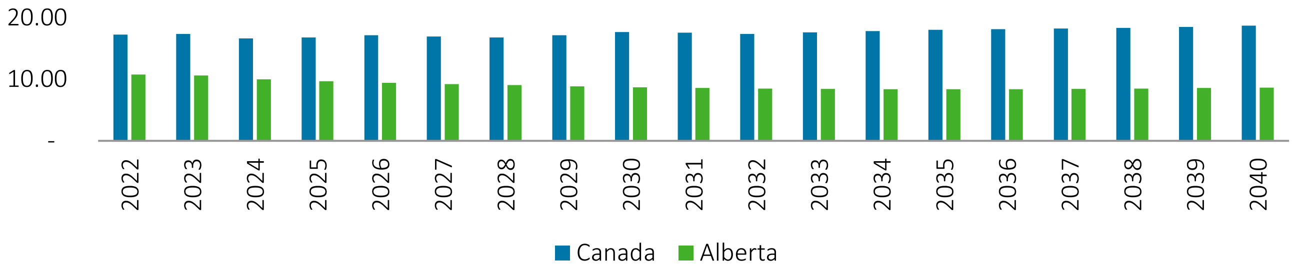


Figure 7: Forecast for Gas Production in Canada (Bcf/d)[3]



While we use the CER production forecast, we estimate our own emissions profile for 2030 and through 2040. This allows us to forecast emissions in a more detailed manner (i.e., by province, type of oil production technology, and natural gas). Additionally, we incorporate the observed reduction in emission intensity levels from 2019 to 2021. We first estimate emissions assuming unchanged emissions intensity per unit of output. We then estimate likely emissions reduction from three main sources: ongoing **efficiency improvements per unit of output;** ongoing **methane emissions reductions;** and individual **carbon capture and storage** (CCS) projects that we expect to proceed.

BAU Emissions

Nationally, without further efficiency improvements or methane abatement, we project overall emissions in the sector to increase, as production increases, from 161 Mt CO2e in 2021 to 184 Mt CO2e in 2030 and 191 Mt CO2e in 2040.

However, we expect that ongoing efficiency improvements will reduce emissions by 5 Mt CO2e by 2030 and 7 Mt CO2e by 2040. Ongoing methane abatement will further reduce emissions by 20 Mt CO2e in 2030 and by 31 Mt CO2e by 2040. Effectively we expect that Canada's oil and gas methane abatement target of -75% below 2012 levels is met in 2040 as opposed to the Federal ambition of 2030.

We expect that the implementation of CCS initiatives in the BAU scenario will primarily be undertaken by gas producers, at a modest scale, based on a recently announced agreement to backstop carbon credit in the sector. Our expectation is that investments by the Canada Growth Fund in Entropy Inc. will lead to abatement of 1 million tonnes of CO2e by 2030.[4]

In total, therefore, based on current policy and before the impact of the Cap, we expect:

- Oil production in Canada to increase by 27% by 2030 and 32% by 2040 from 2021 levels.
- Gas production in Canada to increase by 10% by 2030 and 16% by 2040 from 2021 levels.

[2] Exploring Canada's Energy Future. Canada Energy Regulator. Canada's Energy Future 2023. Source: Exploring Canada's Energy Future - Canada Energy Regulator (cer-rec.gc.ca)

[3] Exploring Canada's Energy Future. Canada Energy Regulator. Canada's Energy Future 2023. Source: Exploring Canada's Energy Future - Canada Energy Regulator (cer-rec.gc.ca)

[4] Canada Growth Fund announces strategic investment in Entropy Inc. and carbon credit offtake commitment. Cision. Dec. 20, 2023. Source: https://www.newswire.ca/news-releases/canada-growth-fund-announces-strategic-investment-in-entropy-inc-and-carbon-credit-offtake-commitment-836264045.html

- Emissions to decrease from 161 Mt CO2e in 2021 to 157 Mt CO2e in 2030 and 152 Mt CO2e in 2040 as set out in Figure 8.

Figure 8: Canada Total Oil and Gas Emissions Forecast

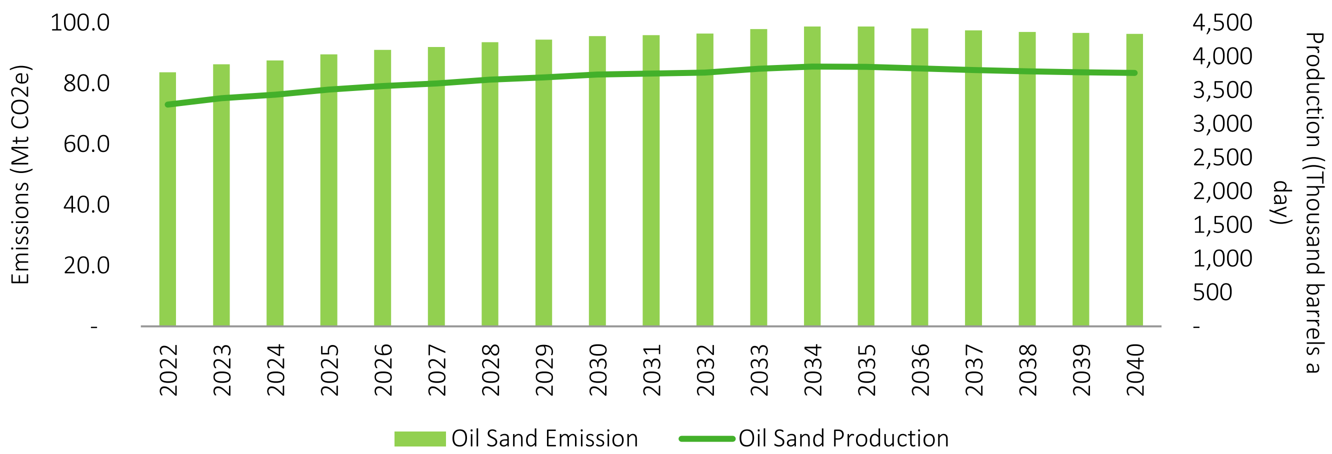
	2021 Emissions Level (Mt CO2e)	2030 Emissions Level (Mt CO2e)	2040 Emissions Level (Mt CO2e)
Emissions from Unabated Production	161	184	191
Emissions with Efficiency Improvement		178	184
Emissions with Methane Abatement		158	153
Emissions with Natural Gas CCS		157	152

The rest of this section sets out in greater detail how we arrived at the emissions projection described in Figure 8. The estimates were derived by province, by type of oil (conventional oil, oil sands mined and in-situ) and natural gas, assuming first that the emissions intensity per unit of production remains unchanged from the levels observed in 2021.[5] Based on this assumption we project the unabated emissions for each province from CER's Canada Current Measure production forecasts:

- 50% of emissions from the sector come from oil sands. In our forecast, emissions from oil sands are projected to increase from 84 Mt CO2e in 2022 to 96 Mt CO2e in 2030 and experience minimal growth, thereafter, remaining at approximately 96 Mt CO2e through 2040 (Figure 9).
- Emissions from conventional oil (includes all other oil types besides oil sands) are projected to rise from 29 Mt CO2e in 2022 to 43 Mt CO2e in 2040. These represent 21% of the emissions of the sector (Figure 10)
- Emissions from conventional gas (includes all natural gas types) remain relatively constant, decreasing from 54 Mt CO2e in 2022 to approximately 50 Mt CO2e throughout the period and account for about 30% of the emissions in the sector (Figure 11).

A detailed breakdown of unabated emissions by province is provided in Appendix A.

Figure 9: Canada Oil Sand Forecast



[5] Environment and Climate Change Canada Data Catalogue. October 2023. Source: ECCC Data Catalogue

Figure 10: Canada Conventional Oil Forecast

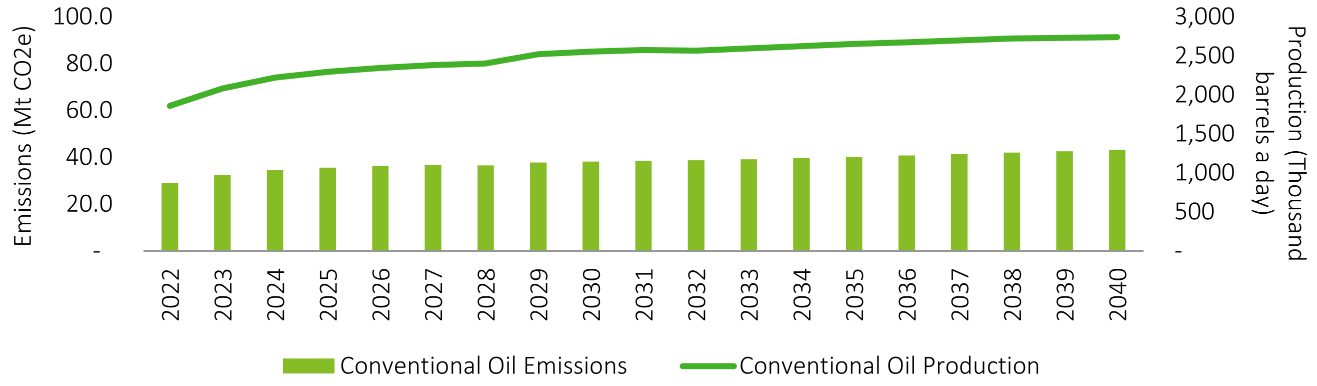
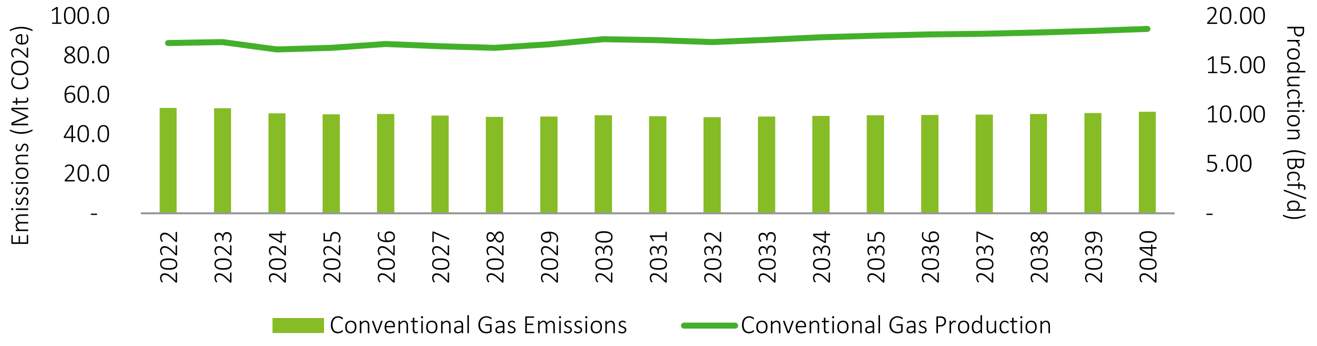
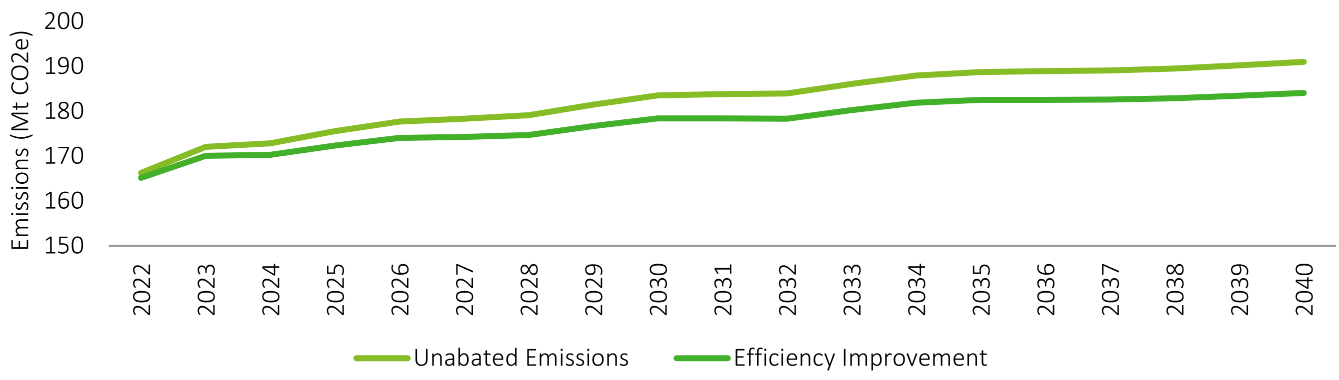


Figure 11: Canada Conventional Gas Forecast



We then develop estimates of potential future reductions in emissions per unit of output. In the past five years, the oil and gas sector has achieved ongoing improvements in emissions intensity. However, we anticipate that these improvements will gradually decelerate over time, consistent with historical trends. Based on these findings, as set out in Figure 12, efficiency improvements are projected to reduce emissions levels by 5 Mt CO2e in 2030 relative to unabated emissions intensity levels, and 7 Mt CO2e relative to BAU emission intensity levels by 2040.

