FINAL REPORT

The Flip Side – What are the Economic Benefits from Carbon Capture and Storage?

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Prepared for:

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Executive Summary

While research into the costs of implementing carbon capture and storage (CCS) is extensive, these studies usually exclude any assessment of the potential economic benefits associated with CCS deployment. In this study, M.K. Jaccard and Associates (MKJA) built on earlier work by Jacobs Consultancy ("Jacobs") to conduct a complete assessment of the impact of CCS adoption on Alberta's economy.

The results showed that the ability to reduce greenhouse gas (GHG) emissions through the use of CCS could protect valuable export markets and substantially reduce the cost of complying with climate change policies. By protecting export markets, CCS could yield between $2.1 and $3.4 in additional provincial income for every dollar spent on CCS. Using CCS to help achieve GHG emission reduction targets yields between $1.4 and $2.1 of additional provincial income per dollar spent on CCS, compared to the cost of meeting these targets without CCS.

CCS could protect valuable export markets and substantially reduce the cost of complying with climate change policies. Protecting export markets could yield between $2.1 and $3.4 in additional provincial income per dollar spent on CCS, while using CCS to help achieve greenhouse gas reduction targets could yield between $1.4 and $2.1 in additional income per dollar spent on CCS.

Methodology

To conduct this analysis, MKJA used a computable general equilibrium (CGE) model of Canada and the United States called GEEM. This model shows how policies or different economic conditions alter the structure and growth of the economy, and how changes in one sector have a ripple effect throughout the economy. A number of different scenarios were evaluated, in order to assess the potential impact of CCS under different conditions:

1. No new climate change-related policies are implemented in Canada and the U.S.
2. Policies to stabilize GHG emissions by 2030 are implemented in Canada and the U.S.
3. Policies to achieve Canada's and the U.S.'s GHG reduction targets are implemented
4. The U.S. bans the construction of new pipelines from Alberta due to the high GHG emissions of crude oil from the oil sands
5. The U.S. implements a national low carbon fuel standard

Each scenario was examined under two different assumptions: CCS is available for industry to adopt and CCS is not available. The difference between the two scenarios shows the potential economic impact associated with CCS availability.

Study Highlights

1. CCS could help Alberta maintain access to U.S. export markets

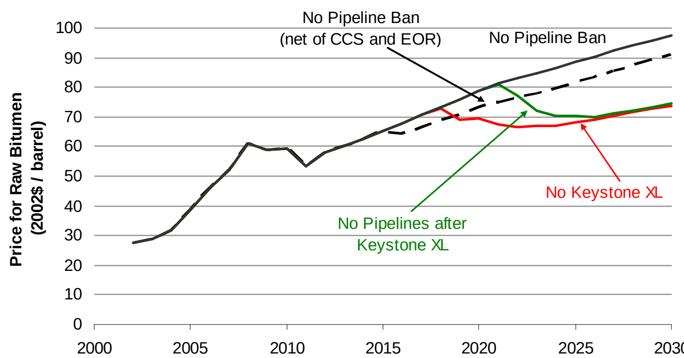
There is the potential for the United States to implement policies that restrict access of Alberta crude oil into American markets. This could be done by either imposing a ban on new pipelines carrying Alberta crude oil, or implementing a federal low-carbon fuel standard.

We explored three potential pipeline scenarios, including

1. The Keystone XL pipeline and subsequent pipelines are not built,
2. Keystone XL is built but all subsequent pipelines are not built, and
3. Alberta avoids a pipeline ban by adopting CCS.

Pipeline bans reduce the price for Alberta crude oil. Under both pipeline ban scenarios, the price on a barrel of raw bitumen is between $23 and $24 lower in 2030 (2002$) than if Alberta can avoid the pipeline ban by adopting CCS, as shown in Figure 1.

Figure 1: Price for Raw Bitumen with and without a Pipeline Ban (2002$ per barrel)



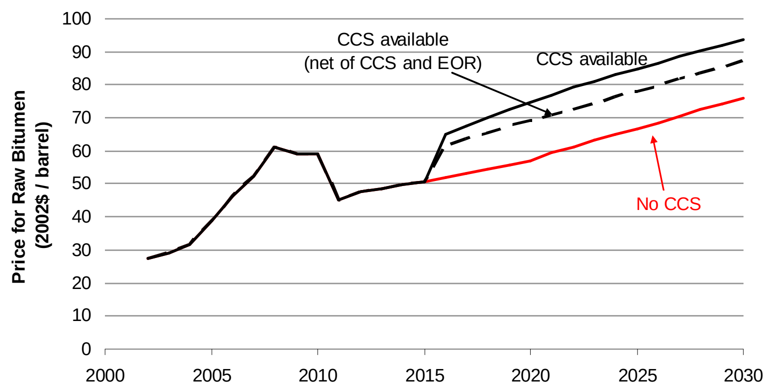
The adoption of CCS by Alberta's in-situ bitumen producers results in additional costs of $6.6 per barrel in 2030. Because the decline in crude oil prices from the pipeline bans exceeds the costs associated with adopting CCS, there is a substantial economic benefit from the adoption of CCS to avoid a pipeline ban. This yields $83 to $111 billion (2002$) in greater cumulative GDP between 2010 and 2030.

A low-carbon fuel standard also reduces the price on Alberta oil sands products. This type of policy implicitly imposes a tax on fuels with emissions intensities above the standard (such as products from the oil sands) and acts like a subsidy for fuels with intensities below the standard (such as cellulosic ethanol). However, oil sands producers can reduce their exposure to the implicit tax by reducing their GHG emissions intensity by adopting CCS.

Overall, CCS availability would add between $83 and $111 billion to Alberta's gross domestic product between 2016 and 2020, if the use of CCS ensures continued access to American crude oil markets.

The price for a barrel of raw bitumen is $18 greater in 2030 if oil sands producers adopt CCS, as shown in Figure 2, while the costs of adopting CCS for in-situ bitumen extraction are only $6.6 per barrel. Overall, the availability of CCS to Alberta's oil sands producers as an option for mitigating the impact of an American low-carbon fuel standard results in a cumulative increase in Alberta's income of $149 billion (2002$) between 2016 and 2030.

Figure 2: Price for Raw Bitumen under a United States Low-Carbon Fuel Standard



The availability of CCS to Alberta's oil sands producers as an option for mitigating the impact of an American low-carbon fuel standard results in a cumulative increase in Alberta's real gross domestic product of $149 billion by 2030.

2. CCS can reduce the costs to industry of complying with climate change policies

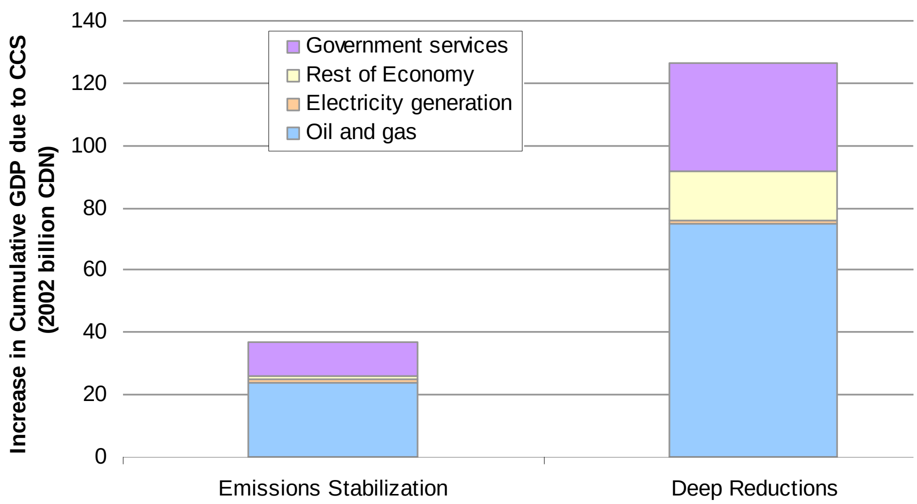
The benefit that CCS has on Alberta's value-added industries depends on the aggressiveness of the GHG emission reduction policies that are in place. Under current policies, CCS provides a niche benefit by enabling the development of enhanced oil recovery. This allows for more aggressive growth in the conventional oil and government sectors, with the latter benefiting from higher royalties. Under current policies, cumulative real domestic product is $17 billion greater when CCS is available.

As policies to reduce GHG emissions become more aggressive, industry can reduce the impact of the policies by adopting CCS. For example, if a policy imposes a cost of $150 per tonne CO_2e and the cost of adopting CCS is $100 per tonne, CCS would provide a benefit to industry. The oil and gas and government sectors are the most significant beneficiaries from CCS availability. If Canada stabilizes its emissions by 2030, the availability of CCS adds $37 billion to provincial income between 2016 and 2030. If Canada achieves its targets for greenhouse gas emissions – a 17% reduction from 2005 levels by 2020 and a 65% reduction by 2050 – CCS availability adds $126 billion to provincial income.

Figure 4 shows the cumulative increase in Alberta's gross domestic product from 2010 to 2030 due to CCS availability.

CCS availability would reduce the costs of complying with a policy to stabilize Canada's emissions by 2030 or to achieve Canada's targets for emissions in 2020 and 2030. Lower costs of compliance from CCS availability could lead to an increase in Alberta's cumulative GDP of $37 billion (emissions stabilization) to $126 billion (achieving Canada's targets for emissions).

Figure 4: Economic Benefits Associated with Lower Costs to Industry of Complying with Climate Change Policies



3. **Enhanced oil recovery would reduce the costs for CCS in the short- to medium-term and increase conventional oil production in the long-term**

Enhanced oil recovery (EOR) provides two main benefits to Alberta's economy:

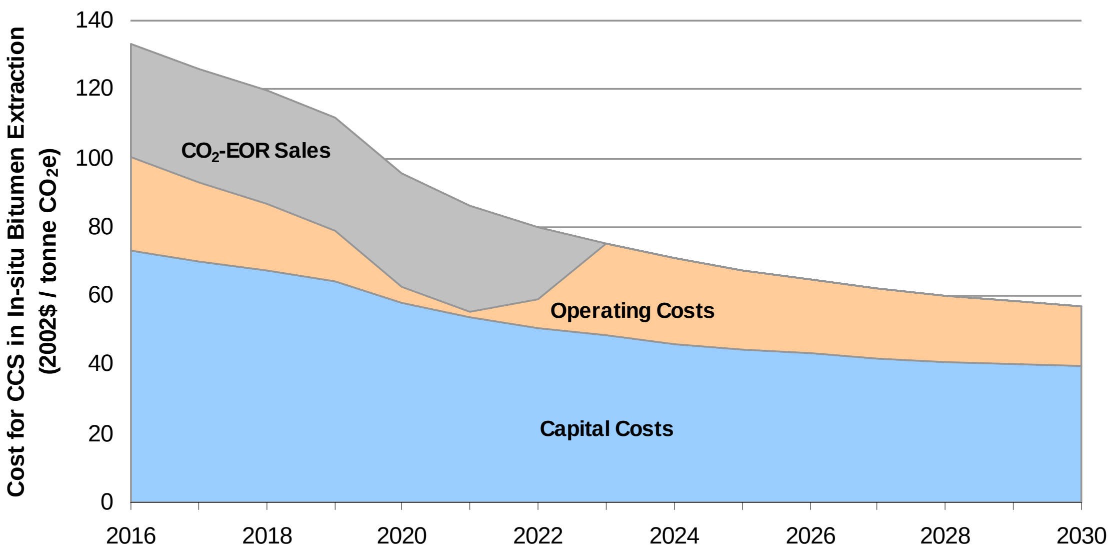
1. Carbon dioxide sales benefit facilities that adopt CCS by offsetting a portion of the costs from installing and operating CCS equipment.
2. Greater conventional oil production leads to economic growth and higher government royalties

CO_2 sales for enhanced oil recovery act as a bridge from when CCS costs are highest in the near-term to when costs are lower in the medium-term.

Under policies leading to rapid deployment of CCS, CO_2 sales for enhanced oil recovery act as a bridge to lower CCS costs. While the price for carbon dioxide will decline to zero when its supply exceeds demand, by this time the costs of CCS will have started to fall due to experience with the technology.

Figure 5 shows the cost for CCS at an in-situ bitumen facility with CO_2 sales for EOR (results are shown for the scenario where Canada achieves its greenhouse gas emission reduction targets). The top of the stack of wedges indicates the cost of CCS if EOR were not available, while the grey wedge indicates the economic benefit to the facility from CO_2 sales. The total cost for CCS without CO_2-EOR sales would begin at $133 per tonne CO_2e in 2016, but EOR sales reduce the costs by $33 per tonne to $100 per tonne. By 2023, supplying CO_2 for EOR no longer provides a benefit to the CCS plant, but over this period the costs associated with adopting CCS have declined by 44% due to experience, bringing the total costs down to $75 per tonne CO_2e.

Figure 5: Benefit to CCS plant from CO_2 sales for EOR (2002$ / tonne CO_2e)



The second benefit from EOR is related to greater conventional oil production. This increases economic activity in the oil and gas sector and maintains stronger oil and gas royalties to government than in the absence of EOR. Between 2016 and 2030, cumulative royalties due to EOR are estimated at between $7 and $15 billion (2002$).

4. CCS will enable the continued use of coal to generate inexpensive electricity

Under policies to reduce GHG emissions, electricity generators have three main abatement options:

1. Adopt CCS at coal and natural gas fuelled power plants;
2. Switch from high GHG emissions intensity fuels such as coal to lower intensity fuels such as renewable resources or natural gas; and
3. Increase electricity imports from regions with lower GHG emissions intensity, such as importing hydroelectricity from British Columbia.

The availability of CCS leads to electricity prices that are $10 to $50 per MWh lower in 2030, depending on the GHG reduction policies in place.

CCS availability would reduce the emissions intensity of coal-fuelled electricity generation and help maintain lower electricity prices. Under policy scenarios that either achieve emissions stabilization or achieve Canada's GHG emission reduction targets, the availability of CCS leads to electricity prices that are $10 and $50 per MWh (2002$) lower in 2030 respectively.

5. **CCS could help to avert social pressures related to Alberta's oil sands**

By taking a leading role in the development and deployment of CCS, Alberta is showing world leaders and citizens that the province takes climate change seriously.

Over the past several years, Alberta has been the target of a series of increasingly active and well-funded campaigns aimed at slowing or halting oil sands development. It is difficult to estimate the economic results of these campaigns. While the impact of any one campaign may be insignificant economically, the cumulative effect on Alberta's international reputation could be much greater, with implications for international relations, attraction of business and investment, tourism, access to labour, and federal/provincial relations. By taking a leading role in the development and deployment of CCS, Alberta is showing world leaders and citizens that the province takes climate change seriously and is actively investing in solutions, which may help the province to counter and dilute the message that the public is receiving from anti-oil sands campaigners.

6. **CCS could increase the size and economic impact of Alberta's knowledge sector**

The development of knowledge that reduces the cost of CCS deployment and the training of skilled researchers and workers for the CCS industry are likely to have a significant positive impact on Alberta's economy.

Alberta's investments in and commitment to CCS position the province as an applied science and innovation leader, which may help to attract researchers to Alberta and spur the development of new knowledge institutions. The economic effects of this knowledge sector growth could include revenue and economic spin-offs resulting from the attraction of foreign students and researchers to Alberta, the development of marketable technologies and intellectual capital by these researchers, the development of knowledge that will contribute to lowering the costs of CCS deployment in Alberta, and the training of skilled researchers and workers who may help to ameliorate potential future skilled worker shortages in the CCS field. The latter two benefits in particular are likely to have a significant positive impact on Alberta's economy.

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Introduction

Carbon capture and storage (CCS) has emerged as a promising technology for Alberta to achieve deep reductions in greenhouse gas emissions. To achieve Alberta's target for greenhouse gas emissions in 2050, Alberta's Climate Change Strategy estimated that 140 tonnes of carbon dioxide equivalent (CO_2e) - about 70% of emission reductions - would come from CCS.[1] However, achieving widespread adoption of the technology faces several challenges. Commercial experience with CCS is limited, with only a few sites globally using the technology. Of these sites, most are natural gas processing plants, and there is no commercial-scale experience with capturing combustion emissions.[2] An additional challenge is the cost imposed on industry from the adoption of the technology. A plant equipped with CCS has greater capital, energy and operating requirements than an equivalent plant without CCS. Therefore the adoption of CCS could render industrial facilities in Alberta less competitive with other jurisdictions.

Despite these challenges, the adoption of CCS could also benefit Alberta's economy. Alberta Innovates – Energy and Environment Solutions, Alberta Energy and Alberta Environment (henceforth called the "steering committee") have identified several potential benefits:

- The adoption of CCS may help maintain access to export markets for commodities produced in Alberta. CCS may prevent regulations in the United States that restrict imports from Alberta (e.g., a ban on new oil pipelines into the United States). It may also be an economical way of complying with an American low-carbon fuel standard. The use of CCS may also avert increases in the cost of capital stemming from shareholder activism and other challenges to the oil sands industry's social license to operate;
- The adoption of CCS may have a positive impact on Alberta's economic activity, especially under policies to reduce greenhouse gas emissions;
- The carbon dioxide (CO_2) captured from facilities with CCS could be used for value added activities such as enhanced oil recovery;
- If firms in Alberta adopt CCS before firms in other jurisdictions, Alberta could develop expertise in designing, constructing and maintaining CCS facilities, and may be able to export that expertise to other jurisdictions that adopt the technology;
- Early adoption of CCS could attract researchers, academics and other skilled workers to Alberta.

[1] Alberta Environment, 2008, *Alberta's 2008 climate change strategy*, available from: environment.alberta.ca.
[2] Global CCS Institute, 2011, *The global status of CCS: 2010*, available from: www.globalccsinstitute.com.

- The use of carbon capture and storage in a carbon constrained world could allow Alberta to continue to use its coal resources.

The steering committee retained M.K. Jaccard and Associates Inc ("MKJA") and Jacobs Consultancy ("Jacobs") to assess the benefits to Alberta's economy from CCS adoption. This report presents the results of MKJA's economic modelling and analysis.

This report is organized as follows: The first section describes the methodology used to analyze the benefits from CCS. This is followed by a presentation of the results from the reference case projection, the policy scenarios, and the sensitivity analyses. The next section discusses other potential benefits of CCS, including counteracting social challenges to the oil sands industry and growth in the knowledge sector. Finally, the concluding section summarizes the key findings from the analysis and suggests possible extensions to this work that the steering committee may wish to investigate in the future.

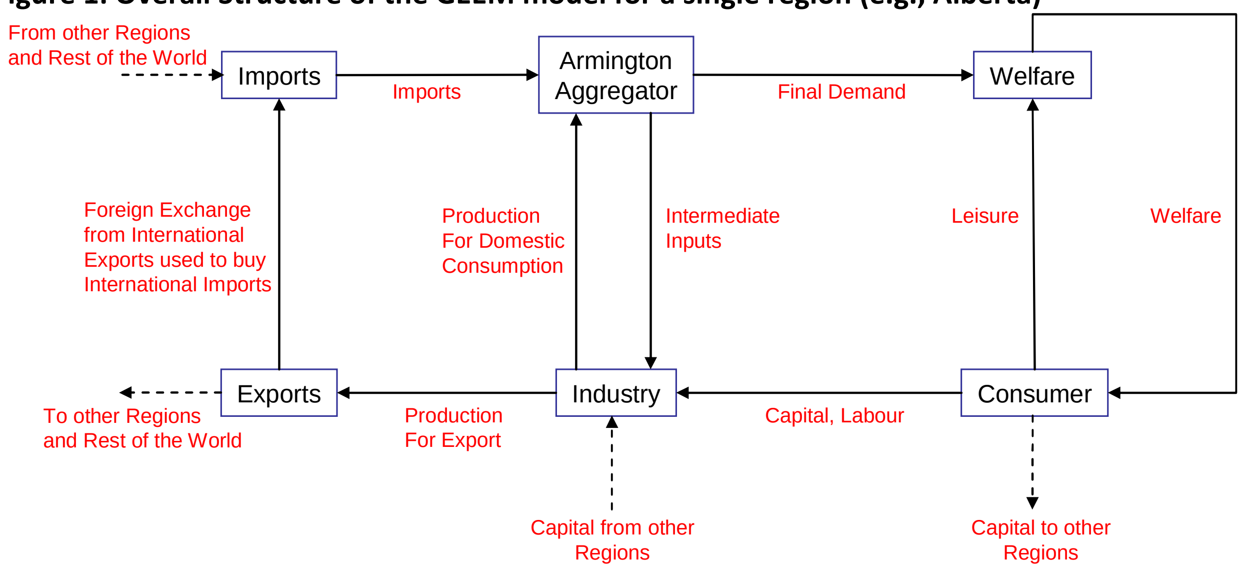
Methodology

Modelling Framework

To complete the analysis, MKJA employed a computable general equilibrium model called GEEM. This section introduces how the model operates and how it determines the impact of CCS on Alberta's economy. Full documentation of the model's structure and methodology are provided in Appendix 1: The GEEM Model.

Computable general equilibrium (CGE) models simulate how commodities and factors of production (i.e., capital and labour) are allocated throughout the economy. Each industrial sector is characterized by what it produces (e.g., crude bitumen) and the inputs required in production (i.e., capital, labour, energy and materials). Households are the final consumers of goods produced in the economy and are characterized by the commodities they consume. Households are further endowed with primary factors of production (labour, capital and land/resources) which they lend to industry in return for personal and corporate income. As the model steps through time, it ensures the demand for all commodities and factors matches supply by adjusting prices. For example, growth in oil sands production requires additional cement inputs which must be produced by the cement manufacturing sector or imported. The price for cement increases or decreases until its market arrives at equilibrium. The key economic flows in GEEM are captured schematically in Figure 1.

Figure 1: Overall Structure of the GEEM model for a single region (e.g., Alberta)



Due to their framework, CGE models show how policies or different economic conditions alter the structure and growth of the economy. A policy leading to the contraction of one sector has a ripple effect throughout the economy as all sectors of the economy return to equilibrium. For a simple example, a policy causing an increase in the cost of crude bitumen production would reduce the supply of bitumen (assuming the price for bitumen is held constant). In turn, lower bitumen production would reduce the output from sectors that supply the bitumen industry with goods and services, and capital and labour would be reallocated throughout the economy. The impact of this simple example on Alberta's economic structure and growth is determined by 1) where capital and labour are re-allocated to, and 2) whether the new allocation of capital and labour generates the same or different incomes in the region. Greater incomes imply greater economic growth.

To simulate how CCS deployment affects Alberta, the GEEM model has been customized to capture key characteristics of Alberta's economy and how Alberta interacts with the rest of the world:

- The version of GEEM used in this analysis has been disaggregated into three regions: 1) Alberta, 2) the remaining Canadian provinces and 3) the United States. Regional disaggregation allows for the representation of two dynamics:
  - The trade of commodities and services: Alberta exports a large portion of its industrial production (specifically oil and natural gas). As a result, industrial production is contingent on policies and economic conditions in other jurisdictions in addition to policies and conditions in Alberta. Policies implemented in Alberta could also affect the competitiveness of domestic production in international and interprovincial markets.
  - The competition for capital between regions: Capital is assumed to be perfectly mobile among regions, meaning that the rate of return to capital is equalized across all sectors in North America. The assumption about capital has implications for economic growth in Alberta as policies and economic conditions alter the allocation of capital between regions. A greater allocation of capital typically stimulates economic growth.
- The model has been designed to provide a high degree of disaggregation of the most energy and emissions intensive sectors of the economy. The oil and gas sector has been disaggregated into 1) mined bitumen extraction, 2) in-situ bitumen extraction, 3) bitumen upgrading, 4) conventional light/medium oil production, 5) conventional heavy oil production, 6) conventional natural gas production, 7) unconventional natural gas production with high concentrations of formation CO_2 and 8) unconventional natural gas production with low concentrations of formation CO_2. Each of the oil sectors produces oil commodities of different qualities. Synthetic and light/medium oil have the highest quality (or require the fewest inputs in refining), while crude bitumen has the lowest quality. The energy and emissions required to upgrade heavy oil are captured in the downstream refining sector, while the energy and emissions required for bitumen upgrading are captured in the upstream oil and gas sector.

Manufacturing sectors are further disaggregated into the most greenhouse gas intensive sectors, including cement, lime, iron and steel, petroleum refining, etc.

- The model explicitly represents CCS in several sectors of the economy, as described below in the Assumptions section of the report.

Assumptions

The GEEM model has been updated with the costs for CCS estimated by Jacobs. Jacobs provided cost ranges for five applications of CCS. The base values used for the initial analysis are the low end of each technology's range plus 20%. This parameterization was developed in consultation with the steering committee and Jacobs. The implications of the full range of costs are explored in the sensitivity analyses. Table 1 summarizes the range of costs provided by Jacobs, the cost figures used in this analysis. Note that all values have been converted to 2002 Canadian dollars and to 2002 energy prices, since this is the year in which the model begins simulating. As the model progresses through time and prices for energy change, the costs of each CCS technology change accordingly.

Table 1: Cost of carbon capture and storage (2002$ CDN per tonne CO_2e avoided)

	Cost of CCS (2002 $ CDN / tonne CO_2e avoided)		
	Jacobs - Low	*Jacobs - High*	*Base value for analysis*
Tranche 1: Steam methane reforming (hydrogen production) in upgrader	$69	$108	$83
Tranche 2: In-situ bitumen extraction	$92	$163	$111
Tranche 3: Coal-fired electric generation	$71	$110	$85
Tranche 4: Natural gas-fired electric generation	$85	$131	$102
Tranche 5: Small process heaters	$170	$412	$204

In addition to CCS technologies which were directly informed by Jacobs' analysis, the results are sensitive to other applications of CCS throughout the economy. Furthermore, Alberta's energy and economic profiles are dependent on CCS technologies available in other jurisdictions. For example, CCS adoption in electricity generation in the United States could affect natural gas prices, and therefore exports from Alberta. MKJA used the information provided by Jacobs to inform assumptions about CCS technologies in several other sectors and regions of the economy. Table 2 illustrates the characterization of these technologies and describes how information from Jacobs informs this characterization.

Several sectors of the economy have multiple applications of CCS, each with different costs. In the analysis CCS deployment occurs in steps, with the least costly applications adopted at less aggressive policies and the more costly applications adopted as policies become more aggressive. As CCS deployment becomes more aggressive, the greenhouse gas intensity of the industry declines. For example, bitumen upgrading has three applications of CCS technologies. CCS is first deployed to capture the emissions from hydrogen production, and reduces the emissions intensity of bitumen upgrading from 53 kg CO_2e per barrel of synthetic crude to 37 kg CO_2e. If policies become more aggressive, the sector can achieve further abatement by adopting CCS for large and small process heaters, which reduce the greenhouse gas intensity of the sector to 22 and 8 kg CO_2e per barrel of synthetic crude respectively.

Applications of CCS covering the combustion emissions from bitumen upgrading and bitumen mining are divided into large and small process heaters. The large process heaters are assumed to have the same cost as in-situ bitumen extraction (i.e., Tranche 2 in Table 1), while the small process heaters are assumed to have the same cost as small process heaters (Tranche 5 in Table 1). Emissions produced by large process heaters are assumed to represent one half of total combustion emissions in both bitumen mining and upgrading. This ratio is based on discussions with the steering committee and Jacobs.

The costs shown in Table 1 and Table 2 are based on prices for energy in 2002. In the analysis, these prices change over time leading to higher or lower costs for CCS. For example, the price for natural gas is assumed to be $3.88 per mmBTU in Table 1 and Table 2, but as the price for natural gas increases over time the cost of applications of CCS that consume natural gas increase as well.