Figure 12: Canada Total Oil and Gas Emissions Forecast, Efficiency Improvement

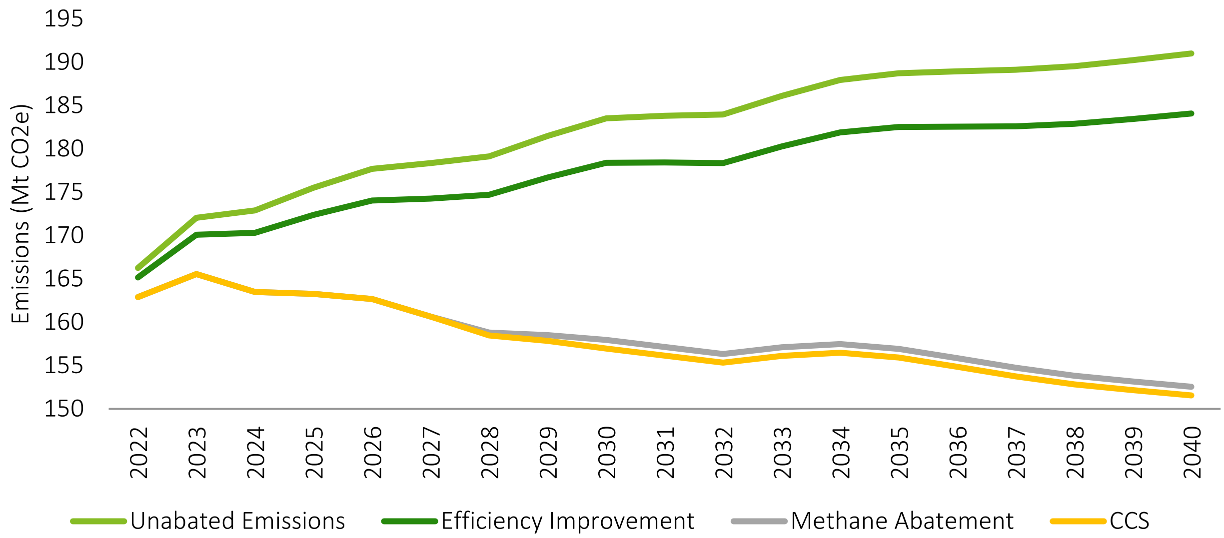


Next, we factor in expected reductions in methane from the sector. In September 2023, the federal government provided an update on their plan to reduce methane emissions in the oil and gas sector. Building on the 2018 commitment to reduce emissions by 40% to 45% from 2012 levels by 2025, the new goal is focused on a 75% reduction in methane emissions compared to 2012 levels by the year 2030.[6]

Based on a review of recent industry trends and our internal assessment of methane abatement potential, we expect a 60% reduction of 2012 methane levels by 2030 and a 75% reduction of 2012 methane levels by 2040. This results in a 20 Mt CO2e reduction in emissions relative to BAU efficiency improvement levels, and an additional 31 Mt CO2e reduction relative to BAU efficiency improvement levels by 2040.

In total, therefore, business-as-usual emissions in the sector are projected to total 157Mt CO2e in 2030 and 152 Mt CO2e in 2040. These are the emission levels against which to measure the obligation under the Cap of reducing emissions to 112Mt CO2e by 2030. The Cap, therefore, requires emissions to be reduced by 45Mt CO2e by 2030.

Figure 13: Canada Total Oil and Gas Emissions Forecast



The proposed Cap allows producers to utilize up to 25 Mt CO2e a year of compliance flexibility units (Output-Based Pricing System eligible offsets and/or decarbonization fund units) at the sectoral level to comply with facility-level emissions obligations. This raises the proposed cap on emissions to the effective legal upper bound from 112Mt to 137Mt CO2e in 2030. In this exercise, we made a simplifying assumption that the compliance flexibility units (specifically offsets) required for production would be readily available in the economy and obtainable by the oil and gas sector. We did not evaluate the potential availability or price of these offsets. It is important to note that this assumption implies that any shortfall in the availability of offsets would increase the emission reductions required, via CCS and/or production curtailment.

After allowing for offset purchases, as shown in Figure 14, we expect that the sector will need to reduce emissions by a further 20 Mt CO2e in 2030 to meet the obligations proposed within the regulatory framework. To achieve an abatement of this scale within this sector, the only viable emission reduction technology is CCS. This conclusion is consistent with ECCC's Regulatory Framework and the CER's analysis.

[6] Update on Path Forward for Oil and Gas Sector Methane Mitigation, September 2023. Source: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reducing-methane-emissions/update-oil-gas-sector-methane-mitigation.html

Figure 14: Canada Total Oil and Gas Emissions Forecast

	2030 Emissions Level (Mt CO2e)
Emissions Cap	*112*
Available Offsets	*25*
Allowable Emissions	137
BAU Emissions Forecast	157
Gap to be Met Through Oil Sands CCS or Production Curtailment	20

ii. Financial and Policy Context

CCS technology can capture and store substantial amounts of carbon dioxide, presenting a promising solution for reducing emissions. However, despite its potential benefits, the adoption and implementation of CCS involves significant capital investment and operating expenses. In this section, we set out a corporate financial model of two representative oil sands assets to examine whether producers are likely to invest, or curtail production, to meet their obligations under the Cap.

We consider two representative oil sands assets: low-cost and high-cost. The low-cost asset represents a newer in-situ operation that started after 2013 and is in the pre-payout royalty phase, which results in lower operating costs and lower sustaining capital costs. The high-cost asset represents an older in-situ asset, or a mining project, that generally has higher operating and sustaining capital costs.

Project economic inputs such as operating expenses, royalty payments, sustaining capital costs, and received prices relative to market prices are based on corporate annual information forms and management discussion analysis for 2022 and 2023 operating oil sands assets.

Oil Sands CCS Capital Cost Assumptions

To materially reduce emissions for these representative assets, the financial implications of implementing CCS is then analyzed. We estimate that these representative oil sands assets would need to incur a capital expenditure (Capex) of $2.2 billion to implement CCS. This Capex cost includes outlays for capture, processing equipment, and other expenses to enable capture operations. The estimates for Capex are based on historical projects, publicly available papers, and validation from subject matter experts. For instance, the Quest project, which can sequester one million tonnes of emissions per year, cost $1.3 billion. We estimate that current costs would be around 30% lower compared to when Quest was financed.[7]

Capital costs paid by the producer in the representative model are adjusted to account for the federal Investment Tax Credit (ITC), which provides a 50% subsidy for capture equipment. Capital costs are also adjusted to account for the Alberta Carbon Capture Incentive Program (ACCIP), which provides a 12% grant for eligible CCS capital costs. Based on our understanding of the intended purpose of ACCIP, we treat these incentives as fully additive and calculate the amounts returned to producers from total project costs.

We estimate that oil sands assets incur annual operating costs of $110 per tonne of emissions abated. Opex includes annual expenses for maintenance, electricity, and chemicals required for operating the capture technology. It also includes costs for transport and storage, as we assume the operator pays these costs to a third-party provider of transport and storage services. The assumptions for Opex are based on estimates of operation and maintenance costs from the National Energy Technology Laboratory, as well as transport and storage costs from Canada's Carbon

[7] Shell unveils new carbon capture project amid wave of new CCS proposals in Alberta, CBC, Source: https://www.cbc.ca/news/business/shell-carbon-capture-alberta-government-1.6099797#:~:text=Quest%20cost%20%241.3%20billion%20to%20build%20and%20is,to%20the%20annual%20emissions%20of%20about%20250%2C000%20cars

Management Strategy.[8,9] By considering these Capex and Opex costs, we can assess the economic feasibility of implementing carbon capture and storage technology for oil sands operations.

Figure 15: Capital Costs of Representative CCS Project[10]

Millions	Total	ACCIP	ITC	Net Cost
Capture costs	1,747	(210)	(874)	663
Other	437	0	0	437
Total	**2,184**	**(210)**	**(874)**	**1,101**

Note: Values may not add due to rounding

Our definition of current policy

The two representative projects need to make several assumptions about future policy. The primary policy instruments are the industrial carbon taxation system within Alberta, carried out through the Technology Innovation and Emissions Reduction (TIER) regulation, the future evolution of the proposed Cap and the extent to which producers can monetize carbon credits.

TIER is important because the avoidance of the carbon tax represents an incentive to invest in CCS. Here we make two assumptions which we judge to be roughly offsetting. First, we assume that the representative assets do not reduce their compliance obligation costs over time through the efficiency improvements included in our BUA emissions forecast. Second, we assume that producers make no assumption related to the potential future tightening of TIER after 2030.[12] We assume that the TIER system remains structured as per Figure 16. Later in this report we discuss the results of a sensitivity analysis that considers changes to the TIER benchmark.

The analysis makes no assumption about the evolution of the proposed Cap after 2030. We assume that the cap remains at 137Mt CO2e for consistency with the other current policy assumptions.

Finally, in our core scenarios we assume that operators cannot monetize carbon credits generated through TIER. This is because in a net-zero scenario most operations will need to decarbonize, effectively creating an oversupply of credits that drives prices very low. Nevertheless, we test the carbon credit price assumption in the sensitivity analysis and find that it does not change the results.

[8] Cost of Capturing CO2 From Industrial Sources, National Energy Technology Laboratory, Source: https://www.netl.doe.gov/projects/files/CostofCapturingCO2fromIndustrialSources-011014.pdf

[9] Canada's Carbon Management Strategy, Government of Canada, Source: https://natural-resources.canada.ca/climate-change/canadas-green-future/capturing-the-opportunity-carbon-management-strategy-for-canada/canadas-carbon-management-strategy/25337#a2

[10] Actual Capex and Opex costs will vary based on facility size, proximity to storage, and purity of carbon stream. We outline a representative Opex and Capex cost.

Figure 16: TIER Assumption Breakdown

Year	Taxed Emissions	Tightening Rate[11]	Effective Emission Benchmark	Carbon Tax Schedule ($/tonne)	Effective Carbon Price[13] ($/bbl)
2019	0%	0%	0%		0.00
2020	10%	0%	90%	40	0.29
2021	11%	1%	89%	40	0.32
2022	12%	1%	88%	50	0.43
2023	14%	2%	86%	65	0.66
2024	16%	2%	84%	80	0.92
2025	18%	2%	82%	95	1.23
2026	20%	2%	80%	110	1.58
2027	22%	2%	78%	125	1.98
2028	24%	2%	76%	140	2.42
2029	28%	4%	72%	155	3.12
2030	32%	4%	68%	170	3.92
2031	32%	0%	68%	170	3.92
2032	32%	0%	68%	170	3.92
2034	32%	0%	68%	170	3.92
2035	32%	0%	68%	170	3.92
2036	32%	0%	68%	170	3.92
2037	32%	0%	68%	170	3.92
2038	32%	0%	68%	170	3.92
2039	32%	0%	68%	170	3.92
2040	32%	0%	68%	170	3.92

iii. Cash Flow Projections

Base Forecast Assumptions

Both assets are assumed to produce about 100,000 barrels of oil per day. These assets are forecast to emit 3Mt of emissions annually, based on the 2021 average emissions intensity for oil sands. Revenues of the two assets are the same, as we assume that they both receive the forward price of oil of $60 per barrel (Figure 17), with the same adjustments to received price for transportation and heavy oil differential. However, due to differences in cost

[13] Effective carbon price on a $/bbl basis is calculated using the 0.072 tonne/bbl emissions intensity for oil sands in 2021

structure, the low-cost asset earns $13.94 in net income per barrel produced, while the high-cost asset earns $0.85 per barrel produced over a future period between 2024 and 2040.[12] The same emissions intensity has been used for the low-cost and high-cost assets as a simplifying assumption due to the lack of data available related to emissions intensity for low-cost and high-cost assets. There are likely differences in emissions intensity between these two asset types with a high-cost asset potentially requiring more steam and therefore generating more emissions associated with operations.