Table 2: Additional CCS technologies in GEEM

	Base Cost used by MKJA (2002 $ CDN / tonne CO_2e avoided)	***GHG Intensity of Industry***		***Notes***
		kg CO_2e/Unit	***Units***	
Bitumen upgrading				
Without CCS		53	kg CO_2e per barrel of synthetic crude oil	Baseline technology
Step 1: Hydrogen production	$83	37		Cost is based on estimate for a SMR plant
Step 2: Large process heaters	$111	22		Based on estimate for in-situ bitumen extraction
Step 3: Small process heaters	$204	8		Cost is based on estimate for small process heaters
Mined bitumen extraction				
Without CCS		41	kg CO_2e per barrel of bitumen	Baseline technology
Step 1: Large process heaters	$111	27		Based on estimate for in-situ bitumen extraction
Step 2: Small process heaters	$204	20		Cost is based on estimate for small process heaters

	Base Cost used by MKJA (2002 $ CDN / tonne CO_2e avoided)	GHG Intensity of Industry		Notes
		kg CO_2e/Unit	Units	
Natural Gas Production				
Without CCS		6.3	kg CO_2e per thousand cubic foot (Mcf)	Baseline technology
Step 1: Capture of formation carbon dioxide	$83	4.5		Cost is based on estimate for a SMR plant
Step 2: Capture of combustion emissions	$111	1.6		Based on estimate for in-situ bitumen extraction
Petroleum Refining (Light/medium and synthetic oil)				
Without CCS		202	kg CO_2e per m^3 Refined Petroleum Products	Baseline technology
Step 1: Large process heaters	$111	154		Based on estimate for in-situ bitumen extraction
Step 2: Small process heaters	$204	28		Cost is based on estimate for small process heaters
Petroleum Refining (Heavy oil)				
Without CCS		302	kg CO_2e per m^3 Refined Petroleum Products	Baseline technology
Step 1: Hydrogen production	$83	280		Cost is based on estimate for a SMR plant
Step 2: Large process heaters	$111	230		Based on estimate for in-situ bitumen extraction
Step 3: Small process heaters	$204	42		Cost is based on estimate for small process heaters
Cement, Lime and Iron and Steel Manufacturing				
Without CCS		100	Index - without CCS = 100	
Step 1: Small process heaters	$204	13		Cost is based on estimate for small process heaters

Most analysts believe that the cost of CCS will decline with accumulated experience. Based on MKJA's review of the literature on technology learning rates (summarized in Appendix 2), learning rates of 11% (for capital costs) and 22% (for operating costs) were used for our analysis. The learning rate is the percentage decline in costs resulting from every doubling of production. The operating costs that were subject to technology learning were additional energy costs from operating CCS equipment.[3] Since CCS cost declines are a function of accumulated experience in all jurisdictions, the maximum decline in CCS costs would be achieved if CCS becomes widely adopted across North America. Likewise if CCS adoption is limited to Alberta, the cost declines are less prominent. For this analysis, the model was parameterized so that a 50% decline in

[3] An industrial facility equipped with CCS requires more energy than an equivalent facility without CCS. This energy penalty from CCS declines in the modelling as a result of accumulated experience with CCS. Energy penalties in the analysis are based on the Intergovernmental Panel on Climate Change's Special Report on Carbon Dioxide Capture and Storage (2005).

capital costs is observed under a policy scenario that results in aggressive adoption of CCS throughout North America by 2030. In the sensitivity analyses, the impact of a more aggressive decline in CCS costs (50% by 2020) is explored, to account for the possibility that technological breakthroughs will substantially reduce the costs of CCS in the current decade.

The capital and operating cost decline function in GEEM is defined as:

$$DC = MAX\left[\left(1-\left(\frac{CCSI_t}{CCSI_0}\right)^{\frac{LN(PR)}{LN(2)}}\right), MAXDEC\right]$$

Where,

> DC is the percent decline in capital or operating costs from the base year value (as displayed in Table 1 and Table 2).
>
> $CCSI_t$ is the cumulative investment in CCS in each time period. The cumulative investment in CCS (or related technologies such as amine separation in natural gas production) is assumed to be \$2.5 billion in 2002 ($CCSI_0$).
>
> PR is one minus the percent decline in costs that results from every doubling of production. The percent decline in capital costs for a doubling of production is 11% so the PR is 0.89. The PR for operating costs is 0.78.
>
> MAXDEC is the maximum decline in capital costs allowed in the analysis. The maximum decline in capital and operating costs are 46% and 74% respectively. This allows the total costs for CCS to decline by approximately 60%.

The analysis also explores the effect of enhanced oil recovery (EOR) on Alberta's economy. In GEEM all facilities that install carbon capture technology can transport the CO_2 to either an EOR site or a non-EOR storage site. The costs of transporting CO_2 from the point of capture to a non-EOR storage site are captured in the costs supplied by Jacobs (see Table 1 and Table 2). In Alberta, the costs of transporting CO_2 to an EOR site and to a storage site are assumed to be the similar, as they are located in approximately the same areas.[4] We assume that the incremental cost of transporting CO_2 to an EOR site to be \$2.5 per tonne CO_2.

EOR becomes economically viable once the revenue earned from selling the incremental oil produced from EOR exceeds the costs associated with purchasing the CO_2 and building and operating the EOR site. Jacobs has informed these parameters, as shown in Table 3. The costs in Table 3 exclude the costs of associated CO_2 purchases, but show the quantity of CO_2 required to produce an incremental barrel of oil. The costs associated with CO_2 purchased are based on the price for CO_2, which is endogenously determined by GEEM. Additionally, oil producers are assumed to require a 35% rate of

[4] Communication with ICO_2N

return on investment for EOR to be economically viable. These EOR costs are based on consultation with the steering committee.

Table 3: Characterization of EOR technology in GEEM

	Cost of EOR (2002 $CDN / incremental barrel)	*Net CO_2 usage (t CO_2 / incremental barrel)*
Jacobs - Low	$30	0.17
Jacobs - High	$55	0.32
Used by MKJA	$55	0.30

Timeframe

The analysis occurs from 2002 to 2030. MKJA selected a medium timeframe because a short-term analysis (to 2020) may not be sufficient to show significant adoption of CCS, whereas uncertainties become increasingly more pronounced in a long-term analysis (to 2050).

The analysis begins from 2002 for several reasons. First, beginning the modelling from a historic period provides an opportunity to backcast – run the model through historic data to see how it performs. Starting in 2002 also enables the model to show how oil production expanded considerably after 2002 in response to higher oil prices.

Scenarios Explored in the Analysis

This report analyzes the macroeconomic effect of several climate policy scenarios under two different assumptions about the availability of CCS. Each climate policy scenario is examined when CCS is available to industry and when CCS is not available. The difference between the two scenarios indicates the benefit (or cost) associated with CCS availability.

Policy Scenarios

Current Policies

The first policy scenario represents the North American economy under current policies. The policies included in this scenario are:

- Alberta's Specified Gas Emitters Regulation. Beginning in 2007, large final emitters in Alberta were required to reduce their combustion greenhouse gas intensities by 12% from their average intensities between 2003 and 2005. New facilities (i.e., those built after 2000) face a three year grace period, after which they must reduce their intensities by 2% annually until they achieve a 12% reduction. Permits between firms are tradable, so firms that exceed their intensity target can sell permits to firms that exceed their target. To comply with the regulation, firms can also purchase offsets from sectors not covered by the regulation or credits from the Climate Change and Emissions Management Fund (a technology fund), which can be accessed at $15 per tonne CO_2e (current dollars). Funds from the technology fund are re-invested in low- and zero-emissions technologies throughout Alberta's economy.[5]

The specification of this policy in GEEM has been modified to ease its representation in the model. After 2007, industrial sectors must reduce their combustion emissions intensities by 12% below 2002 levels. Compliance mechanisms include purchasing credits from other firms or contributing to the technology fund, which can be accessed at $15 per tonne CO_2e in current dollars (i.e., declining real dollars over time, due to inflation). Contributions to the technology fund are invested in renewable electricity generation, although subsequent analyses could extend the reinvestment of the fund to other low- and zero-emissions technologies (e.g., CCS).

- An emissions standard for passenger vehicles in Canada and the United States. The emissions standard begins in 2012 and calls for a reduction in the average emissions intensity of new passenger vehicles in Canada and the United States. The policy has been synchronized between Canada and the United States, and calls for the emissions intensity of passenger vehicles to be approximately 155 kg CO_2e per vkt by 2016. This represents about a 34% reduction in the emissions intensity of vehicles compared to the current fleet in Canada.[6]
- Renewable portfolio standards (RPS) for the United States and Canada. Several American states have established minimum requirements for electricity generation from renewable resources. Likewise some Canadian provinces have implemented policies that limit fossil fuel generation. For example, British Columbia has mandated that 93% of electricity generation be from renewable resources, while the government of Ontario has mandated a closure of all coal plants by 2015. The renewable portfolio standards in the analysis requires that Alberta, the rest of Canada and the United States achieve an 11%, 74% and 13% generation from renewable resources by 2030, respectively.

Some policies implemented throughout North America have been excluded from the current policy projection, including:

- California's Low Carbon Fuel Standard. Although this policy is likely to have a significant impact on energy and greenhouse gas emissions from transportation fuel consumption in California, it is less likely to affect Alberta. At present, Alberta exports a small amount of oil to California and any constraint imposed by

[5] Alberta Environment, 2007, *Technical guidance document for baseline emissions intensity applications*, available from www.environment.gov.ab.ca.
[6] Environment Canada, 2010, "Canada announces final GHG emission regulations for new light-duty vehicles", available from www.ec.gc.ca; Natural Resources Canada, 2011, *Comprehensive energy use database*, available from www.nrcan-rncan.gc.ca; US Environmental Protection Agency, "EPA and NHTSA finalize historic national program to reduce greenhouse gases and improve fuel economy from cars and trucks", available from www.epa.gov.

California could be addressed by reorganizing exports (e.g., exporting a greater portion of oil to unregulated jurisdictions in North America). However, an extension of this policy to the federal level in the United States is analyzed in a separate policy scenario.

- Other policies implemented at a state or provincial level have not been included in the analysis. For example, British Columbia's carbon tax, Quebec's carbon levy and the potential cap-and-trade system under the Western Climate Initiative are excluded. These policies are excluded for simplicity, but could affect North American demand for fossil energy.

Emissions Stabilization and Deep Reductions Policies

Canada has committed to reducing greenhouse gas emissions to 17% below 2005 levels by 2020 and 65% below 2005 levels by 2050.[7] The United States has committed to reducing emissions by 17% from 2005 levels by 2020 and 83% by 2050.[8] We explore the impact of achieving these targets on Alberta's economy in a "Deep Reductions" scenario. Despite these aggressive targets for greenhouse gas emissions, there is a possibility that governments in Canada and the United States will not enact policies to achieve these targets, and will instead pursue more moderate policies to reduce emissions. We analyze the impact of this approach in an "Emissions Stabilization" scenario. In this scenario, governments implement policies sufficient to stabilize greenhouse gas emissions at 2005 levels by the year 2030. The targets for emissions in these scenarios are shown in Table 4. The negative numbers indicate that emissions are permitted to increase from 2005 levels, although the increase from 2005 levels still represents a decline from the emissions projected under the current policies scenario.

The Emissions Stabilization and Deep Reductions scenarios include all current policies as well as economy-wide carbon pricing in Canada and the United States. The targets for greenhouse gas emissions are set for each scenario, and the model then determines the emissions price that achieves the target. As the model simulates every year between 2002 and 2030, interim targets for emissions are extrapolated from targets set for 2020 and 2050, as shown in Table 4. For simplicity, we assume the same target for both Canada and the United States.

Table 4: Targets for greenhouse gas emissions under the emissions stabilization and deep reduction scenarios (% reduction from 2005 emissions)

	2015	*2020*	*2025*	*2030*
Emissions Stabilization	-8%	-10%	-5%	0%
Deep Reductions	9%	17%	25%	33%

[7] Environment Canada, 2010, "Canada lists emissions target under Copenhagen Accord", available from www.ec.gc.ca.
[8] U.S. Department of Energy, 2009, "President Obama sets a target for cutting U.S. greenhouse gas emissions", available from apps1.eere.energy.gov.

Table 5 presents the greenhouse gas emission and oil prices that were used for each scenario. The prices for light oil are from the International Energy Agency, and supplied to MKJA by Jacobs.

Table 5: Price for oil and greenhouse gas emissions

	2010	*2015*	*2020*	*2025*	*2030*
Price for light oil (2002 $CDN / barrel)					
Current Policies	$77	$84	$98	$109	$118
Emissions Stabilization	$77	$81	$91	$98	$104
Deep Reductions	$77	$80	$84	$87	$87
Price for Technology Fund credits under the Specified Gas Emitters Regulation (2002 $CDN / tonne CO_2e)					
Current Policies	$13	$12	$11	$10	$9
Emissions Stabilization	$13	Determined endogenously by the model			
Deep Reductions	$13				

Policies and actions to access to export markets and the market for capital

In addition to policies to reduce greenhouse gas emissions, Alberta's trading partners may enact policies to limit the import of carbon intensive goods from Alberta, and stakeholders may take actions that increase costs for oil sands producers. We examine three options for such policies and actions:

1. **Policies to limit exports of Alberta's oil sands (oil pipeline ban)**
   Alberta's trading partners may choose to limit the amount of oil imported from Alberta's oil sands. Alberta currently exports a significant volume of oil and refined petroleum products to the United States and the United States is expected to be the main market for growth in the oil sands. To access this market, Alberta requires a network of pipelines to major refineries in the U.S. Midwest, Gulf region or other regions. Alberta currently has pipeline capacity with a total of about 3,200 thousand barrels per day, but the projected growth for oil sands production would require new pipelines after 2017. The Keystone XL pipeline to the Gulf region would add an additional 700 thousand barrels per day of capacity, resulting in a total capacity of 3,900 thousand barrels per day. However this pipeline has not yet been approved by the U.S. State Department, and is currently undergoing a protracted environmental review. The U.S. Environmental Protection Agency, numerous members of the U.S. Congress and the U.S. environmental community have objected to the pipeline on the basis that the high carbon intensity of crude oil produced from oil sands will undermine the United States' climate and clean energy objectives.[9] The U.S. State Department is currently preparing its final environmental report on the

[9] United States Environmental Protection Agency, June 6, 2011, Letter reviewing the Supplemental Draft Environmental Impact Statement for the Keystone XL pipeline, sent to the U.S. Department of State; Vanderklippe, Nathan and Shawn McCarthy, June 13, 2011, "Without Keystone XL, oil sands face choke point", *The Globe and Mail*. http://m.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/without-keystone-xl-oil-sands-face-choke-point/article2052562/?service=mobile

project, and will make a decision on whether or not Keystone XL can proceed by November 1, 2011. If Keystone XL is not built, Alberta could face pipeline constraints by 2017; if it is built but Congress implements a moratorium on future pipelines, Alberta could face constraints around 2022.[10]

One potential benefit associated with the deployment of CCS in Alberta is that by lowering the carbon intensity of crude oil from the oil sands, CCS could avert a United States pipeline ban. While greenhouse gas emissions are not the only concern about the Keystone XL pipeline, and so the assumption that the adoption of CCS could avert a pipeline ban oversimplifies the issue, modelling the scenarios in this way allows us in to understand the scale a pipeline ban's potential impact, and CCS's potential role. We examine two scenarios in this analysis:

1. The Keystone XL pipeline is not built, and
2. Pipelines subsequent to the Keystone XL pipelines are not built.

As this policy limit's Alberta's access to crude oil markets, the price Alberta receives for its crude oil diverges from other benchmark prices (e.g., West Texas Intermediate at Cushing Oklahoma). Our analysis estimates this decline in price under the pipeline ban scenarios and compares the decline to the cost of adopting CCS.

Under both pipeline ban scenarios, Alberta cannot access international markets through new pipelines to the west coast of British Columbia (e.g., Enbridge's Northern Gateway project). The purpose of this scenario is to explore the implication of losing access to export markets due to the relatively high emissions intensity of producing oil from the oil sands. Therefore, this scenario deliberately excludes the possibility of exporting crude oil to markets in Asia or elsewhere through additional capacity to the west coast.

2. **United States Low Carbon Fuel Standard**
   MKJA explored a scenario where the United States implements a low-carbon fuel standard (LCFS) on transportation fuels. A LCFS encourages substitution from high carbon intensity fuels to low intensity fuels by requiring the average carbon intensity of fuels to decline over time. The LCFS proposed for California includes both the upstream emissions from fuels manufacturing and the downstream emissions, so the upstream oil industry can reduce exposure to an LCFS by reducing its greenhouse gas intensity through the adoption of carbon capture and storage or other forms of abatement.

The LCFS examined in this analysis is based on California's policy, which calls for a 10% reduction in the average upstream and downstream greenhouse gas intensity of transportation fuels from 2011 levels by 2020. We show the effect

[10] Canadian Association of Petroleum Producers, 2010, *Crude oil forecast, markets and pipelines*.

of this policy if it were implemented at a federal level in the United States. As discussed above, Alberta is not likely to be significantly impacted if the LCFS is limited to California, as Alberta does not export significant volumes of oil to that state. The small volumes of Alberta crude oil shipped to California could be diverted to other markets if the policy is isolated to that jurisdiction.

A LCFS acts like an implicit tax (or "shadow price") on high carbon intensity fuels and a subsidy on low intensity fuels. Relatively few studies have been conducted to estimate the economic effects or the shadow price imposed by the policy. However Holland *et al* estimate the shadow price to be between \$308 and \$2,300 per tonne CO_2e (2009 \$ US). The lower range shows results with more optimistic assumptions about cellulosic ethanol while the higher range shows less flexibility for substitution between low and high carbon intensity fuels.[11] In our analysis we examine the lower range of this estimate as it is sufficient to show a benefit from carbon capture and storage under a United States LCFS. However, the costs imposed on Alberta from this policy (and the associated benefit from CCS) would be greater under a higher implicit tax.

3. **Shareholder Activism and Social License to Operate**

MKJA also explored several scenarios under which shareholder activism increases the cost of capital. At least five companies with major investments in the oil sands have been targets of shareholder activism over the past few years, with activist investors pressuring them to fully disclose and justify their involvement in the oil sands. There are concerns that shareholder activism could increase the cost of capital or lead to short-term capital shortages for oil sands projects, and the research in this area is further discussed in the Other Benefits of CCS section later in this report.

In order to evaluate the impact that an increase in the cost of capital could have on oil sands investments, and whether or not the use of CCS is a viable option to avoid these costs, MKJA ran several scenarios where global investors impose an implicit tax on capital allocated to Alberta's oil sands industries (i.e., bitumen extraction and upgrading). This implicit tax mimics a corporate income tax and represents investors requiring a greater rate of return to capital to invest in the oil sands. The implicit tax could also be considered a representation of the costs associated with other stakeholder challenges to the oil sands' social license to operate. Implicit tax rates of 2%, 10% and 15% were modelled under the Current Policies scenario, and the results were compared to a scenario where industry can avoid shareholder activism by adopting CCS. However, it is important to note that this is a simplifying assumption, since greenhouse gas emissions are not the only concern that has been raised about oil sands

[11] Holland S, Hughes J, Knittel C, 2009, "Greenhouse gas reductions under low carbon fuel standards?", *American Economic Journal*, 1:1 106-146.

developments, and the use of CCS alone is unlikely to fully eliminate the social challenges faced by oil sands developers.

Assumptions about CCS Availability

To gauge the economic benefits from CCS, we simulate each policy scenario under two assumptions about CCS availability – one in which CCS is available and another in which it is not available. The difference in economic performance between the two scenarios shows the benefit or cost from using CCS. In the scenario in which CCS is available, industry does not necessarily adopt CCS. Industry decides whether CCS is economical based on several criteria, including emissions pricing, the price for CO_2 used for enhanced oil recovery and the prices for energy and capital.

All tranches of CCS based on Jacobs' analysis are available in the model. The analysis also includes the option to employ CCS for small process heaters despite their high costs. These technologies are not adopted under most scenarios, but contribute to achieving deep reductions in greenhouse gas emissions.

Sensitivity Analyses

The initial analysis of the economic benefits from CCS availability is based on several assumptions about the cost and availability of CCS which are uncertain. To explore the impact of different assumptions about key assumptions, MKJA conducted sensitivity analyses on the following variables:

1. **CCS costs**
   Jacobs provided a range of costs for five applications of CCS. The initial analysis uses CCS costs based on the low end of each range plus 20%. This sensitivity analysis investigates full range of cost estimates for each technology provided by Jacobs.
2. **CCS Cost Declines over Time**
   Based on a literature review and discussions with steering committee, MKJA parameterized the analysis so the cost of CCS declines by 50% by 2030 under an aggressive adoption of CCS. The steering committee requested an additional scenario representing a more aggressive decline in costs over time due to technological breakthroughs. In this scenario, MKJA tested the impact of CCS costs declining by 50% by 2020 under an aggressive adoption of CCS.
3. **CCS availability**

   In the initial analysis, CCS becomes available to industry in 2016. To examine the impact of a later availability date, MKJA explores a scenario where CCS becomes available in 2021.

Summary of Forecast under Current Policies

The first step in the analysis was the construction of a reference scenario (the Current Policies scenario) to which all subsequent scenarios is compared. This scenario includes a number of current policies targeting greenhouse gases and energy consumption, as described above. To ensure the model provides a realistic simulation of Alberta's economy and emissions profile we compared the reference scenario to forecasts from various sources. This section summarizes the reference case forecast and discusses how it compares to other forecasts.

Macroeconomic Indicators

The analysis simulates the evolution of economic activity in Alberta, the rest of Canada and the United States from 2002 to 2030. Table 6 illustrates the key macroeconomic indicators from the forecast. Economic activity expands most rapidly in Alberta – at an annual 3.0% rate – and slightly more slowly in the rest of Canada (2.6%) and the United States (2.4%). Economic growth in the analysis is driven by several factors, of which the most important are:

1. Growth of the labour force, which is 1.5% per year in Alberta and 1.0% and 0.6% respectively in the rest of Canada and the United States. These assumptions are based on forecasts from Informetrica (2009) and the Energy Information Administration (2010).[12]
2. Labour productivity growth, which is assumed to be 1.8% per year in each region.[13]
3. The world price for commodities. In the analysis, we assume the world price for most commodities remains constant at 2002 levels, with the exception of light/medium oil prices. Table 6 shows that the price for light/medium oil rises from $77 per barrel in 2010 to $118 per barrel in 2030 (2002$ CDN). The price for raw bitumen is determined by explicitly representing the costs associated with upgrading bitumen into synthetic crude oil. These additional costs represent a $21 per barrel discount from a barrel of light/medium oil in 2030. By 2030, the price for bitumen reaches $97 per barrel.
4. Endowments of natural resources. Alberta is endowed with significant oil sands resources that can be extracted using either mining or in-situ operations. Endowments of other non-renewable resources (i.e., natural gas and conventional oil) are closer to depletion, and have limited to no room for further growth. Endowments of non-renewable resources have been adjusted so that

[12] Data for Canada is from Informetrica, 2009; Data for the United States is from Energy Administration Information (EIA), 2010, *Annual Energy Outlook, 2010*.
[13] EIA, 2010, *Annual Energy Outlook, 2010*.

the production forecast from GEEM approximates the latest forecast from the Canadian Association of Petroleum Producers.[14]

Table 6: Macroeconomic indicators

	2010	***2015***	***2020***	***2025***	***2030***	***Annual Increase (%)***
Real Gross Domestic Product (2002$ CDN billion)						
Alberta	172	195	227	266	312	3.0%
Rest of Canada	1,135	1,293	1,472	1,678	1,913	2.6%
United States	20,340	22,827	25,643	28,809	32,367	2.4%
Oil Prices (2002$ CDN / barrel)						
Light/medium oil	77	84	98	109	118	2.2%
Raw bitumen	59	65	79	88	97	2.5%
Natural gas prices (2002$ CDN / mmBTU)						
Natural gas	4.69	6.88	7.46	7.67	7.77	2.6%

Alberta's rapid growth in real gross domestic product growth (from $172 billion in 2010 to $312 billion by 2030 in 2002 $CDN) is mostly attributed to the expansion of the oil sands (see Table 7).[15] Bitumen extraction expands by 7.7% annually, which is significantly faster than the rest of Alberta's economy. Although the oil sands sector drives Alberta's economic growth, it also "crowds out" growth in other sectors. Expansion of bitumen extraction tightens an already tight labour market and leads to labour wage inflation in comparison to other jurisdictions. This reduces the competitiveness of trade-exposed sectors of the economy, resulting in stagnant or declining economic output in several manufacturing industries (e.g., chemicals and petroleum refining). Likewise, growth in the service and transportation sectors remains below the provincial growth rate, although these sectors are less exposed to trade.

[14] Canadian Association of Petroleum Producers, 2010, "2010-2025 Canadian crude oil forecast and market outlook", available from www.capp.ca.

[15] Real gross domestic product and all other values reported in dollars are calculated using a provincial fisher chain price index.

Table 7: Real gross domestic product in Alberta (2002$ billion)

	2010	*2015*	*2020*	*2025*	*2030*	*Annual Increase (%)*
Oil and gas						
Conventional oil extraction	10.3	8.4	7.4	6.3	5.3	-3.2%
Bitumen extraction	25.3	37.2	58.5	82.7	110.8	7.7%
Bitumen upgrading	1.5	1.9	2.4	2.8	3.6	4.3%
Natural gas extraction	14.5	18.9	18.4	17.7	16.5	0.7%
Other resource sectors	2.9	2.8	2.7	2.7	2.7	-0.3%
Electricity generation	1.4	1.9	1.9	2.0	2.1	1.9%
Manufacturing industry						
Chemicals	2.8	2.6	2.4	2.4	2.3	-0.9%
Non-metallic minerals	0.6	0.6	0.6	0.7	0.7	1.1%
Petroleum refining	1.9	1.7	1.5	1.2	1.2	-2.4%
Primary metals	0.3	0.3	0.3	0.3	0.3	0.3%
Paper	0.8	0.8	0.8	0.8	0.8	0.0%
Small manufacturing	6.2	5.9	5.8	5.9	6.0	-0.1%
Transportation	7.8	8.1	8.1	8.3	8.3	0.4%
Services	75.9	80.1	86.0	94.4	104.0	1.6%
Government	19.6	24.0	30.3	37.6	46.9	4.4%
Total	**171.8**	**195.2**	**227.1**	**265.7**	**311.5**	**3.0%**

As discussed above, Alberta experiences slower growth in industrial manufacturing than the rest of North America due to more rapid labour price growth. Table 8 shows that the price for labour grows 1.0% more rapidly in Alberta than in the United States, and 0.6% more rapidly than in the rest of Canada. Likewise, the price for intermediate goods grows more rapidly in Alberta than in the United States or the rest of Canada. This price growth renders trade exposed industries in Alberta less competitive and economic growth in these sectors is more moderate than in other jurisdictions.

Table 8: Labour and intermediate input price indices

	2002	*2010*	*2015*	*2020*	*2025*	*2030*	*Annual Increase (%)*
Labour price (1 = price level in 2002)							
Alberta	1.00	1.02	1.08	1.18	1.23	1.31	1.0%
Rest of Canada	1.00	0.99	1.03	1.06	1.09	1.10	0.4%
United States[16]	1.00	1.00	1.00	1.00	1.00	1.00	0.0%
Intermediate input price (1 = price level in 2002)							
Alberta	1.00	1.08	1.13	1.20	1.24	1.29	0.9%
Rest of Canada	1.00	1.02	1.03	1.05	1.06	1.07	0.2%
United States	1.00	1.00	1.00	1.00	1.00	1.00	0.0%

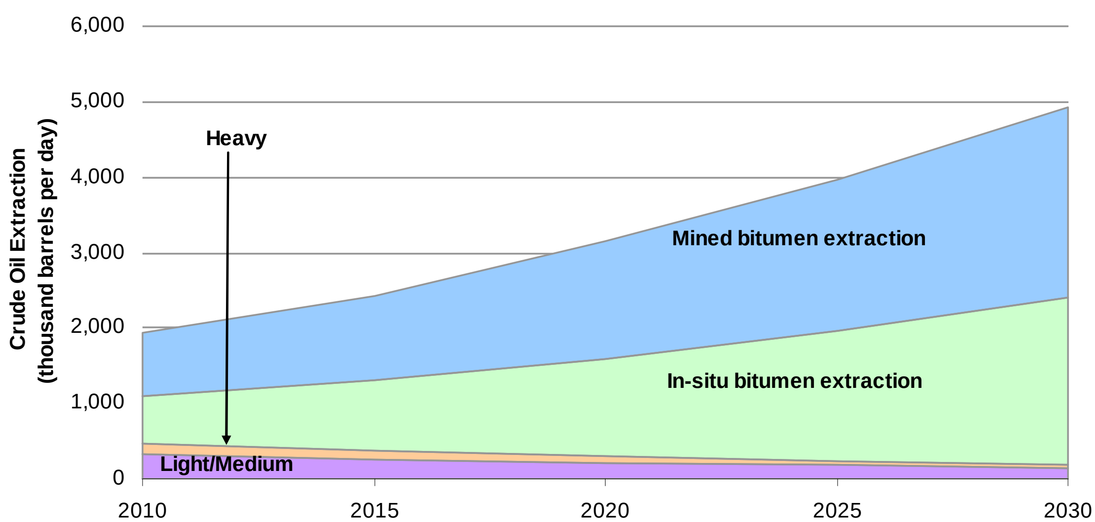
[16] For comparative purposes, the price indices for the United States are held constant at one.

Alberta's Energy Sector

Figure 2 shows the forecast for oil production in Alberta and Table 9 compares the oil and gas forecast to the Canadian Association of Petroleum Producers (CAPP).[17] GEEM simulates a gradual decline in conventional oil production, but rapid growth in both mined and in-situ bitumen extraction. By 2030, oil sands production amounts to 4,735 thousand barrels per day and accounts for 96% of Alberta's total oil production by volume. Although bitumen extraction expands rapidly in Alberta, the share of bitumen that is upgraded into synthetic crude oil declines over time. In 2002, 62% of bitumen extracted was upgraded, but this falls to 36% by 2030. The decline is a result of several factors, but is mostly due to increasing labour and input costs in Alberta in comparison to the rest of North America. Therefore an increasing amount of raw bitumen is exported to the United States (and potentially the rest of Canada in the future), where it is cheaper to upgrade and refine.