Figure 17: Average WTI Forward Curve for Prior 30-day Period[13]

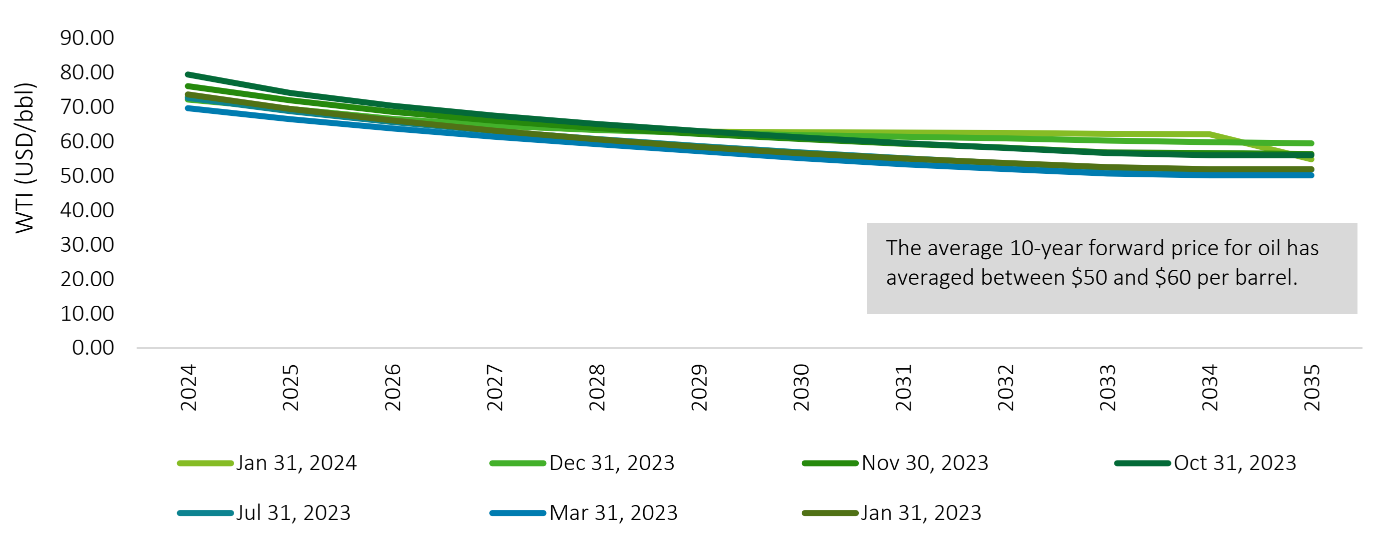


Figure 18: Representative Assets – Input Assumptions

	Low-Cost Asset	High-Cost Asset
Oil Production (bbl/d)	100,000	100,000
Emissions (tonnes/year)	3,000,000	3,000,000
WTI Oil Price (USD/bbl)	60.00	60.00
Revenue ($/bbl)[14]	42.50	42.50
Expenses ($/bbl)[15]	(24.40)	(41.40)

Figure 19 outlines the cash flow components for the representative assets from 2024 to 2040 using the above assumptions for the base forecast. In addition to the inputs above, the cash flow projections assume the following:

- The projections are calculated in real dollars.
- The operating expenses include TIER payments in line with those outlined in Figure 18 above. The potential to avoid this cost ($2.2 billion over the 16- year period) would represent a benefit of the investment.
- Income taxes are assumed to be paid at a rate of 23%, which includes both federal and provincial taxes, with no tax shield assumed for the assets.

[12] Note: Unless otherwise specified, all amounts in this report are denominated in Canadian Dollars.
[13] Data source for forward curve data is from CME Group
[14] Revenue is net of a heavy oil differential, blending costs, and transportation.
[15] Expenses includes operating costs, royalties, and sustaining capital to maintain the estimated production per year.

- A discount rate of 10% is used as a proxy for the weighted average cost of capital (WACC) in a typical business-as-usual scenario. This rate is representative of a reasonably certain stream of revenue within the oil and gas sector.
- As seen below (Figure 19), the low-cost asset has a discounted value of $4.6 billion, while the high-cost asset has a discounted value of $401 million.

Figure 19: Cash Flow – Base Forecast, Total for 2024 - 2040 Period

	Low-Cost Asset	High-Cost Asset
Revenue ($million)	**26,371**	**26,371**
Expenses ($million)	**(15,140)**	**(25,688)**
Opex ($million)	(6,826)	(11,169)
Royalties ($million)	(1,086)	(2,947)
Sustaining Costs ($million)	(4,964)	(9,308)
Carbon tax ($million)	(2,264)	(2,264)
EBITDA ($million)	**11,231**	**683**
Taxes ($million)	(2,583)	(158)
Net income ($million)	**8,648**	**528**
Investment ($million)	-	-
Cashflow ($million)	**8,648**	**528**
Discounted cashflow - 10% WACC ($million)	**4,617**	**401**
Cashflow ($/bbl)	**13.94**	**0.85**

CCS Investment Assumptions

To consider the investment in CCS by the producer for these representative assets, we developed similar cash-flow forecasts, incorporating the costs of implementing the technology. Figure 20 outlines the cash flow components for the representative assets from 2024 to 2040. In addition to the base assumptions listed in Figure 18, which do not change, the cash flow projections assume the following:

- Implementation of CCS will begin in year 3 (2026) with capital spent to implement the technology in the prior year.
- The carbon capture rate is 80%, which means that no carbon tax will be paid after its implementation.
- No value has been attributed to carbon credits generated through the TIER program.
- The investment cost shown in Figure 20 represents the net cost to implement CCS technology for the producer after ITC and ACCIP deductions.
- Depreciation is calculated at 8% per year for the CCA balance, with the initial balance based on the net cost to the producer for implementing CCS.
- A discount rate of 15% has been used, which serves as a proxy to represent a higher expected weighted average cost of capital (WACC). This rate is representative of higher risk stream of revenue associated with large scale investment in a relatively new technology.

As seen below (Figure 20), the CCS investment results in an asset value of $2.5 billion for the low-cost producer, which is still profitable but results in a lower asset value than the BAU case. For a high-cost producer the net value of the asset after accounting for CCS costs is significantly negative (-$906 million). CCS investment entails a negative ROI regardless of the type of oil sands asset.

Figure 20: Cash Flow – Production with CCS, Total for 2024 - 2040 Period

	Low-Cost Asset	High-Cost Asset
Revenue ($million)	**26,371**	**26,371**
Expenses ($million)	**(16,911)**	**(27,459)**
Opex ($million)	(6,826)	(11,169)
Royalties ($million)	(1,086)	(2,947)
Sustaining Costs ($million)	(4,964)	(9,308)
Carbon tax ($million)	(90)	(90)
CCS Opex ($million)	(3,946)	(3,946)
Carbon credit ($million)	-	-
EBITDA ($million)	**9,461**	**(1,088)**
Taxes ($million)	(2,357)	(59)
Depreciation ($million)	786	786
Net income ($million)	**7,890**	**(361)**
Investment ($million)	(1,101)	(1,101)
Cashflow ($million)	**6,789**	**(1,462)**
Discounted cashflow - 15% WACC ($million)	**2,447**	**(906)**
Cashflow ($/bbl)	**10.94**	**(2.36)**

Production Curtailment Assumptions

In this section we consider the financial implications of meeting the proposed Cap by curtailing production instead of investing in CCS technology. We calculate that producers will be required to reduce emissions by 30% in 2030, assuming no reduction in emissions have occurred between 2021 and 2030 for these assets, to meet the emission reduction requirement of the proposed Cap. Moreover, this assumption means that the oil sands would bear the full burden of the adjustment to the proposed Cap. It is difficult, at this point, to determine how the reduction will be applied across the various producers within the sector, however it is quite plausible that instead of the 30% production curtailment posited in our analysis, oil sands production curtailment would be closer to 15%. This means that the loss of value due to production curtailment estimated in this study is likely an upper bound estimate.

Figure 21 outlines the cash flow components for the representative assets from 2024 to 2040 for production curtailment to operations. The following is a summary of assumptions used in the analysis.

- We assume that the curtailment of production will have no negative consequences to overall reservoir performance and that the asset can maintain production at the reduced level for the remainder of the projection period.

- Operating costs and sustaining capital costs are increased on a per barrel basis by 20% once production decreases to account for reduced operational efficiency with a lower production base.
- A discount rate of 10% is used as a proxy for the weighted average cost of capital (WACC) in a typical business-as-usual scenario. This rate is representative of a reasonably certain stream of revenue within the oil and gas sector. This is the same as the base forecast assumption as the asset operations have not changed in the technology or risk profile.
- In this scenario the low-cost asset has an economic value of $3.6 billion. The high-cost asset has an economic value of $440 million.

Figure 21: Cash Flow–Production Curtailment, Total for 2024 - 2040 Period

	Low-Cost Asset	High-Cost Asset
Revenue ($million)	**20,528**	**20,528**
Expenses ($million)	**(12,751)**	**(21,701)**
Opex ($million)	(5,894)	(9,644)
Royalties ($million)	(845)	(2,294)
Sustaining Costs ($million)	(4,286)	(8,037)
Carbon tax ($million)	(1,726)	(1,726)
CCS Opex ($million)	-	-
Carbon credit ($million)	-	-
EBITDA ($million)	**7,776**	**(1,174)**
Taxes ($million)	(1,789)	(131)
Depreciation ($million)	-	-
Net income ($million)	**5,988**	**(1,305)**
Investment ($million)	-	-
Cashflow ($million)	**5,988**	**440**
Discounted cashflow – 10% WACC ($million)	**3,641**	**369**
Cashflow ($/bbl)	**9.65**	**0.71**

iv. Producer Reaction to the Cap and implications for oil and gas output

The cash flow analysis is summarized in Figure 22. As shown, implementing CCS would render high-cost assets economically unviable. Low-cost assets would remain economically viable even after investing in CCS. Nonetheless, curtailing production would be a more cost-effective option compared to investing in CCS. Hence, the most likely outcome is that producers would opt to curtail production if confronted with the proposed Cap in 2030.

Figure 22: Discounted Cashflow Comparison for Low-Cost and High-Cost Assets

Discounted cashflow ($million)		
	Low-Cost Asset	High-Cost Asset
Base Forecast (10% WACC)	4,617	401
Production with CCS (15% WACC)	2,447	(906)
Production curtailment (10% WACC)	3,641	369
Production curtailment vs CCS	1,194	1,275

In addition to the quantified factors considered within the cash flow analysis, there are other important factors that support the investment conclusion but have not been fully quantified. These factors include:

- Cost Uncertainty: CCS entails significant cost uncertainty related to factors such as technology development, construction, and regulatory processes. While we assumed swift implementation within the cash flow timeframe, potential regulatory and construction delays could impact the project's financial feasibility. These costs significantly influence the viability of CCS investments.
- Policy Framework: The existing and future policy framework surrounding CCS plays a vital role in its feasibility and profitability. Uncertainty regarding policies beyond 2030 acts as a significant barrier to investment.
- Oil Prices: Fluctuations in oil prices can also impact the financial viability of oil sands assets and associated major investments such as CCS implementation. While we have assumed a $60/bbl long-term price, lower long-term prices would further undermine CCS financials.