As the forecast from GEEM is based on the forecast from CAPP, the forecast here borrows the same assumptions about pipeline capacity and new markets. Specifically, it assumes the Keystone XL pipeline will be built, and there is likely to be excess pipeline capacity until 2022. After 2022, additional pipeline capacity would have to be built to accommodate growing production of crude oil from Alberta.[18]

Figure 2: Crude oil production in Alberta



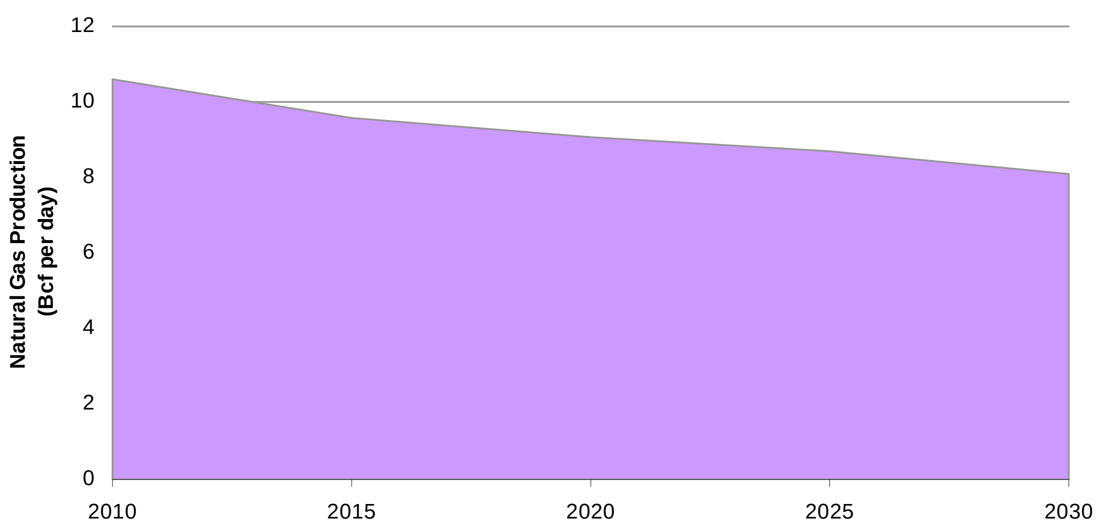
[17] Canadian Association of Petroleum Producers, 2010, "2010-2025 Canadian crude oil forecast and market outlook", available from www.capp.ca.
[18] Canadian Association of Petroleum Producers, 2010, "2010-2025 Canadian crude oil forecast and market outlook", available from www.capp.ca.

Table 9: Oil and gas production in Alberta

	2010	*2015*	*2020*	*2025*	*2030*	*Annual Growth 2002-2025 (%)*	
						GEEM	*CAPP*
Crude oil extraction (thousand barrels per day)							
Light/medium	318	261	215	176	145	-3.9%	-3.3%
Heavy	144	110	84	64	49	-5.2%	-5.3%
In-situ bitumen	638	930	1,281	1,719	2,214	7.9%	7.7%
Mined bitumen	831	1,138	1,568	2,014	2,521	6.3%	5.9%
Products from oil sands (thousand barrels per day)							
Raw bitumen	799	1,195	1,704	2,317	3,020	9.3%	8.7%
Synthetic crude oil	592	771	1,012	1,251	1,516	4.7%	4.3%
Natural gas extraction (Bcf per day)							
Conventional	7.7	6.5	5.5	4.6	3.9	-3.3%	NA
Unconventional	3.0	3.1	3.6	4.1	4.2	1.9%	NA

Natural gas production declines from 10.6 Bcf per day in 2010 to 8.1 Bcf per day in 2030 (see Table 9 and Figure 3). We assume natural gas production in Alberta is resource constrained in comparison to other natural gas resources in North America, and the decline occurs due to the depletion of existing wells. The decline in Alberta is offset by an expansion of production in the United States and the rest of Canada, where total natural gas production rises from 63.5 to 79.2 Bcf per day between 2010 and 2030. The expansion of natural gas production in the rest of North America is due to the development of shale and tight gas resources. Information on potential shale gas developments in Alberta was not available for this analysis, but could be included at a later date.

Figure 3: Natural gas production in Alberta (Bcf per day)



GEEM's growth for each type of oil production is similar to CAPP's forecast. A growth forecast for natural gas production was not available from CAPP, but GEEM's forecast is reasonably close to the forecast used by Alberta Finance. In 2013-2014 Alberta Finance forecasts natural gas production at 9.6 Bcf per day, compared with GEEM's production forecast of 9.8 Bcf per day.

The rapidly expanding production from the oil sands increasingly looks to markets in other provinces and the United States for export of surplus oil production (see Table 10). Exports of conventional/synthetic and raw bitumen expand considerably under current policies. Exports of conventional/synthetic oil rise at a 3.5% annual rate from 2010 to 2030; while raw bitumen exports rise by 6.9%. As discussed above, exports of raw bitumen grow more rapidly than synthetic oil because the costs of upgrading bitumen in Alberta rise more rapidly than in other jurisdictions. As a result, the portion of bitumen upgraded in Alberta declines, while other jurisdictions undertake greater upgrading.

Net exports of natural gas from Alberta gradually decline over time as production declines. By 2030, net exports of natural gas decline by 23% from 2010 levels.

Table 10: Net exports of energy commodities from Alberta

	2010	*2015*	*2020*	*2025*	*2030*	*Annual Increase (%)*
Crude oil (thousand barrels per day)						
Conventional and synthetic crude oil	662	673	817	1,029	1,325	3.5%
Raw bitumen	829	1,243	1,775	2,416	3,151	6.9%
Natural gas (Bcf per day)	8.5	7.5	7.2	7.0	6.6	-1.3%

Table 11 shows the production forecast for electricity generation in Alberta. Electricity generation expands from 66 TWh in 2010 to 109 TWh in 2030. Although generation from renewable resources increases its share of total generation – from 8.8% in 2010 to 10.6% in 2030 – Alberta remains heavily reliant on fossil fuels (mostly coal) to generate electricity under current policies. Utility generation also switches from natural gas to coal over time due to increasing natural gas prices. We note that this result is different from historic trends – in 2008 natural gas consumption by electric utilities was 151 PJ whereas the forecast here shows 89 PJ in 2008. The current policies forecast assumes that no new policies are implemented to reduce emissions from the electricity sector, whereas in reality utilities may be switching to natural gas to hedge against potential future policies to reduce emissions.

Table 11: Utility electricity generation forecast for Alberta

	2010	2015	2020	2025	2030	Annual Increase (%)
Production (TWh)						
Fossil Fuel	61	68	76	86	97	2.3%
Renewable	6	7	9	10	12	3.3%
Fossil Fuel Consumption (PJ)						
Coal	554	637	703	765	830	2.0%
Natural Gas	110	75	78	83	88	-1.1%

Provincial Government Revenues

The rapid expansion of Alberta's oil sands sector contributes to a significant growth in oil and gas royalties and revenues for the provincial government. Government revenues grow at a 3.9% annual rate between 2010 and 2030, mostly driven by a 6.1% increase in oil and gas royalties (see Table 12). Therefore, provincial government revenues become more dependent on the oil and gas sector over time. By 2030, 47% of provincial government revenues are from oil and gas royalties. Corporate and personal income tax revenues grow at rates closer to that of provincial GDP: 2.7% and 3.4% respectively.

The forecast for government revenues from GEEM is reasonably close to the forecast from Alberta Finance.[19] However, Alberta Finance's forecast for bitumen royalties is higher than from GEEM, while the natural gas royalty forecast is lower. Alberta Finance's higher bitumen royalty forecasts are a result of higher production forecasts – 2,357 thousand barrels per day versus 1,873 in GEEM. The GEEM model has been calibrated to CAPP's long-term forecast for bitumen production, which shows 2,015 thousand barrels per day of bitumen in 2013-2014. Natural gas royalties from GEEM are higher than forecasted royalties from Alberta Finance because the price for natural gas is higher in GEEM, although production between the two models is almost identical. Royalties from conventional oil are higher because the assumed royalty rate from GEEM is 20%. This is based on the long-term royalty rates for conventional oil recommended by Alberta Energy.

Government revenues forecast by Alberta Finance and GEEM are not completely comparable. GEEM does not include all sources of revenue to the provincial government. Specifically it excludes federal transfer payments, crown lease sales and investment income. The remaining sources of revenue account for approximately 76% of provincial government revenue. In the analysis, we assume that the uncovered 24% remains constant throughout the forecast period. Additionally, GEEM includes tax revenues paid to municipal governments, resulting in a higher forecast for "other indirect tax and subsidies" than Alberta Finance.

[19] Note that the forecast for tax revenues from Alberta Finance have been reported in 2002$. Alberta Finance, 2011, *Budget 2011 – Fiscal Outlook.*

Table 12: Provincial and municipal government revenues (2002$ billion)

	2010	*2015*	*2020*	*2025*	*2030*	*Revenues 2013-2014*	
						GEEM	*AB Fin*
Personal income taxes	7.2	8.2	9.3	10.7	12.3	8.0	8.0
Corporate income taxes	3.0	3.5	4.2	5.0	5.9	3.3	3.4
Provincial sales taxes	0.8	0.9	0.9	1.0	1.1	0.9	
Other indirect taxes and subsidies	5.7	6.1	6.8	7.6	8.6	6.0	
Oil and gas royalties	7.7	9.6	13.7	18.6	25.1	8.6	8.3
Conventional oil	2.3	1.9	1.6	1.4	1.1	2.0	1.5
Bitumen	3.2	5.2	9.7	15.0	21.9	4.3	5.7
Natural gas	2.1	2.5	2.4	2.3	2.1	2.4	1.2
Total revenues	**24.4**	**28.3**	**34.8**	**42.9**	**53.0**	**26.8**	

Table 13 shows the royalty rates that were modelled for each energy commodity over time. The royalty rates for conventional oil and natural gas are assumed to remain constant and are assumed to be insensitive to changes in oil prices. This assumption was used because the energy prices used in the analysis would result in close to the maximum royalty rate for conventional oil and gas. Royalty rates for bitumen rise with prices. These assumptions were developed in consultation with Alberta Energy.

Table 13: Royalty rates for oil and gas production

	2010	*2015*	*2020*	*2025*	*2030*
Royalty Rates (% of Gross Revenue)					
Conventional oil	20.0%	20.0%	20.0%	20.0%	20.0%
Bitumen	9.6%	10.8%	13.2%	14.8%	16.4%
Natural gas	10.0%	10.0%	10.0%	10.0%	10.0%
Oil Prices (2002$ per barrel)					
Light/medium oil	77	84	98	109	118
Bitumen	59	65	79	88	97
Natural gas (2002$ per mmBTU)	4.69	6.88	7.46	7.67	7.77

Greenhouse Gas Emissions

Greenhouse gas emissions in Alberta are forecast to rise rapidly in the absence of new climate policies. Between 2010 and 2030, greenhouse gas emissions grow by 38% to 305 Mt CO_2e (Table 14). Again, the rapid expansion of bitumen extraction and upgrading contribute most significantly to the increase in provincial emissions. By 2030, 41% of provincial emissions are from the oil and gas sector, with 26% from the electricity generation sector.[20]

[20] The current version of GEEM excludes emissions from agriculture and waste.

Table 14: Greenhouse gas emissions (Mt CO_2e)

	2010	2015	2020	2025	2030	Annual Increase (%)
Oil and gas						
Conventional oil extraction	10.7	8.4	6.6	5.1	3.9	-4.9%
Bitumen extraction	28.7	39.0	50.8	63.9	77.5	5.1%
Bitumen upgrading	10.9	13.9	17.5	20.9	24.4	4.1%
Natural gas extraction	30.3	26.9	24.7	22.7	20.5	-2.0%
Other resource sectors	2.8	3.0	3.0	3.0	3.0	0.3%
Electricity generation	55.9	61.8	68.0	73.8	79.9	1.8%
Manufacturing industry						
Chemicals	15.6	17.2	18.1	18.8	19.4	1.1%
GHG intensive industry	11.2	12.8	13.2	12.8	11.6	0.2%
Small manufacturing	8.3	8.6	8.2	7.9	7.7	-0.4%
Transportation	10.4	11.4	11.8	12.0	12.2	0.8%
Services	14.3	15.2	15.8	16.5	17.3	1.0%
Government	2.7	3.1	3.6	4.2	4.9	3.0%
Households	18.1	19.3	20.0	21.3	23.0	1.2%
Total	**220.0**	**240.5**	**261.2**	**282.8**	**305.2**	**1.6%**

Note: Some sectors show an increase in greenhouse gas emissions despite a reduction in their contribution to provincial income. This is due to Alberta's gross domestic product deflator rising significantly over time.

What Are the Benefits from Carbon Capture and Storage? Scenario Modelling Results

The economic benefits of CCS examined in this analysis include:

- Maintaining access to export market and the capital markets
- Impact on value-added industry
- Enhanced oil recovery
- Continued use of coal
- Other benefits, such as reputation and knowledge sector growth

The first four of these benefits were explicitly modelled by MKJA, and the results associated with each benefit are discussed below. The last category is discussed qualitatively, as these benefits cannot be quantified with the same degree of certainty as the first four benefits.

Maintaining Access to Export Markets and the Market for Capital

The benefit associated with CCS allowing continued access to export markets were modelled through two analyses: one in which the United States implemented a ban on new pipelines transporting oil sands crude to the United States, and a second in which the United States adopted a national low carbon fuel standard. This section also explores the implications of constraints on capital allocated to the oil sands sector due to shareholder activism.

In order to estimate the economic benefits associated with CCS, Alberta's economic activity with CCS available is compared with the province's economic activity when CCS is not available. The difference in economic performance between the two assumptions represents the benefit (or cost) associated with CCS.

Ban on New Oil Pipelines into the United States

Oil producers in Alberta currently access markets in the United States through a network of pipelines that transport crude oil to the Midwest region. Alberta currently has excess pipeline capacity to the United States with a total of 3,200 thousand barrels per day of capacity; and is expected to reach full capacity by 2017. The Keystone XL pipeline to the Gulf region is scheduled to begin operation in 2013 and add 700 thousand barrels per day of pipeline capacity. The additional capacity is forecast to meet supply until 2022.[21] After 2022, new pipelines to the United States are required to accommodate growth from the oil sands.

As discussed in the Policy Scenarios section of this report, the Keystone XL pipeline faces significant opposition from members of the U.S. Congress and other stakeholders in the United States. One of the main reasons for opposition to the pipeline is the high carbon intensity of crude oil produced from the oil sands, although other environmental issues are also a factor. The authority to approve Keystone XL rests with the U.S. State Department, which will issue a decision about whether or not it can proceed by November 1, 2011. If Keystone XL is not approved, Alberta crude production would lose access to an important market.

This analysis compares three scenarios:

1. CCS is not available to industry, and the United States implements a ban on new pipelines, starting with the Keystone XL pipeline;
2. CCS is not available to industry, and the United States implements a ban on new pipelines after the construction of the Keystone XL; and
3. Faced with a pipeline ban, the oil sands industry can adopt CCS to reduce the greenhouse gas intensity of their production and mitigate environmental concerns related to the oil sands in the United States. The adoption of CCS is assumed to avert a pipeline ban.

The assumption that industry's adoption of CCS would avert a pipeline ban is a simplification of the issue, as other environmental concerns about Keystone XL have also been raised and it is not certain that the adoption of CCS alone would be sufficient to avert a potential pipeline ban. Modelling the scenarios in this way allows us to understand the scale of a pipeline ban's potential impact, and CCS's potential role. An additional consideration is that pipelines to other exports markets (e.g., Enbridge's Northern Gateway project) would become more economic if new pipelines into the United States are banned. The purpose of this analysis is to estimate the value of export markets for crude oil and to examine whether CCS is an economic way of maintaining access to these markets. In consultation with the steering committee, we therefore assume new pipelines to British Columbia's west coast will not be built in response to a United States pipeline ban.

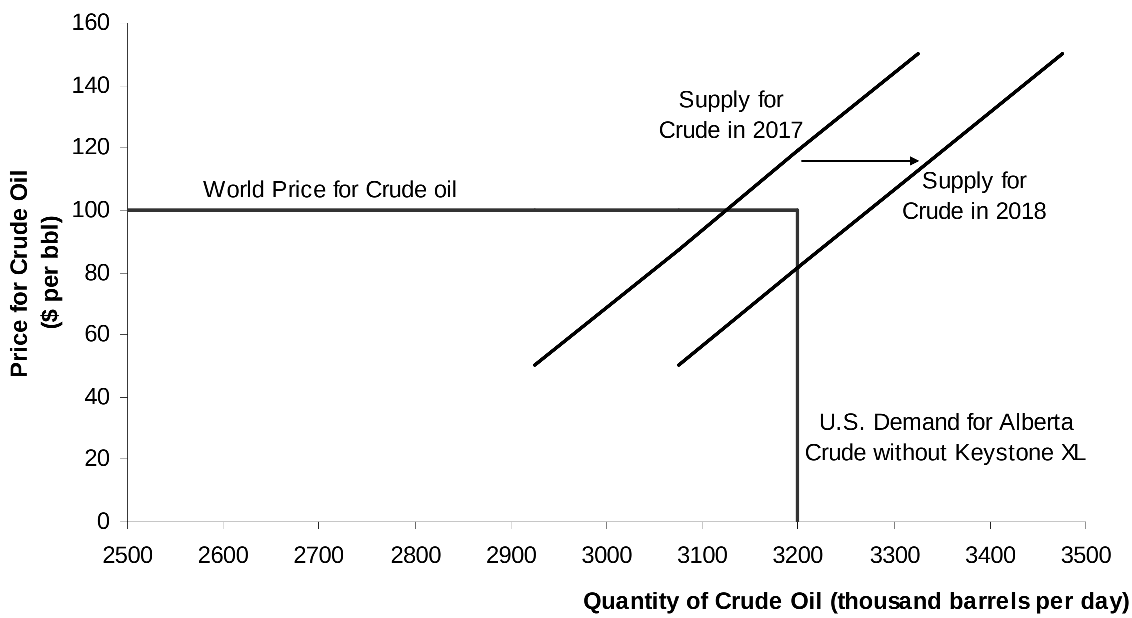
On a theoretical level, pipeline constraints create an "L" shaped demand curve for Alberta's petroleum in the United States (see Figure 4). The demand for Alberta's crude oil follows the world price (assumed to be $100 per barrel in the figure) until demand is constrained by the pipeline. After this point, U.S. refineries cannot purchase additional oil from Alberta and the demand curve turns downward. As crude capacity increases on an annual basis, the supply curve for Alberta's crude oil gradually shifts to the right. However, after 2017 additional crude oil supplies cannot be sold into the United States;

[21] Canadian Association of Petroleum Producers, 2010, *Crude oil forecast, markets and pipelines*.

and Alberta's crude production becomes decoupled from the world price. Refineries in the United States can demand lower prices for Alberta crude until supply into the United States stagnates.

If new pipelines into the United States are banned, Alberta can only increase crude oil production if it 1) reduces the exports of another type of crude oil (e.g., increase bitumen exports by reducing exports of synthetic crude oil), 2) accesses new markets in Canada (this analysis assumes that new pipelines can be built to the rest of Canada, but there is insufficient demand to absorb all of Alberta's crude oil production), or 3) increases domestic consumption.

Figure 4: Theoretical representation of crude oil market under pipeline constraints

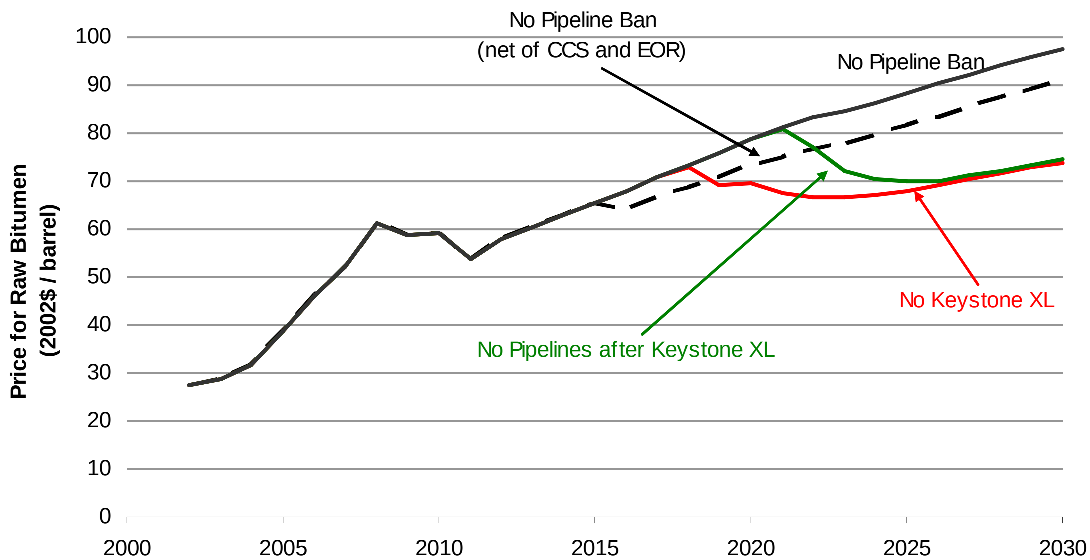


The result of the pipeline ban is a significant decline in the price of crude oil produced in Alberta. Figure 5 and Table 15 show the price for raw bitumen and synthetic crude oil under each of the three scenarios. Without the pipeline ban, the price for crude oil continues to follow the world price and reaches $98 and $124 per barrel of raw bitumen and synthetic crude by 2030. Prices are discounted heavily under the pipeline ban. If the Keystone XL pipeline is built but there is a ban on subsequent pipelines, the price for raw bitumen rises to $75 per barrel – a $23 per barrel discount; synthetic crude would have a $26 per barrel discount. If the Keystone XL pipeline is not built, the discount on oil sands products would be $24 and $27 per barrel of raw bitumen and synthetic crude respectively in 2030.

Although the price for crude oil in 2030 is similar under both pipeline ban scenarios, the price declines earlier if Keystone XL is not built. Under this policy, prices begin to diverge from the world price after 2017 whereas they begin to diverge after 2022 if subsequent pipelines are not built.

If the adoption of CCS by oil sands operators (i.e., in-situ and mined bitumen extraction and bitumen upgraders) prevents a pipeline ban, they would continue to sell their oil at the world price for oil but would experience additional costs from the adoption of CCS. These costs would be significantly lower than the discount caused by the pipeline ban. For in-situ bitumen extraction, the cost of CCS is forecast to be about $6.6 per barrel in 2030; while CCS implementation for bitumen mining and bitumen upgrading imposes a $1.1 and $1.2 per barrel cost respectively (see Table 15).

Figure 5: Price for raw bitumen with and without a pipeline ban (2002$ per barrel)



Note: For illustrative purposes, the dashed line represents the price for raw bitumen minus the cost of adopting CCS for in-situ bitumen extraction. The costs of CCS for mining bitumen and bitumen upgrading are less than the cost for in-situ bitumen extraction.

Table 15: Price for crude oil products (2002$ per barrel)

	2010	*2015*	*2020*	*2025*	*2030*
Price for Crude Oil (2002$ per barrel)					
Raw Bitumen					
No Pipeline Ban with CCS	59	65	79	88	98
No Keystone XL	59	65	70	68	74
No Pipelines after Keystone XL	59	65	79	70	75
Synthetic Crude					
No Pipeline Ban with CCS	80	87	102	113	124
No Keystone XL	80	87	92	90	97
No Pipelines after Keystone XL	80	87	102	93	99

	2010	2015	2020	2025	2030
Decline in Price (2002$ per barrel)					
Raw Bitumen (In-situ)					
Cost for CCS in No Pipeline	NA	NA	5.4	6.8	6.6
No Keystone XL	NA	NA	9.0	20.4	23.9
No Pipelines after Keystone XL	NA	NA	0.0	18.2	22.9
Raw Bitumen (Mined)					
Cost for CCS in No Pipeline	NA	NA	0.47	0.98	1.07
No Keystone XL	NA	NA	9.0	20.4	23.9
No Pipelines after Keystone XL	NA	NA	0.0	18.2	22.9
Synthetic Crude					
Cost for CCS in No Pipeline	NA	NA	0.9	1.2	1.2
No Keystone XL	NA	NA	9.9	22.7	27.1
No Pipelines after Keystone XL	NA	NA	0.4	20.4	25.9

Despite the pipeline ban, oil sands output remains relatively robust. Bitumen extraction grows by between 5.1% and 5.3% annually under the pipeline ban, whereas it grows by 5.6% with the adoption of CCS and avoidance of a pipeline ban. Bitumen upgrading is actually more robust under a pipeline ban than under the adoption of CCS (see Table 16). The trade patterns for crude oil and refined petroleum products in Canada would change significantly under a United States pipeline ban. Imports of light/medium crude into eastern provinces (i.e., Quebec and Ontario) would decline as they convert their energy systems to accommodate bitumen and synthetic crude oil from Alberta. Production of light crude oil in Newfoundland and other eastern provinces are likewise diverted to markets outside Canada as Canadians take advantage of lower priced crude oil from Alberta. Therefore, crude oil and refined petroleum products from the oil sands come to dominate Canada's market. Synthetic crude oil production under a pipeline ban actually exceeds production when CCS is available to avoid a pipeline ban scenario. Under a pipeline ban, more bitumen must be upgraded in Alberta or the rest of Canada to meet domestic demand. In other words, the share of bitumen upgraded in Alberta increases sufficiently to compensate for the lower bitumen extraction.

Despite the relatively robust production of bitumen and synthetic crude oil under a pipeline ban, the price Alberta producers receive for crude oil declines significantly. As a result, total gross domestic product in Alberta grows more slowly under the pipeline bans than under adoption of CCS. If the adoption of CCS allows for the Keystone XL to be built, cumulative gross domestic product between 2016 and 2030 would be $149 billion (2002$) greater when CCS is available. This represents a 3.0% increase from what Alberta's gross domestic product would have been when CCS is not available. If pipelines subsequent to the Keystone XL pipeline are not built without reducing the oil sand's greenhouse gas intensity, CCS would yield $83 billion more provincial income – a 2.1% increase. A discussion of the impacts on industry value added is available in the following section.

Table 16: Oil sands production (thousand barrels per day)

	2010	*2015*	*2020*	*2025*	*2030*	*Annual Increase (%)*
Raw Bitumen						
No Pipeline Ban with CCS	1,469	2,067	2,725	3,471	4,370	5.6%
No Keystone XL	1,469	2,067	2,782	3,324	3,957	5.1%
No Pipelines after Keystone XL	1,469	2,067	2,849	3,509	4,108	5.3%
Synthetic Crude						
No Pipeline Ban with CCS	592	771	893	1,002	1,157	3.4%
No Keystone XL	592	771	1,066	1,478	2,016	6.3%
No Pipelines after Keystone XL	592	771	1,011	1,381	1,928	6.1%

Low Carbon Fuel Standard

A low carbon fuel standard (LCFS) requires a reduction in the average greenhouse gas intensity of transportation fuels. Most LCFS policies proposed to date cover both upstream emissions (i.e., emissions from fuel production) and downstream emissions (i.e., emissions from direct combustion of fuels). Therefore, two main actions allow compliance with the LCFS. First, consumers of transportation fuels can substitute to low emissions intensity fuels. This can be achieved through direct consumer choice (e.g., a household fuelling their vehicle with low emissions intensity biodiesel as opposed to diesel) or as a result of refineries blending high intensity fuels with low intensity fuels (e.g., blending gasoline with Brazilian ethanol). Second, refineries and oil producers that supply fuel to the region under the LCFS can reduce their upstream emissions intensities, for example by adopting CCS.

An LCFS implicitly or explicitly imposes a tax on fuels with emissions intensities above the standard and acts like a subsidy for fuels with intensities below the standard. As transportation fuels produced from the oil sands have high emissions intensities in comparison to other forms of transportation fuels (e.g., light medium crude oil or cellulosic ethanol), the LCFS acts as a tax on products from the oil sands. For example, if gasoline produced from in-situ bitumen has a life-cycle emissions intensity of 110 g CO_2e per MJ and the standard calls for the average emissions intensity of transportation fuels to be below 85 g CO_2e per MJ, the implicit tax on bitumen would cover 25 g CO_2e per MJ of gasoline produced from bitumen.