Furthermore, it is important to note that once implemented, the investment in CCS is irreversible. However, production curtailment can be reversed. Considering these factors, we do not foresee any oil-sands CCS investments being implemented.

v. Impact of Producer Reaction

Meeting the Cap obligations through production curtailment suggests that Canada would need to reduce total oil production by approximately 626 thousand barrels per day, or about 10% compared to BAU production in 2030 (Figure 23). Additionally, Canada would need to reduce gas production by approximately 2.2 billion cubic feet per day, equivalent to a 12% reduction in production volumes relative to BAU production in 2030.

From 2030 to 2040, we assume that the Cap will remain at 137Mt CO_2e, thereby limiting the emissions level in the sector during this period. While the sector can still experience growth, it will be constrained compared to the baseline scenario growth forecast.

We consider this conclusion to be a best-case scenario. In particular, the assumption that producers in the sector have access to 25MT of offsets is likely optimistic. If access to offsets were lower, the Cap would require a larger reduction in production.

Figure 23: Total Canada Production Curtailing[16]

	Emissions Level 2030 (Mt CO2e)	Forecasted Decrease in Production in 2030
Canada	**157.0**	
Total Oil	**116.3**	**-626,400 b/d**
Conventional Oil Production	24.6	-214,600 b/d
Oil Sands	91.7	-411,800 b/d
In situ bitumen	55.4	-205,100 b/d
Mined bitumen	36.4	-206,600 b/d
Conventional Gas	**40.6**	**-2.2 Bcf/d**

Provincial Implications

The allocation of production curtailment among provinces is determined by considering the respective contributions of industrial and provincial shares of emissions generated by upstream oil and gas sector producers in 2022. Figure 24 illustrates the anticipated decrease in production in Canada's most oil and gas-intensive provinces. Given its significant share of production, Alberta is expected to bear most of the production cuts, accounting for approximately 86% of the emissions gap reduction through production curtailment. This reduction is estimated to amount to approximately 526 thousand barrels per day, equivalent to a 10% decrease in production volume compared to the BAU scenario.

The production curtailment reduction outlined in Figure 24 serves as an input to the CGE model to carry out the second part of our analysis: the economic impact of the Cap to the economy.

[16] We assume the legal upper bound of the Cap remains constant between 2030 and 2040. In practice the legal upper bound is expected to decrease over time to reach net zero by 2040.

Figure 24: Emissions and Production Forecast by Province

	Emissions Level 2030 (Mt CO2e)	Decrease in Production	Percentage Difference: 2030 BAU Production vs Decrease in Production
Alberta	**134.5**		
Total Oil	105.9	-526,000 b/d	-10%
Conventional Oil Production	14.2	-114,300 b/d	-8%
Oil Sands	91.7	-411,800 b/d	-11%
In situ bitumen	55.4	-205,100 b/d	-10%
Mined bitumen	36.4	-206,600 b/d	-12%
Conventional Gas	28.6	-1.37 Bcf/d	-16%
BC	**11.4**		
Conventional Oil Production	0.5	-14,600 b/d	-6%
Conventional Gas	10.9	-0.77 Bcf/d	-9%
Newfoundland and Labrador	**1.0**		
Conventional Oil Production	1.0	-26,200 b/d	-7%
Saskatchewan	**9.6**		
Conventional Oil Production	8.5	-54,300 b/d	-10%
Conventional Gas	1.1	0.04 Bcf/d	-11%

vi. CCS Investment Sensitivity Analysis

In this section, we examine the sensitivity of our CCS cash flow analysis to the following assumptions:

- The price of oil;
- Introduction of carbon credit value to the investment analysis;
- The magnitude of the production curtailment required in the oil sands

By conducting this sensitivity analysis, we aim to ensure that our results regarding CCS are reasonably robust.

The impact of oil price fluctuations, for example, can significantly influence the economic viability of oil projects and therefore CCS investments. Changes in regulation and policies, on the other hand, can introduce new incentives or barriers for the adoption and implementation of CCS technologies. Additionally, the choice of discount rates can have a substantial impact on the economic evaluation of CCS projects over the long term.

By examining the sensitivity of CCS investment to these factors, we can gain a comprehensive understanding of the potential challenges and opportunities associated with this investment. This analysis allows us to understand the potential range of our results and ensure that we are confident in the potential contributions of CCS towards achieving emissions reduction targets.

Oil Price

The decision for producers to make significant investments in their assets, such as CCS, is influenced by external market factors such as the long-term oil price. We have prepared sensitivities reflecting a WTI oil price of $75 USD/bbl and $50 USD/bbl to demonstrate the impact this would have on the likelihood of considering a large-scale investment. In both of these oil price scenarios, the difference between the market price (WTI) and the received price was kept constant with the $60 USD/bbl scenario used in the above sections in order to demonstrate changes in revenue that are not within the control of the producer.

As shown in Figure 25 and Figure 26, the price of oil plays a significant role in producer decisions. At an oil price of $75 per barrel, both low-cost and high-cost producers find their operations more economically viable. However, even in this scenario, it is still more profitable for a producer to curtail production rather than implementing CCS. On the other hand, at an oil price of $50 per barrel, the operations of the representative high-cost asset is no longer economically viable as it is assumed the same cost structure for the asset is maintained.

On balance, we expect that producer considerations related to the price of oil would reinforce the conclusion in this report that the optimal financial strategy for meeting the Cap is to curtail production.

Figure 25: Oil Price ($75 bbl)

Discounted cashflow ($million)	Low-Cost Asset	High-Cost Asset
Base Forecast (10% WACC)	8,708	4,493
Production with CCS (15% WACC)	5,672	2,350
Production curtailment (10% WACC)	7,092	3,328
Production curtailment vs CCS	1,420	978

Figure 26: Oil Price ($50 bbl)

Discounted cashflow ($million)	Low-Cost Asset	High-Cost Asset[17]
Base Forecast (10% WACC)	1,889	-
Production with CCS (15% WACC)	297	-
Production curtailment (10% WACC)	1,340	-
Production curtailment vs CCS	1,043	-

Carbon Credit Value

Carbon credit value could be a financial benefit to CCS investments; however, we did not ascribe value to carbon credits in our analysis of CCS investment. This is because it is difficult foresee that demand for credits will be sufficient to maintain prices at material levels in a scenario where the sector moves to net zero emissions. To test this

[17] The cash flow model assumes that when the cash flow for the asset is negative (excluding investment costs) production will cease rather than continue to incur negative cash flow. Due to this model design, no value is attributed to the high-cost asset at an oil price of $50/bbl for any of the options assessed.

assumption, we include sale of carbon credits at a price of $150 per tonne. The carbon credit value of $150 per tonne is likely optimistic as it reflects a minor discount to the $170 per tonne statutory carbon price. Even with this assumption, both low-cost producers and high-cost producers would still prefer to curtail production rather than implementing CCS (Figure 27).

Figure 27: Oil Price ($60 bbl), Carbon Credit Value = 150 $/tonne

Discounted cashflow ($million)		
	Low-Cost Asset	High-Cost Asset
Base Forecast (10% WACC)	4,617	401
Production with CCS (15% WACC)	3,370	47
Production curtailment (10% WACC)	3,641	369
Production curtailment vs CCS	271	322

Magnitude of Production Curtailment

It is difficult, at this point, to determine how a production curtailment to achieve the emissions reductions needed will be applied across the various producers within the sector. However, it is equally likely that the production curtailment required will be closer to 15% as our base estimate of 30%. Therefore, we have prepared a sensitivity reflecting a lower magnitude of production curtailment than our base case. We observe that with this assumption, both low-cost producers and high-cost producers would still prefer to curtail production rather than implementing CCS (Figure 28).

Figure 28: Oil Price ($60 bbl), Production Curtailment = 15%

Discounted cashflow ($million)		
	Low-Cost Asset	High-Cost Asset
Base Forecast (10% WACC)	4,617	401
Production with CCS (15% WACC)	2,447	(906)
Production curtailment of 15% (10% WACC)	4,003	369
Production curtailment vs CCS	1,556	1,275

3. Economic Impact of the Cap

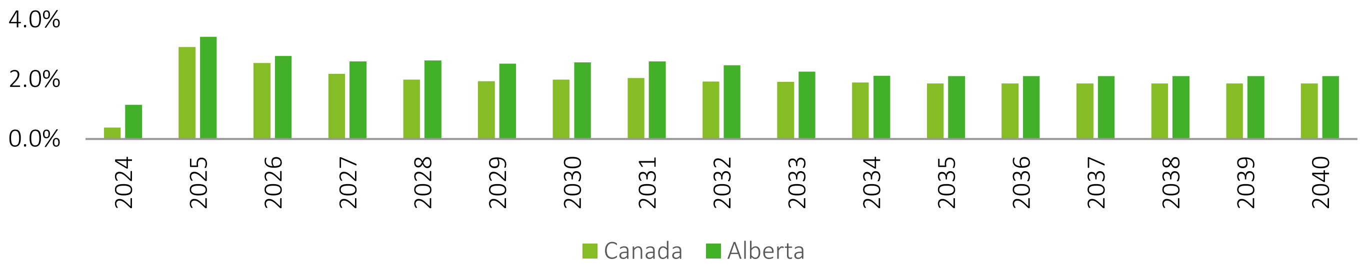
i. Baseline Economic Scenario

The economic impact of the Cap is measured by comparing the economic outcome under the Policy scenario (economy under the Cap) to the Baseline scenario (without the Cap). The Baseline scenario reflects Deloitte's economic forecast for Canada at both the national and provincial level.

In the Baseline scenario, Alberta's economic growth is forecasted to average 2.3% over the 2024-2040 period, exceeding the average growth rate of Canada (Figure 29). Alberta's labour force is also expected to grow faster than the labour force of Canada, 1.8% versus 1.0% on average (Figure 30).

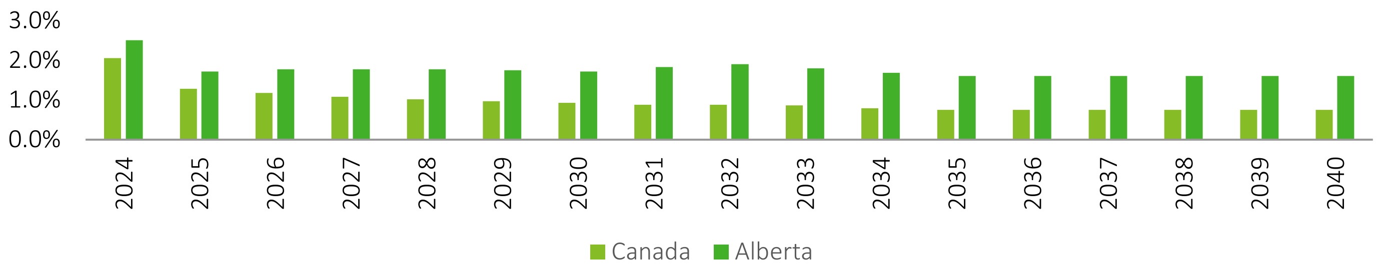
The oil and gas sector in Alberta is forecasted to grow by 2.7% in 2024 compared to 2023 and then accelerate to 6.1% in 2025. Most of the growth of the sector in Alberta, however, is front-end loaded, with annual growth rates expected to slow down to 1.2-1.4% by 2027 (Figure 31). Canada's oil and gas sector follows a similar trend, forecasted to grow by 2.6% in 2024 compared to 2023 and then accelerate to 6.0% in 2025. Between 2030 and 2040, Canada's oil and gas sector is forecasted to grow on average at 1.0% annually.

Figure 29: Real GDP Growth, Alberta and Canada, Annual Growth Rate, 2024 - 2040



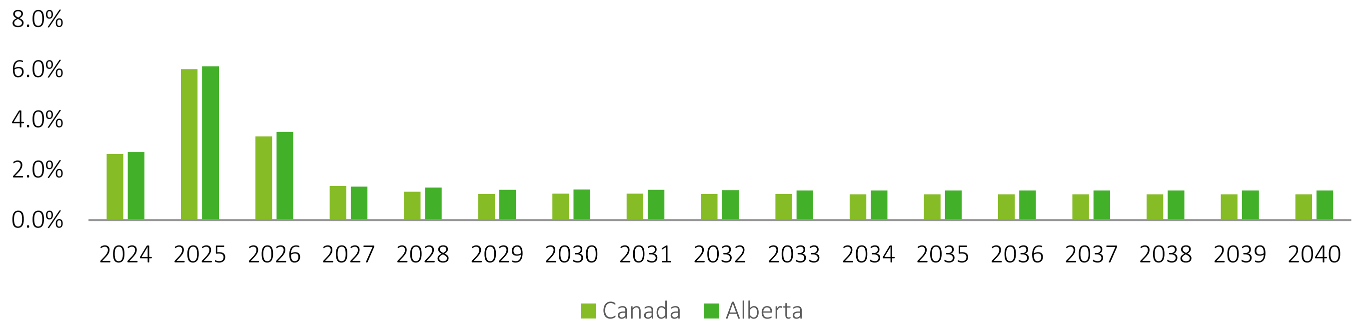
Sources: Deloitte forecast

Figure 30: Labour Force Growth, Alberta and Canada, Annual Growth Rate, 2024 - 2040



Source: Deloitte forecast

Figure 31: Oil and Gas Output Growth, Annual Growth Rate, 2024 -2020



Source: Deloitte forecast

ii. Summary of Findings

Cap's Impact on Canada's Oil and Gas Sector

The Policy scenario is defined based on the expected production curtailment in the upstream oil and gas sector to meet the 20 Mt CO2e reduction required under the Cap. This translates into a 10% reduction in total oil production and a 12% reduction in total gas production in Canada in 2030 compared to 2030 levels under the baseline. As outlined on Figure 3, the expected reduction in production by 2030 breaks down as follows:

- A 10% reduction in oil production and a 16% reduction in gas production in Alberta;
- A 6% reduction in oil production and a 9% reduction in gas production in British Columbia;
- A 7% reduction in oil production in Newfoundland and Labrador;
- A 10% reduction in oil production and 11% reduction in gas production in Saskatchewan.

In Canada, the sector is projected to experience a growth rate of 0.27% on average between 2031 and 2040 under the Cap, whereas under the baseline the sector is projected to experience an average growth rate of 1.0%.

As a result of the Cap, GDP in Alberta's oil and gas sector is projected to be $16.2 billion (20%) lower compared to the baseline in 2040 (Figure 32). On average, the sector's GDP is estimated to be 16% lower compared to the baseline between 2030 and 2040. In the Rest of Canada, GDP in the sector is projected to be $2.7 billion lower by 2040, compared to the baseline. On average, GDP in the oil and gas sector in the Rest of Canada is estimated to be 11% lower compared to the baseline between 2030 and 2040. Because the Cap is a permanent measure, the shift in the output of the oil and gas sector and associated losses are permanent as well and accumulate over time (Figure 33).

Figure 32: Oil and Gas Sector: Deviation in Real GDP, Policy vs Baseline, $B (2017 dollars)

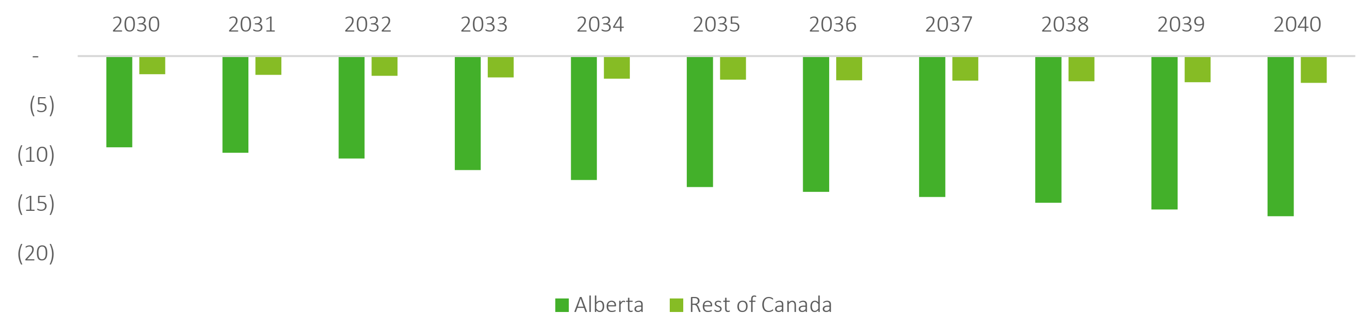
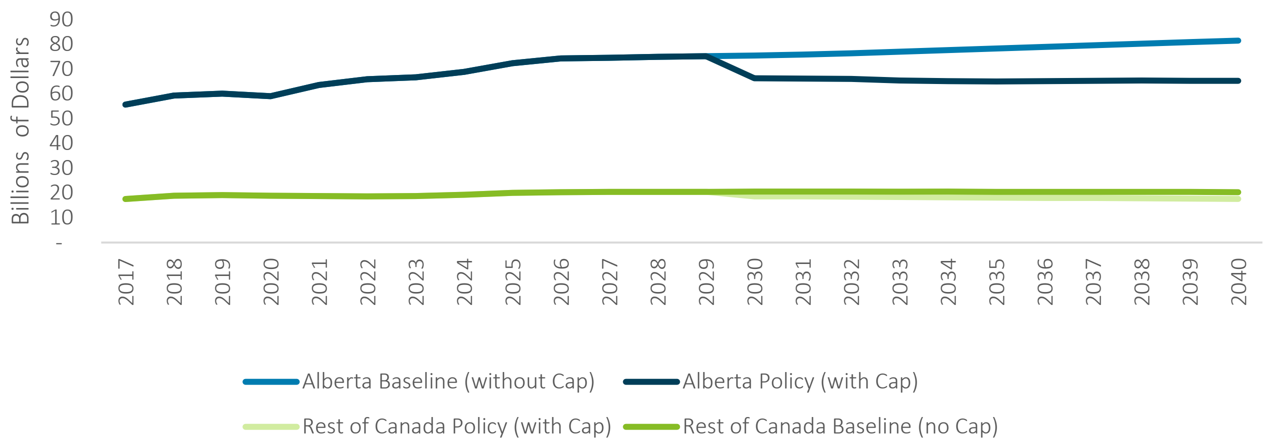


Figure 33: Oil and Gas Sector, Real GDP under Policy, and Baseline, $B (2017 dollars)



Cap's Impact on Other Sectors

Production curtailment in the oil and gas sector will impact other sectors in Alberta and in the Rest of Canada through several channels. On the one hand, the negative impact will be transmitted through the operations of the supply chains as the oil and gas sector demands fewer intermediate inputs from suppliers in Alberta and in other provinces. The increase in the oil price associated with the cut in production will also hit other sectors, increasing the cost of their production. At the same time, other sectors can benefit from exchange rate depreciation and lower wage rates that will help reallocate labour from the oil and gas sector to other employers and ultimately balance the labour market.

Alberta's oil and gas sector's top domestic inputs include supporting activities, architectural, engineering, and related services, wholesalers, and electric power generation (Figure 34). These sectors will be directly impacted by lower oil and gas production. Supply chain impacts are not limited to the provinces that are primary producers of oil and gas. Many intermediate inputs are purchased from other provinces (Figure 35). Alberta's oil and gas sector imports primarily from Ontario, British Columbia, and Quebec. For example, Alberta's oil and gas sector imports financial and banking services from Ontario and computer systems and design from British Columbia.

Under the Cap, all sectors are expected to lose except for manufacturing in Alberta and the Rest of Canada (Figure 36 and Figure 37). Mining, refinery products, and utilities are expected to experience a decrease in real output both in Alberta and the Rest of Canada as those sectors are closely connected to the oil and gas sector. The services sector, which is part of the oil and gas supply chain, will also be negatively affected. Services are mostly non-tradable therefore they do not benefit from currency depreciation, and at the same time they are hit by lower domestic demand from households and businesses.

At the same time, the manufacturing sector experiences growth under the Cap (Figure 36 and Figure 37). This growth is primarily driven by an increase in exports, which is stimulated by the depreciation of the Canadian dollar. In Alberta, the manufacturing sector (excluding refineries) is export-oriented and on average ships 61% of its output to other provinces or countries, and under the Cap the sector's GDP is projected to increase by 5% compared to the baseline.[18]

[18] Calculated using values from Statistics Canada Provincial Symmetric Input-Output Tables, 2019, Alberta.

Figure 34: Top Domestic Inputs of Alberta's Oil and Gas Sector[19]

	Supply ($M)
Support activities for oil and gas extraction	6,258
Architectural, engineering, and related services	2,264
Electric power generation, transmission, and distribution	1,291
Machinery and equipment wholesalers	1,236
Petroleum refineries	963
Waste management and remediation services	941
Repair construction	858
Truck transportation	793
Banking and other depository credit intermediation	784
Management, scientific and technical consulting services	745

Figure 35: Top Inter-Provincial Imports of Alberta's Oil and Gas Sector[20]

	Supply ($M)
Computer systems design and related services	634
Holding companies	593
Financial investment services, funds, and other financial vehicles	545
Machinery, equipment and supplies merchant wholesalers	476
Architectural, engineering, and related services	467
Support activities for transportation	383
Employment services	342
Insurance carriers	284
Banking and other depository credit intermediation	260
Petroleum refineries	220

[19] Statistics Canada. Provincial Symmetric Input-Output Tables, 2019, Alberta.
[20] Statistics Canada. Provincial Symmetric Input-Output Tables, 2019, Alberta.

Figure 36: Change in Real Output, Policy vs Baseline, Alberta, 2040 (%)

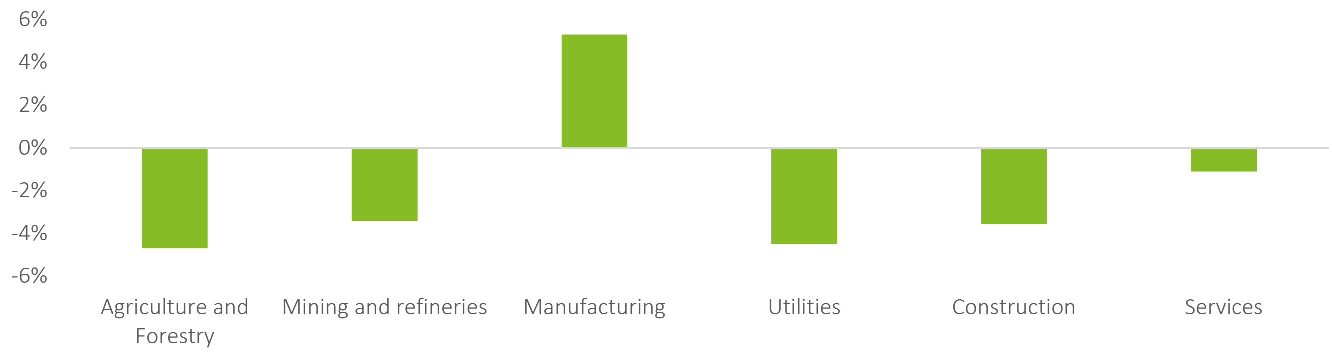
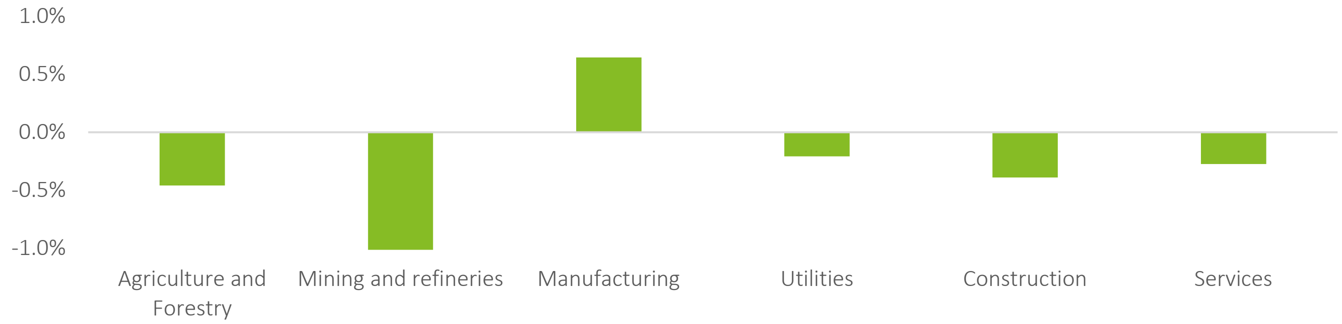


Figure 37: Change in Real Output, Policy vs Baseline, Rest of Canada, 2040 (%)



Economy-Wide Impacts

The production curtailment resulting from the implementation of the Cap has a ripple effect throughout the economy. By 2040, it is estimated that Alberta's real GDP will be 4.5% lower compared to the baseline scenario. Cumulatively, over the 2030 to 2040 period, it is estimated that GDP in Alberta is $191 billion lower compared to the baseline ($2017 dollars). This significant decrease reflects the permanent economic downturn caused by the decline of the oil and gas sector as shown in Figure 39.