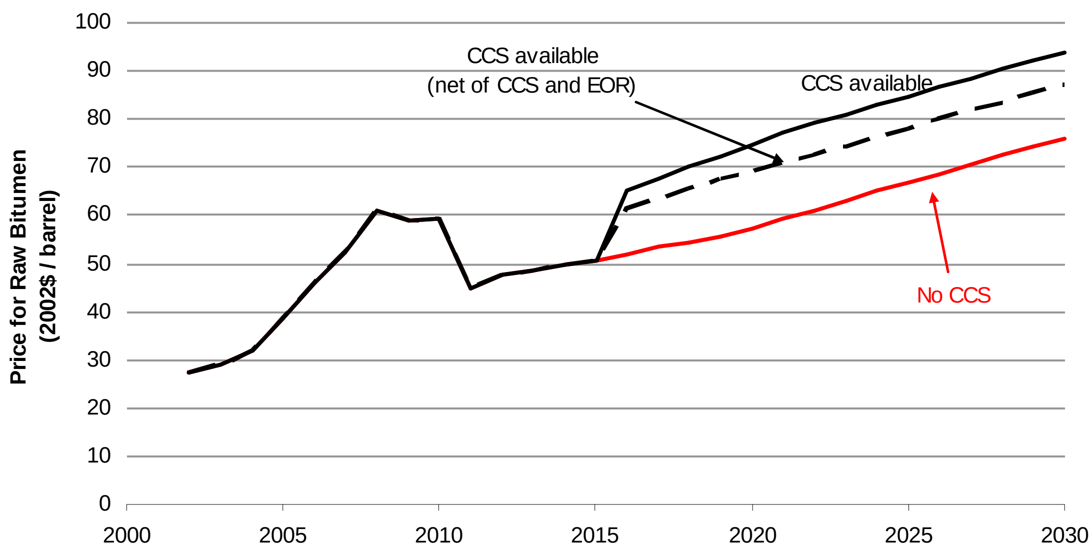
Relatively few studies to date have examined the economic effects of a LCFS, but Holland et al (2009) suggest the average abatement costs could be in the range of $309 to $2,300 per tonne CO_2e.[22] The lower end of this range represents more optimistic assumptions about the availability of low emissions intensity ethanol while the upper end represents less substitutability between low and high emissions intensity fuels. To assess the implications of an American LCFS on Alberta and to determine whether CCS

[22] Holland S, Hughes J, Knittel C, 2009, "Greenhouse gas reductions under low carbon fuel standards?", *American Economic Journal*, 1:1 106-146.

can ameliorate these impacts, we examine the low end of this range. While this may underestimate the impact of the LCFS, it is sufficient to show a benefit from CCS – if CCS is viable at the low end of the implicit tax range, the benefits would be greater at a higher implicit tax.

The implicit tax from the LCFS manifests itself by reducing the price that Alberta oil producers receive for exports into the United States. Figure 6 shows the average sales price for raw bitumen under current policies with a LCFS. Without the adoption of CCS, the price for raw bitumen rises to $76 per barrel by 2030, whereas it rises to $94 per barrel when CCS is available. Therefore the average sales price for bitumen is $18 per barrel higher under the adoption of CCS. The average sales price for synthetic crude oil is also $25 per barrel higher under the adoption of CCS (see Table 17).

Figure 6: Price for raw bitumen under a United States low-carbon fuel standard



Note: For illustrative purposes, the dashed line represents the price for raw bitumen minus the cost of adopting CCS for in-situ bitumen extraction. The costs of CCS for mining bitumen and bitumen upgrading are less than the cost for in-situ bitumen extraction.

The economic benefit or cost from adopting CCS under a LCFS is derived by comparing the decline in price from not adopting CCS to the direct cost of adopting CCS. Table 17 shows that the benefit from adopting CCS (greater prices for crude oil) exceeds the costs of adopting CCS. For in-situ bitumen extraction, prices for bitumen are around $18 per barrel higher under the adoption of CCS while the cost of adopting CCS is under $6.6 per barrel. The cost of adopting CCS for mined bitumen are lower than for in-situ bitumen extraction because 1) mined bitumen has lower emissions intensity and 2) fewer emissions can be easily captured. Similarly, the price for synthetic crude oil declines by $25 per barrel, while the cost of adopting CCS would only be around $1.2 per barrel in 2030.

Table 17: Price for crude oil products (2002$ per barrel)

	2010	2015	2020	2025	2030
Price for Crude Oil (2002$ per barrel)					
Raw Bitumen					
LCFS without CCS	59	51	57	67	76
LCFS with CCS	59	51	75	85	94
Synthetic Crude					
No Pipeline Ban with CCS	80	70	78	89	100
No Keystone XL	80	70	103	114	125
Net Decline in Price (2002$ per barrel)					
Raw Bitumen (In-situ)					
Decline from not using CCS	0.0	0.0	17.4	18.1	17.7
Cost of CCS	NA	NA	5.4	6.8	6.6
Raw Bitumen (Mined)					
Decline from not using CCS	0.0	0.0	17.4	18.1	17.7
Cost of CCS	NA	NA	0.5	1.0	1.1
Synthetic Crude					
Decline from not using CCS	0.0	0.0	24.6	25.4	25.3
Cost of CCS	NA	NA	0.9	1.2	1.2

As discussed in the section on pipeline bans, activity in the oil sands remains relatively robust despite the lower prices for bitumen and synthetic crude oil when oil sands producers do not have access to CCS (see Table 18). Trade patterns for crude oil in Canada change as a result of the policy, with oil sands products being diverted to other regions in Canada.

A more detailed discussion of the impacts on industry value added is available in the following sector, but CCS availability under a U.S. LCFS would add $149 billion to Alberta's gross domestic product between 2016 and 2030 – a 4.1% increase.

Table 18: Oil sands production (thousand barrels per day)

	2010	2015	2020	2025	2030	Annual Increase (%)
Raw Bitumen						
LCFS without CCS	1,469	1,843	2,307	2,916	3,680	4.7%
LCFS with CCS	1,469	1,843	2,507	3,236	4,112	5.3%
Synthetic Crude						
LCFS without CCS	592	864	1,219	1,622	2,113	6.6%
LCFS with CCS	592	864	1,392	1,894	2,503	7.5%

Shareholder Activism Targeting Alberta's Oil Sands

Shareholder activism is a growing concern for oil sands operators. At least five companies with major investments in the oil sands have been targets of shareholder activism over the past several years, with activist investors pressuring them to fully disclose and justify their involvement in the oil sands. There are concerns that shareholder activism could increase the cost of capital or lead to short-term capital shortages for oil sands producers.

In the long run, we do not expect shareholder activism to have a significant impact on the cost of raising capital for the oil sands. Investment in the oil sands represents a small share of global investment – based on 2005 data investment in the oil sands represents less than 2% of total investment in North America.[23] An increase in the cost of raising new capital would provide an opportunity for greater yields to investors, and at less than 2% of North American investment, the oil sands is unlikely to face a sustained shortage of new investors given the global mobility of capital. Higher rates of return in the oil sands would likely encourage a small number of investors to increase their investment in the oil sands. This dynamic would reduce rates of return to investment in the oil sands and return the cost of capital to around the global average.

However, in the short to medium term, it is possible that shareholder activism could lead major institutional investors to divest their oil sands-related investments, which could cause oil sands operators to face higher costs of capital. There are no estimates in the literature of the potential scale of this impact, and it is very difficult to predict exactly what impact (if any) shareholder activism will have on costs of capital. As a result, MKJA evaluated the impacts of a range of cost of capital increases on Alberta's gross domestic product and oil sands production, informed by research on other industries that have faced objections from socially-motivated investors. This research is discussed further in the Other Benefits of CCS section later in this report.

Increased costs of capital were modelled as an implicit tax imposed by global investors on capital allocated to Alberta's oil sands industries (i.e., bitumen extraction and upgrading). The implicit tax mimics a corporate income tax and represents investors requiring a greater rate of return to capital to invest in the oil sands. The implicit tax could also be considered a representation of the potential costs associated with other stakeholder challenges to the oil sands' social license to operate. Implicit tax rates of 2%, 10% and 15% were modelled under the Current Policies scenario, and the results were compared to a scenario which industry could avoid shareholder activism by adopting CCS. However, as previously mentioned this is a simplifying assumption, since greenhouse gas emissions are not the only concern that has been raised about oil sands developments, and the use of CCS alone is unlikely to fully eliminate the social challenges faced by oil sands developers.

Table 19 compares Alberta's gross domestic product under the three implicit tax scenarios on capital income from oil sands and under the CCS adoption/no implicit tax scenario. Even at the highest level modelled (15%), the implicit tax due to shareholder activism or other challenges to the oil sands industry's social license to operate would not be sufficient to warrant the adoption of CCS. Real gross domestic product is slightly

[23] Statistics Canada, 2009, CANSIM Table 381-0010; United States Bureau of Economic Analysis, 2011, "Input-Output Accounts".

lower under the CCS adoption scenario than under the three implicit tax scenarios, showing that the costs imposed by CCS slightly exceed the costs imposed by an implicit tax on capital income of 2% to 15%.

Table 19: Real gross domestic product in Alberta under an implicit oil sands capital tax (2002$ billion)

	2010	*2015*	*2020*	*2025*	*2030*	*Annual Increase (%)*
CCS adoption/No implicit tax	171.9	195.2	228.3	265.9	308.8	2.97%
2% implicit tax	171.9	195.2	227.0	265.6	311.3	3.02%
10% implicit tax	171.9	195.0	226.6	264.9	310.4	3.00%
15% implicit tax	171.9	194.8	226.4	264.5	309.9	2.99%

The results are similar for oil sands production. Bitumen production grows at 5.69% to 5.58% annually when subject to an implicit tax on capital ranging from 2% to 15%, and grows by 5.55% annually when producers are not subject to an implicit tax but are required to adopt CCS. (Under the Current Policies reference case scenario, with neither an implicit capital tax or a requirement for CCS adoption, bitumen production grows at a 6.03% annual rate). These results show that even significant increases in the cost of capital due to shareholder activism or other challenges to the industry's social license to operate would not push out marginal oil sands producers any more than the costs associated with adopting CCS.

Table 20: Oil sands production (thousand barrels per day)

	2010	*2015*	*2020*	*2025*	*2030*	*Annual Increase (%)*
CCS adoption/No implicit tax	1,334	1,827	2,469	3,138	3,934	5.55%
2% implicit tax	1,334	1,822	2,511	3,224	4,036	5.69%
10% implicit tax	1,334	1,802	2,481	3,182	3,984	5.62%
15% implicit tax	1,334	1,790	2,462	3,156	3,952	5.58%

Impact on Value-Added Industry

The analysis on maintaining access to markets in the United States indicates that the adoption of CCS would have a positive impact on value-added industry in Alberta. CCS would be an economic way of preventing American legislation that prohibits new pipelines into the United States. CCS would also be economic under an American low-carbon fuel standard. However, CCS does not appear to be a cost effective way to prevent increases in the cost of capital for oil sands producers due to shareholder activism.

In addition to policies that limit market access into the United States, CCS would be economic to stabilize or achieve deep reductions in greenhouse gas emissions in Alberta and Canada. This section examines the benefits or costs of CCS availability under economy-wide carbon policies of different strengths, represented by different targets for greenhouse gas emissions. In addition, it explores the impact on industrial value-added of policies to limit market access.

Economy-wide Policies to Reduce Greenhouse Gas Emissions

Emissions Pricing under Policy scenarios

The strength of policy required to achieve each target for greenhouse gas emissions must be stronger (measured by the emissions price in Table 21) when CCS is not available. Under emissions stabilization, the price for emissions rises to $88 per tonne CO_2e when CCS is available, whereas it rises to $118 per tonne when CCS is not available. So the policy to achieve emissions stabilization must be $30 per tonne CO_2e stronger in 2030 if CCS is not available. Under deep reductions, the policy must be $86 per tonne CO_2e stronger in 2030 without CCS availability - $292 versus $378 per tonne CO_2e. If CCS is not available to industry, several emissions intensive industries lack an economic means to reduce their emissions intensities, and must resort to more costly methods of reducing emissions. For example, if CCS is not available, alternative methods of reducing emissions include: 1) reducing output or 2) some industries can find alternative ways of reducing their emissions intensities (e.g., electrification or more aggressive fuel switching to low emissions fuels such as natural gas).

Table 21: Emissions prices (2002$ per tonne CO_2e)

	2011-2015	*2016-2020*	*2021-2025*	*2026-2030*
Current Policies				
CCS is not available	12	0	0	0
CCS is available	12	0	0	0
Emissions Stabilization				
CCS is not available	27	26	65	118
CCS is available	27	25	50	88
Deep Reductions				
CCS is not available	106	153	235	378
CCS is available	106	117	182	292

Economic Viability of CCS under Policy Scenarios

Under current policies, the incentive to reduce emissions is insufficient to warrant the adoption of CCS. After 2015, the emissions price under Alberta's specified gas emitters framework declines to $0 (i.e., industry in Alberta has meet its target under the policy), and there is no incentive to further reduce emissions intensity. However, there is a niche market to capture CO_2 to develop enhanced oil recovery (EOR). CCS can be adopted in the absence of climate policies if EOR fields offer a price for CO_2 that more than covers the cost of adopting CCS. Based on the EOR costs estimated from Jacobs, EOR systems become economic once the price for oil rises above $100 per barrel of light/medium oil.[24] As the price for oil is above $100 per barrel after 2020, niche applications of CCS are adopted to supply EOR fields with CO_2. By 2030, about 13 Mt CO_2 are captured from coal-fired electric power plants and bitumen upgraders to supply EOR fields.

As policies are implemented to reduce greenhouse gas emissions, the implementation of CCS becomes decoupled from the incentive to supply CO_2 for EOR. Under the deep reductions scenario, the emissions price is sufficiently high after 2015 – averaging $115 per tonne CO2e between 2016 and 2020 to warrant the adoption of the least cost applications of CCS. As the policy becomes more aggressive over time – rising to $289 per tonne CO_2e by 2026-2030 – all applications of CCS available to industry become economic. Under this scenario, CCS is an integral part of achieving the emissions target and is widely adopted across all sectors and applications.

Under emissions stabilization, CCS adoption is achieved through technology learning due to the initial adoption for EOR. Emissions pricing under this scenario only rises to the point where CCS is economic in the absence of EOR or cost reductions after 2025 (see Table 21). However, relatively high prices for CO_2-EOR in the medium term – 2020 – allow for the least cost applications of CCS to become economic earlier than 2025. Between 2016 and 2020, the policy to reduce emissions leads to a price of $25 per tonne CO_2e, but the price for CO2-EOR rises to $60 per tonne CO_2 by 2016. Therefore the combined incentive to adopt CCS from the policy and EOR is $85 per tonne CO_2e which is greater than the cost of adopting CCS for coal-fired generation.

As niche applications of CCS are adopted in the medium term to supply EOR fields, industry accumulates experience with CCS and costs decline. For example, the cost of CCS for coal-fired electricity plants is forecast to be $84 per tonne CO_2e in 2016 in the absence of CO_2 sales for EOR. By 2025 and 2030, the cost for coal-fired electricity declines to $74 and $70 per tonne CO_2e respectively. Learning on CCS in electricity generation benefits applications of CCS in other industries (e.g., for large process heaters in in-situ bitumen extraction), and applications of CCS become economic in these sectors as well. The result is that by 2022 several applications of CCS are adopted despite moderate carbon pricing.