The GDP for the Rest of Canada is expected to be $91 billion lower over the same period compared to the baseline, indicating that the rest of the country is not immune to the negative consequences ($2017 dollars). By 2040, Rest of Canada's GDP is projected to be 0.4% lower compared to the baseline scenario. In Ontario and Quebec, provinces that are not directly subject to the Cap, the GDP is lower by 0.2% and 0.1% respectively by 2040. The larger impact on the Ontario's economy is due to province's greater exposure to Western Canada – Alberta accounts for 23% of Ontario's interprovincial shipments, compared to 12% for Quebec.

Alberta is estimated to lose on average 55,000 jobs between 2030 and 2040 (Figure 40). As a result of lower employment opportunities 2,400 individuals are estimated to move from Alberta to other provinces annually, or 25,880 in total over the 2030-2040 period. The Rest of Canada experiences a smaller employment impact, approximately 35,000 jobs over the 2030-2040 period, with Ontario and Quebec losing on average 12,000 and 2,500 jobs respectively (Figure 41 and Figure 42).

Figure 38: Change in Real GDP, Policy vs Baseline, Alberta, and ROC, $B ($2017 dollars)

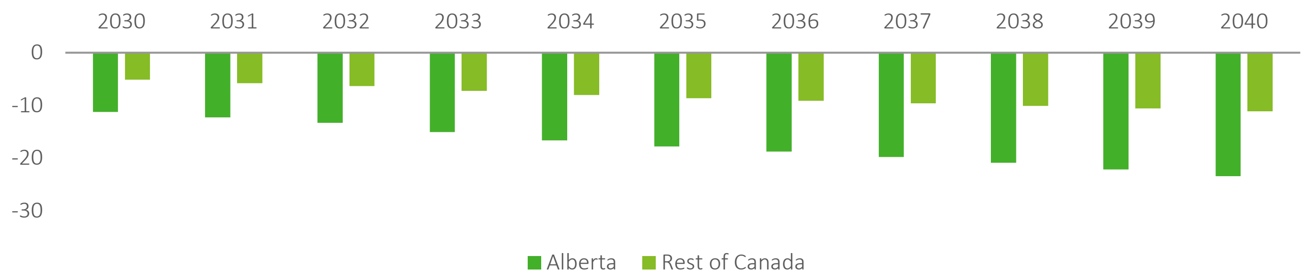


Figure 39: Real GDP under Policy and Baseline, Alberta, $B ($2017 dollars)

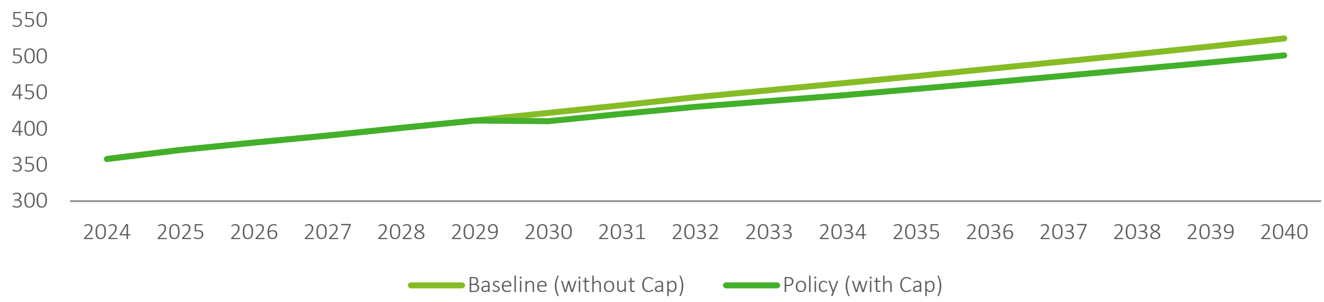


Figure 40: Change in Jobs, Policy vs Baseline, Alberta

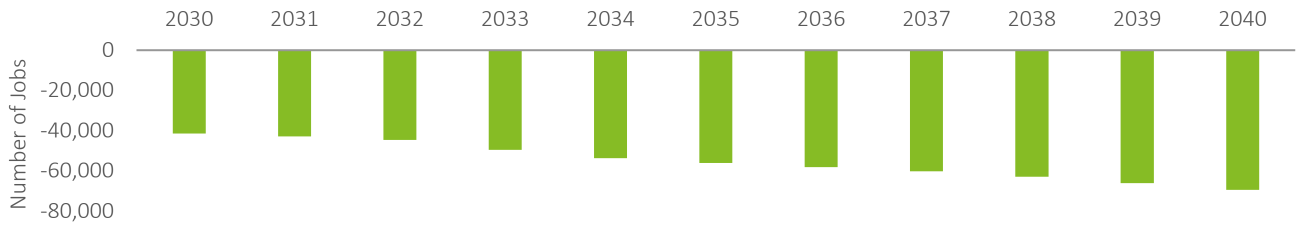
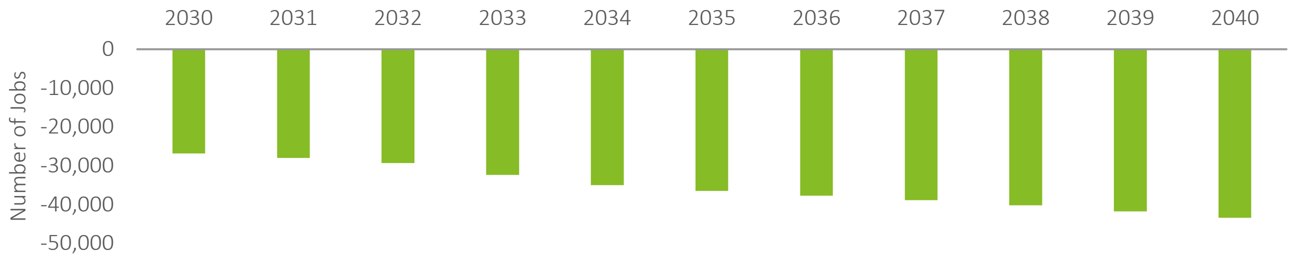


Figure 41: Change in Jobs, Policy vs Baseline, Rest of Canada



With fewer job opportunities available, the average real wage also decreases. In Alberta, the average real wage decreases by 2.2%, while in the Rest of Canada, it decreases by 0.2% compared to the baseline in 2040. This adjustment in the labor market, although facilitating the necessary transition, contributes to a decrease in household consumption outlined on Figure 42 as individuals have lower disposable income.

Another important consequence of the decline in the oil and gas sector is a reduction in the rate of return on investments. As a result, investments, including international investments, decrease in the economy (Figure 42). This decrease in investment activity has a ripple effect on various sectors and industries, contributing to the slowdown in the economic growth.

The exchange rate is estimated to depreciate by 2%, which facilitates the economic adjustment. The price of exports in terms of US dollars in most sectors decreases both in Alberta and in the Rest of Canada supporting an increase in exports. Despite that, total exports decline due to a decrease in exports of oil and gas, other minerals, and refineries.

In terms of Canadian dollars, the price of Alberta's exports increases under the Cap as a result of the direct and indirect impact of higher oil prices in Canada, however it increases less compared to the increase in price of imports. Alberta's terms of trade is estimated to be 1.3% lower compared to the baseline in 2040. In the Rest of Canada where the oil and gas sector is smaller and therefore the export price does not increase, the terms of trade deteriorates by 2%.

Finally, the decline in the oil and gas sector also has implications for government revenue. Government tax revenue decreases in line with decrease in GDP and prices. In Alberta, government tax revenue falls by 5.8% compared to the baseline in 2040. In addition, as a result of the Cap, royalties in Alberta are estimated to be 16% lower in 2040 compared to the baseline.

Figure 42: Macroeconomic Metrics: Policy vs Baseline, 2040

	Alberta	Rest of Canada	Canada
Oil and Gas Real GDP	-20%	-13.3%	-19%
Oil and Gas Real GDP (2017 Dollar, $B)	-16.2	-2.7	-18.9
Real GDP	-4.5%	-0.4%	-1.0%
Real GDP (2017 Dollar, $B)	-23.4	-11.1	-34.5
Real Investments	-3.6%	-0.5%	-1.0%
Real Household Consumption	-3.9%	-0.4%	-1.0%
Real Exports	-7.5%	-0.3%	-1.4%
Real Imports	-5.8%	-0.3%	-1.2%
Employment	-2.0%	-0.2%	-0.5%
Employment (Thousands)	-69.5	-43.4	-112.9
Real Wages	-2.2%	-0.2%	-0.5%
Exchange Rate (CAD/USD)	-2.0%	-2.0%	-2.0%
Price of Imports in CAD	1.9%	1.9%	1.9%
Price of Exports in CAD	0.5%	-0.1%	0.0%
Terms of Trade	-1.3%	-2.0%	-1.9%
Government Tax Revenues	-5.8%	-0.5%	-1.3%

Figure 43: Real GDP and Employment, Selected Provinces: Policy vs Baseline, 2040

	Alberta	Ontario	Quebec	British Columbia	Saskatchewan	Newfoundland and Labrador
Real GDP	-4.5%	-0.2%	-0.1%	-0.8%	-3.0%	-1.6%
Real GDP (2017 Dollar, $B)	-23.4	-2.3	-0.4	-4.0	-3.6	-0.5
Employment	-2.0%	-0.2%	-0.1%	-0.4%	-1.1%	-0.4%
Employment (Thousands)	-69.5	-15.1	-3.3	-13.9	-8.5	-0.9

Appendix A – Provincial Production and Unabated Emissions Forecast

Alberta Forecast

Figure 44: Alberta Conventional Oil Forecast

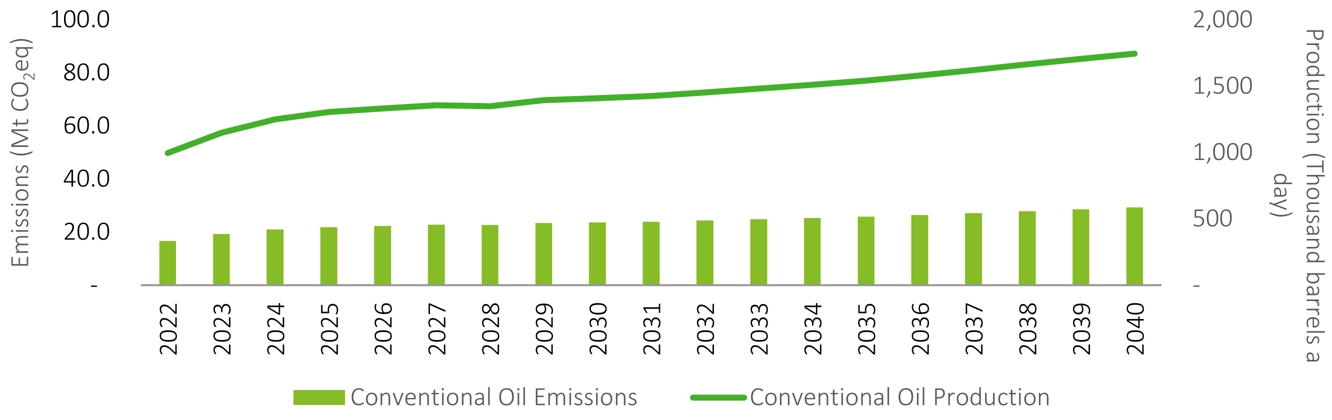


Figure 45: Alberta Oil Sands Forecast

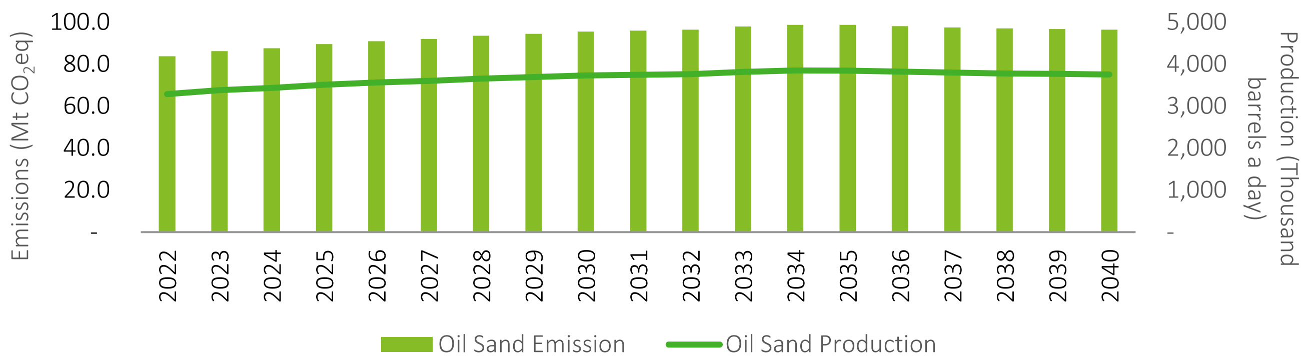
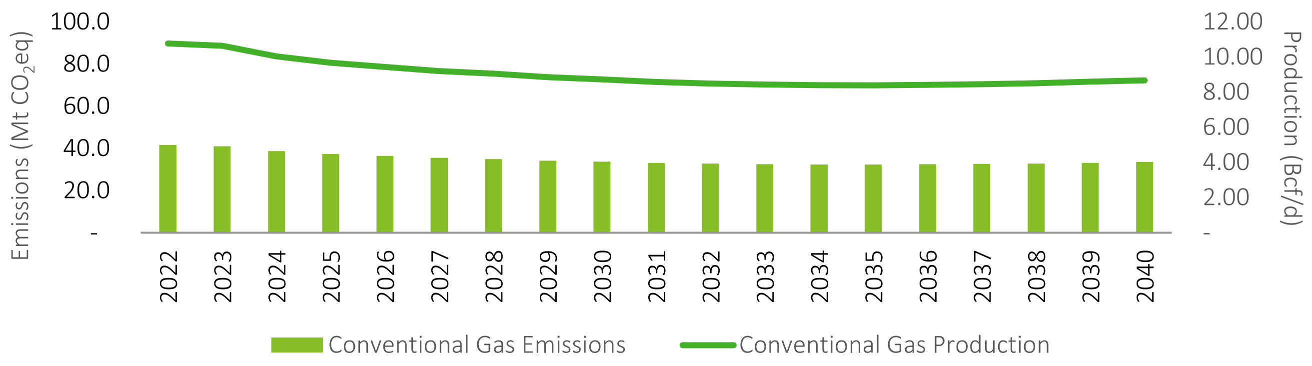
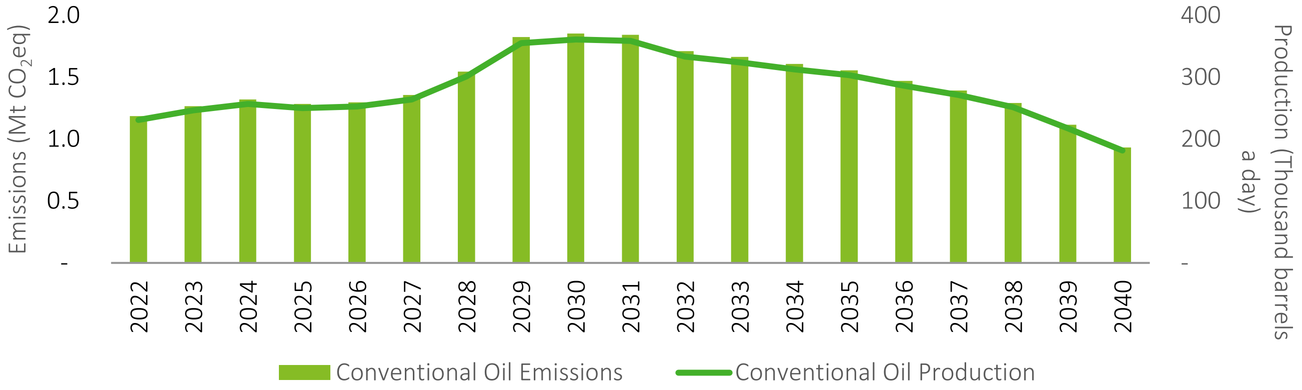


Figure 46: Alberta Conventional Gas Forecast



Newfoundland and Labrador Forecast

Figure 47: Newfoundland and Labrador Conventional Oil Forecast



British Columbia Forecast

Figure 48: British Columbia Conventional Oil Forecast

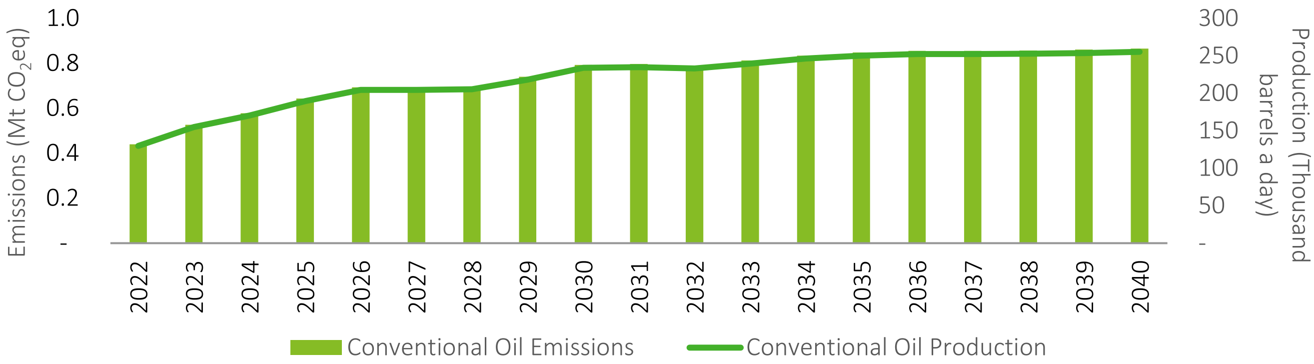
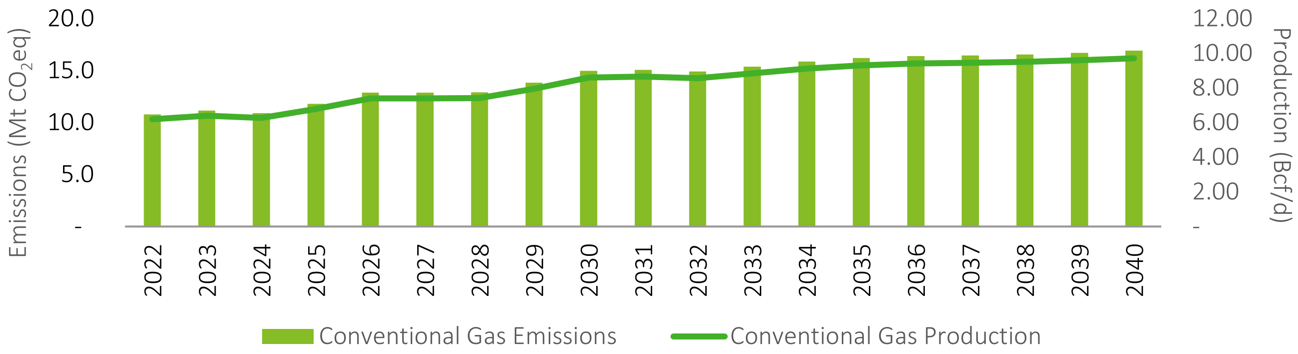


Figure 49: British Columbia Conventional Gas Forecast



Saskatchewan Forecast

Figure 50: Saskatchewan Conventional Oil Forecast

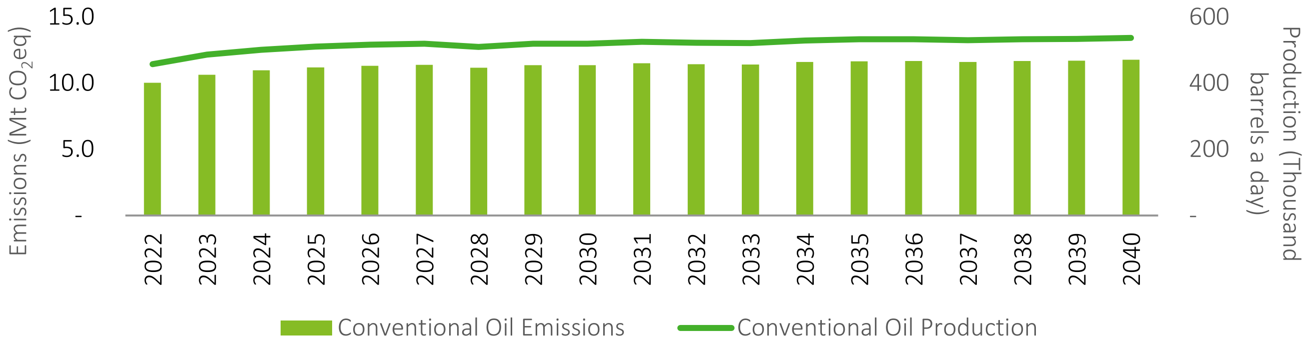
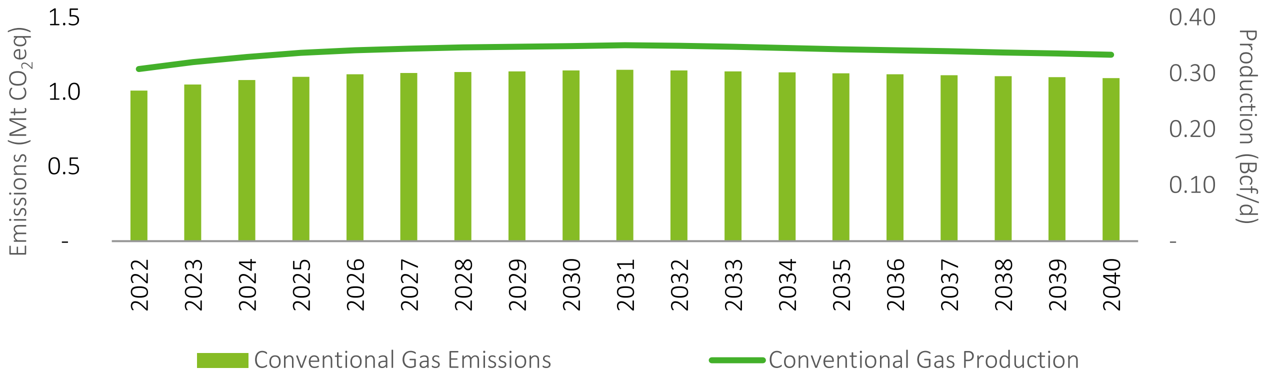


Figure 51: Saskatchewan Conventional Gas Forecast



Appendix B – Economic Impact per Year

Figure 52: Macroeconomic Metrics: Policy vs Baseline, Per Year, Alberta

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Oil and Gas Real GDP	-12.2%	-12.9%	-13.6%	-15.0%	-16.2%	-16.9%	-17.4%	-17.9%	-18.5%	-19.2%	-19.9%
Oil and Gas Real GDP (2017 Dollars, $B)	-9.2	-9.8	-10.4	-11.5	-12.6	-13.3	-13.8	-14.3	-14.8	-15.5	-16.2
Real GDP	-2.7%	-2.8%	-3.0%	-3.3%	-3.6%	-3.8%	-3.9%	-4.0%	-4.1%	-4.3%	-4.5%
Real GDP (2017 Dollars, $B)	-11.2	-12.3	-13.3	-15.0	-16.6	-17.8	-18.8	-19.8	-20.9	-22.1	-23.4
Real Investments	-4.5%	-4.1%	-3.8%	-3.9%	-4.0%	-3.8%	-3.7%	-3.5%	-3.5%	-3.5%	-3.6%
Real Household Consumption	-2.5%	-2.6%	-2.7%	-3.0%	-3.2%	-3.3%	-3.4%	-3.5%	-3.7%	-3.8%	-3.9%
Real Exports	-3.8%	-4.2%	-4.6%	-5.2%	-5.7%	-6.1%	-6.4%	-6.7%	-6.9%	-7.2%	-7.5%
Real Imports	-4.5%	-4.5%	-4.6%	-4.9%	-5.2%	-5.3%	-5.3%	-5.4%	-5.5%	-5.6%	-5.8%
Employment	-1.4%	-1.5%	-1.5%	-1.6%	-1.7%	-1.8%	-1.8%	-1.9%	-1.9%	-2.0%	-2.0%
Employment (Thousands)	-41.4	-42.9	-44.6	-49.5	-53.7	-56.1	-58.1	-60.3	-62.9	-66.1	-69.5
Real Wages	-1.5%	-1.6%	-1.6%	-1.8%	-1.9%	-2.0%	-2.0%	-2.0%	-2.1%	-2.1%	-2.2%
Exchange Rate (CAD/USD)	-1.8%	-1.7%	-1.7%	-1.8%	-1.9%	-1.9%	-1.9%	-1.9%	-1.9%	-1.9%	-2.0%
Price of Imports in CAD	1.6%	1.6%	1.6%	1.7%	1.7%	1.8%	1.8%	1.8%	1.8%	1.8%	1.9%
Price of Exports in CAD	-0.1%	0.0%	0.1%	0.1%	0.2%	0.2%	0.3%	0.4%	0.4%	0.5%	0.5%
Terms of Trade	-1.7%	-1.6%	-1.5%	-1.5%	-1.6%	-1.5%	-1.4%	-1.4%	-1.4%	-1.3%	-1.3%
Government Tax Revenues	-4.3%	-4.3%	-4.4%	-4.8%	-5.0%	-5.2%	-5.2%	-5.3%	-5.4%	-5.6%	-5.8%

Figure 53: Macroeconomic Metrics: Policy vs Baseline, Per Year, Canada

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Oil and Gas Real GDP	-11.5%	-12.1%	-12.7%	-14.0%	-15.1%	-15.8%	-16.3%	-16.8%	-17.3%	-17.9%	-18.6%
Oil and Gas Real GDP (2017 Dollars, $B)	-11.1	-11.7	-12.4	-13.7	-14.9	-15.6	-16.2	-16.8	-17.4	-18.2	-18.9
Real GDP	-0.6%	-0.7%	-0.7%	-0.8%	-0.8%	-0.9%	-0.9%	-0.9%	-1.0%	-1.0%	-1.0%
Real GDP (2017 Dollars, $B)	-16.4	-18.0	-19.6	-22.2	-24.6	-26.4	-27.9	-29.3	-30.9	-32.7	-34.5
Real Investments	-1.4%	-1.2%	-1.1%	-1.1%	-1.1%	-1.1%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%
Real Household Consumption	-0.6%	-0.7%	-0.7%	-0.7%	-0.8%	-0.8%	-0.9%	-0.9%	-0.9%	-0.9%	-1.0%
Real Exports	-0.5%	-0.7%	-0.8%	-0.9%	-1.0%	-1.1%	-1.2%	-1.3%	-1.3%	-1.4%	-1.4%
Real Imports	-0.9%	-0.9%	-0.9%	-1.0%	-1.1%	-1.1%	-1.1%	-1.1%	-1.1%	-1.2%	-1.2%
Employment	-0.3%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%
Employment (Thousands)	-68.2	-70.9	-73.9	-81.9	-88.7	-92.6	-95.8	-99.2	-103.1	-107.9	-112.9
Real Wages	-0.4%	-0.4%	-0.4%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%
Exchange Rate (CAD/USD)	-1.8%	-1.7%	-1.7%	-1.8%	-1.9%	-1.9%	-1.9%	-1.9%	-1.9%	-1.9%	-2.0%
Price of Imports in CAD	1.6%	1.6%	1.6%	1.7%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.9%
Price of Exports in CAD	-0.2%	-0.2%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	0.0%
Terms of Trade	-1.8%	-1.8%	-1.7%	-1.8%	-1.9%	-1.9%	-1.9%	-1.9%	-1.9%	-1.9%	-1.9%
Government Tax Revenues	-1.0%	-1.0%	-1.0%	-1.1%	-1.1%	-1.2%	-1.2%	-1.2%	-1.2%	-1.2%	-1.3%

Appendix C – CGE Model

Deloitte's Computable General Equilibrium (CGE) model is used to estimate the economic impacts of the proposed Cap. The economic impact is estimated by comparing the Policy Scenario and the Baseline Scenario over the period.

Deloitte's CGE model is known as the Deloitte Access Economics Regional General Equilibrium Model (DAE-RGEM). It belongs to the class of dynamic multi-region computable general equilibrium models. Other models in this class include the dynamic Global Trade and Analysis model (GTAP), maintained by Purdue University, and widely used across the globe including by Global Affairs Canada and Canada's Parliamentary Budget Officer.

As many other CGE models, the core of DAE-RGEM model database is based on the GTAP database produced by Purdue University.[21] The GTAP database is a publicly available global database containing data on 160 countries (or regions).

Unlike other CGE models, DAE-RGEM also includes sub-national regions. Each Canadian individual province is treated as a separate economy in the model, allowing for the impact assessment of the proposed federal cap on the oil and gas sector emissions on provincial economies. The data on Canadian provinces in the model is based on Statistics Canada's provincial Input-Output tables.

Figure 54: Regional coverage of the GTAP database used by Deloitte's DAE-RGEM model

Source: *Global Trade Analysis Project.*

DAE-RGEM is a large scale, dynamic, multi-region, multi-commodity computable general equilibrium model. It has the following key features:

Comprehensive economic structure: The model includes all components of the economy and the interactions between them, including producers, consumers, and government, and all economic activity including production, consumption, employment, taxes, and trade.

[21] Aguiar, A., Chepeliev, M., Corong, E., & van der Mensbrugghe, D. (2023). The Global Trade Analysis Project (GTAP) Data Base: Version 11. Journal of Global Economic Analysis, 7(2); Detailed database documentation is also available at the GTAP website: GTAP 11 Database Documentation.

Inclusion of both supply chain linkages and agent behavior: The model considers how different sectors of the economy are interconnected, both in terms of supply chain linkages and based on the behavior of firms (that aim to maximize profits) and consumers (who maximize their utility).

Macroeconomic outcomes based on microeconomic foundation: The model projects changes in macroeconomic metrics such as GDP, employment, export volumes, investment, and private consumption from microeconomic decisions of consumers, firms, and technologies of firms.

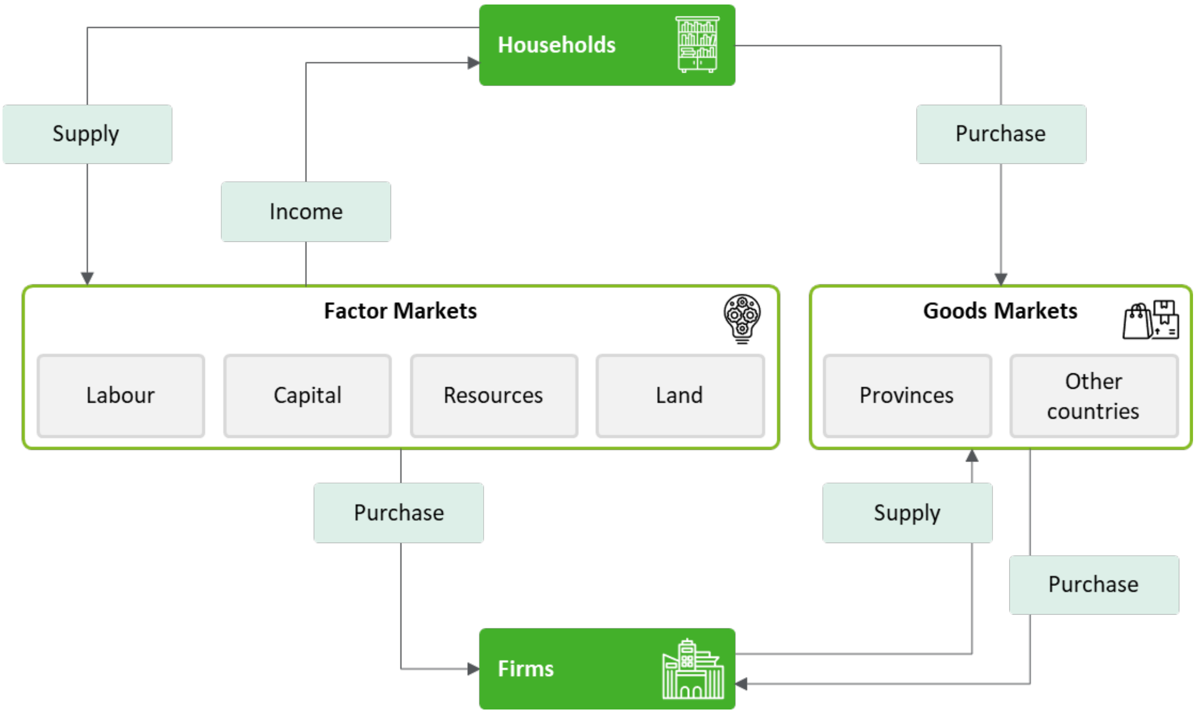
General equilibrium effects: The model includes all markets of the economy and accounts for constraints in productive capacity of the economy and scarcity of resources (labour, capital, natural resources, and land).

Dynamic projections: Impacts can be modelled both over short-term and long-term time horizons.

Geographic and industry detail: The model includes 160 regions as well as individual Canadian provinces. There are more than 30 sectors at the provincial level.

Comprehensive representation of emissions: Emissions in the model include those related to combustion of fossil-based intermediate inputs, fugitive emissions in industries, land use and animals in agriculture, and household and government consumption.

Figure 55: A visual representation of Deloitte's DAE-RGEM model



Note to Reader

The results presented within this document have been provided to the Government of Alberta for the purpose of estimating the economic impact of the proposed federal oil and gas sector emissions cap, as outlined in the Environment and Climate Change Canada (ECCC) paper: "A Regulatory Framework to Cap Oil and Gas Sector Greenhouse Gas Emissions," published in December 2023.

This study does not represent a cost-benefit analysis for the Government of Alberta or any other stakeholder and does not represent a comparison of the potential economic impact of the proposed federal oil and gas sector emissions cap with alternative policies.

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We believe that our analyses must be considered as a whole and that selecting portions of the analyses, or the factors considered by it, without considering all factors and analyses together, could create a misleading view of the issues related to the report. Amendment of any of the assumptions identified throughout this report could have a material impact on our analysis contained herein. Should any of the major assumptions not be accurate or should any of the information provided to us not be factual or correct, our analyses, as expressed in this report, could be significantly different.