Gross Domestic Product Impacts of CCS Adoption

CCS availability in Alberta stimulates gross domestic product under all policies scenarios. Under current policies, the availability of CCS would add $17 billion to Alberta's economy between 2016 to 2030; while under emissions stabilization and deep reductions CCS availability would add $37 and $126 billion (2002$) respectively. To put this into perspective, CCS availability has a small impact on the economy under current policies (cumulative gross domestic product increases by 0.4%), but the provincial income is 1.0% and 3.7% larger with CCS availability under emissions stabilization and

[24] Based on a $55 per barrel no-$CO_2$ cost for EOR, a 20% royalty rate on conventional oil and a $85 per tonne CO_2-EOR price (the cost of CCS for coal-fired electricity generation).

deep reductions. Figure 7 shows how each sector contributes to the increase in Alberta's cumulative gross domestic product and Table 22 summarizes Alberta's gross domestic product in 2030.

The largest beneficiary of CCS availability is the oil and gas sector. This sector contributes to about 60% of Alberta's improvement in economic performance under all policies. Under current policies and emissions stabilization, the benefit from CCS availability is primarily from enhanced oil recovery. Under current policies there is a small niche market for EOR, which adds 86 thousand barrels per day of conventional crude oil production between 2016 and 2030. Under emissions stabilization, EOR activity is more aggressive as the incentive to reduce emissions adds to the incentive to supply CO_2 for EOR. Under emissions stabilization, conventional oil production increases by 124 thousand barrels per day between 2016 and 2030 and oil and gas production adds about 24 billion to Alberta's gross domestic product between 2016 and 2030.

Under policies to reduce emissions, oil and gas production is particularly vulnerable to increases in the cost of production because these increases cannot be passed on to consumers. The price for oil is set in global markets in which Alberta is a price taker, so greater costs of production lead to a decline in production as marginal resources are not economic to develop. CCS availability reduces the cost of complying with a deep reductions policy, as the cost of adopting CCS is significantly less than the price for the policy – which rises to \$378 per tonne CO_2e when CCS is not available.

Figure 7: Increase in cumulative gross domestic product due to CCS availability (2016-2030)

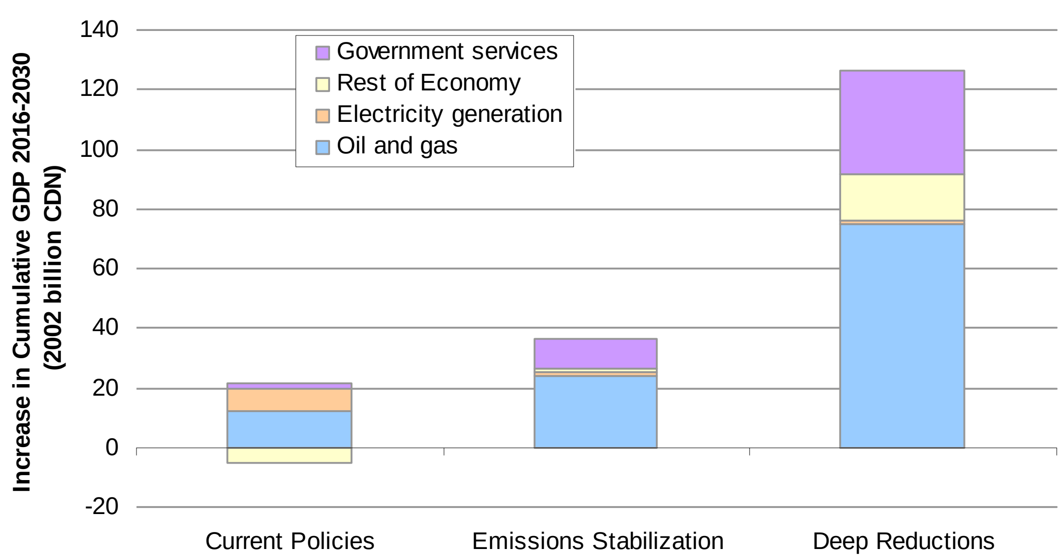


Table 22: Gross domestic product in Alberta in 2030 (2002$ billion)

	Current Policies		*Emissions Stabilization*		*Deep Reductions*	
	no CCS	*CCS avail*	*no CCS*	*CCS avail*	*no CCS*	*CCS avail*
Oil and gas						
Conventional oil extraction	5.3	6.5	5.3	9.4	5.2	7.2
Bitumen extraction	110.8	110.3	91.8	89.8	64.6	67.8
Bitumen upgrading	3.6	3.6	4.0	3.8	0.8	3.5
Natural gas extraction	16.5	16.5	17.8	17.9	18.5	18.6
Other resource sectors	2.7	2.8	3.6	3.7	5.5	5.0
Electricity generation	2.1	2.5	3.4	3.3	3.2	3.7
Manufacturing industry						
Chemicals	2.3	2.3	2.1	2.6	1.4	1.6
Non-metallic minerals	0.7	0.7	1.0	0.9	1.1	1.1
Petroleum refining	1.2	1.2	2.1	2.0	2.6	2.5
Primary metals	0.3	0.3	0.4	0.4	0.5	0.5
Paper	0.8	0.8	1.1	1.1	1.5	1.6
Small manufacturing	6.0	6.1	7.5	7.5	9.7	9.4
Transportation	8.3	8.4	10.7	10.6	14.4	13.6
Services	104.0	103.6	103.5	104.5	101.5	104.9
Government Services	46.9	46.8	38.0	39.6	27.7	31.1
Total	**311.5**	**312.3**	**292.4**	**297.2**	**258.2**	**272.2**

The supply of government services (e.g., health care) is closely linked to oil and gas production in Alberta because oil and gas royalties contribute to a significant portion of government revenues (see Table 23). Two factors contribute to greater oil and gas royalties under CCS availability. First, CCS enables greater oil and gas output. Under less aggressive policies to reduce emissions EOR enables an expansion of conventional oil production, while CCS can reduce the costs of complying with policies as they become more aggressive. Second, for a given level of production, the effective royalty rate on oil sands producers is lower if they are exposed to greater costs (from carbon pricing or CCS adoption). Royalty rates for oil sands are determined by the industry's net revenue (i.e., profits) rather than total revenue.[25] As carbon pricing imposes greater costs on industry when CCS is not available, net revenues and royalties per barrel of bitumen are lower.

In addition to lower royalties, receipts from personal and corporate income taxes are higher with the availability of CCS under emissions stabilization or deep reductions (see Table 23). These taxes are closely linked to the overall performance of Alberta's economy. As the availability of CCS enables more rapid economic growth under the

[25] Royalties for bitumen are based on gross revenue until the project's investment costs have been paid off. However, adding additional costs to the industry effectively extends the period required to pay off investment costs so CCS adoption still reduces the royalty rate per unit of gross revenue over the lifespan of the project.

emissions stabilization and deep reductions policies scenarios, receipts from these taxes are greater.

Table 23: Increase in government revenues due to CCS availability in 2030 (2002$ million)

	Current Policies	***Emissions Stabilization***	***Deep Reductions***
Personal Income Taxes	-56	307	769
Corporate Income Taxes	39	338	691
Provincial Sales Taxes	1	-5	-3
Other Indirect Taxes and Subsidies	-27	42	319
Oil and gas royalties	149	787	1,705
Total	**106**	**1,470**	**3,480**

The Rest of the Economy category in Figure 7 includes industrial manufacturing, oil and gas services, wholesaling/retailing, and other service industries. Activity from service industries is closely tied to Alberta's general economy and the oil and gas industry. CCS availability yields greater household income to spend on services such as restaurants. Likewise greater oil and gas output increases demand for oil and gas-related services. Industrial manufacturing was not significantly impacted the availability of CCS.

An additional factor that contributes to greater output from the rest of the economy from the availability of CCS is that electricity prices are significantly lower when CCS is available (see section on the Continued Use of Coal). This ensures that the industrial manufacturing sector and some services remain competitive with other jurisdictions.

Policies to Limit Market Access

Although most CCS applications are not economic under current policies, CCS becomes viable if its adoption ensures access to export markets in the United States. This section provides a more detailed exploration on the impact of an American low-carbon fuel standard and a pipeline ban on industry in Alberta.

Figure 8 shows the increase in Alberta's cumulative gross domestic product from 2016 to 2030 resulting from the availability of CCS. Under a low-carbon fuel standard, CCS would add $149 billion or 4.1% to Alberta's gross domestic product between 2016 and 2030. CCS availability mostly benefits the oil and gas sector and government services, which contribute to $244 billion and $53 billion to the greater economic output respectively. If Alberta can avoid a pipeline ban by adopting CCS, provincial income is between $83 and $111 billion greater between 2016 and 2030 with the availability of CCS. Again, the oil and gas and government sectors are the largest beneficiaries from CCS availability. As discussed in the section on market access, production from the oil sands as well as the price Alberta receives for its crude oil are greater if CCS is available. This leads to greater economic activity from the oil and gas sector as well as greater royalties for government.

While CCS has a positive impact on total economic output, industrial manufacturing and the service sector have lower output for two reasons. First, greater production of bitumen increases prices for labour and some intermediate inputs, which makes these sectors of the economy less competitive with other jurisdictions. As discussed in the section on the reference case scenario, Alberta's oil and gas sector grows substantially but growth in sectors such as industrial manufacturing is significantly lower (and even negative for some sectors). The rapid growth of bitumen extraction drives up the price for labour and other intermediates, rendering other sectors of the economy less competitive with jurisdictions. As a result, Alberta's economy becomes increasingly dependent on oil and gas production over time. A moderation of growth from the oil sand reduces total economic activity in Alberta, but improves the competitiveness of other industries due to lower wage rates. In particular, the small manufacturing industries experience more rapid growth if oil sands production is more moderate.

The chemical products sector would also benefit from lower prices for bitumen and other crude oil products if CCS is not available. Crude oil is a key input into Alberta's petrochemical products sector, so lower prices for crude oil in Canada relative to other jurisdictions leads to an improvement in competitiveness. Chemical products contribute between 5.0 billion and 12 billion less to Alberta's gross domestic product when CCS is available.

A second but less important factor that contributes to lower industrial output when CCS is available is that greater exports of crude oil (in both volume and price) raise Canada's exchange rate with the United States and the rest of the world. Under current policies, crude oil exports reach 20% of total Canadian exports. Therefore a small rise in oil exports causes a small but significant rise in Canada's exchange rate with the United States. In response, exports of other goods and services from Alberta (as well as the rest of Canada) become less competitive with goods produced in the United States and the rest of the world.

The result for industrial manufacturing is different from the economy-wide policies described above. In the economy-wide policies, CCS availability mitigates some of the increase in commodity costs. For example prices for electricity are lower due to CCS availability. This offsets some or all of the increases in labour and other commodity costs caused by greater oil and gas output. Additionally, lower crude oil prices relative to other jurisdictions under the market access policies when CCS is not available leads to an improvement of competitiveness for some sectors (most notably the chemical products sector). Under the policies to reduce emissions, the price for crude oil is the same across jurisdictions.

Figure 8: Increase in cumulative gross domestic product due to CCS availability (2016-2030)

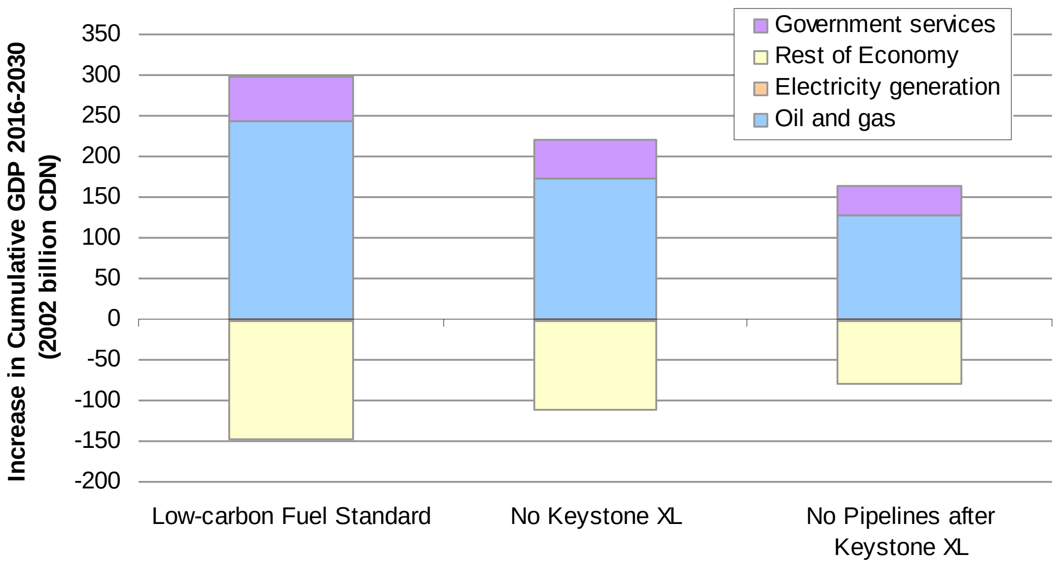


Table 24: Real gross domestic product in Alberta in 2030 (2002$ billion)

	LCFS		*No Keystone XL*		*No pipe after Key XL*	
	no CCS	*CCS avail*	*no CCS*	*CCS avail*	*no CCS*	*CCS avail*
Oil and gas						
Conventional oil extraction	6.3	10.5	6.3	10.5	6.4	10.5
Bitumen extraction	76.4	94.5	82.7	103.9	79.4	103.9
Bitumen upgrading	6.3	9.7	5.8	3.0	6.1	3.0
Natural gas extraction	20.8	17.3	20.3	17.1	20.6	17.1
Other resource sectors	4.6	3.1	4.4	3.0	4.6	3.0
Electricity generation	2.4	2.2	2.4	2.1	2.4	2.1
Manufacturing industry						
Chemicals	3.5	2.5	3.3	2.5	3.4	2.5
Non-metallic minerals	0.9	0.8	0.9	0.7	0.9	0.7
Petroleum refining	1.1	1.3	0.8	1.3	0.9	1.3
Primary metals	0.4	0.3	0.4	0.3	0.4	0.3
Paper	1.6	0.9	1.4	0.9	1.5	0.9
Small manufacturing	8.8	6.6	8.3	6.4	8.6	6.4
Transportation	11.6	9.0	10.9	8.8	11.2	8.8
Services	109.9	104.9	109.2	102.9	109.7	102.9
Government services	39.3	44.0	39.9	45.4	39.3	45.4
Total	**293.9**	**307.5**	**296.9**	**308.8**	**295.2**	**308.8**

Enhanced Oil Recovery

One option for disposing of CO_2 is to use it for enhanced oil recovery (EOR). The potential economic benefits from EOR include:

1) A potential revenue stream from the sale of CO_2 could offset some or all the costs of capture; and

2) An increase in oil output due to EOR would increase economic output and royalties from conventional oil production.

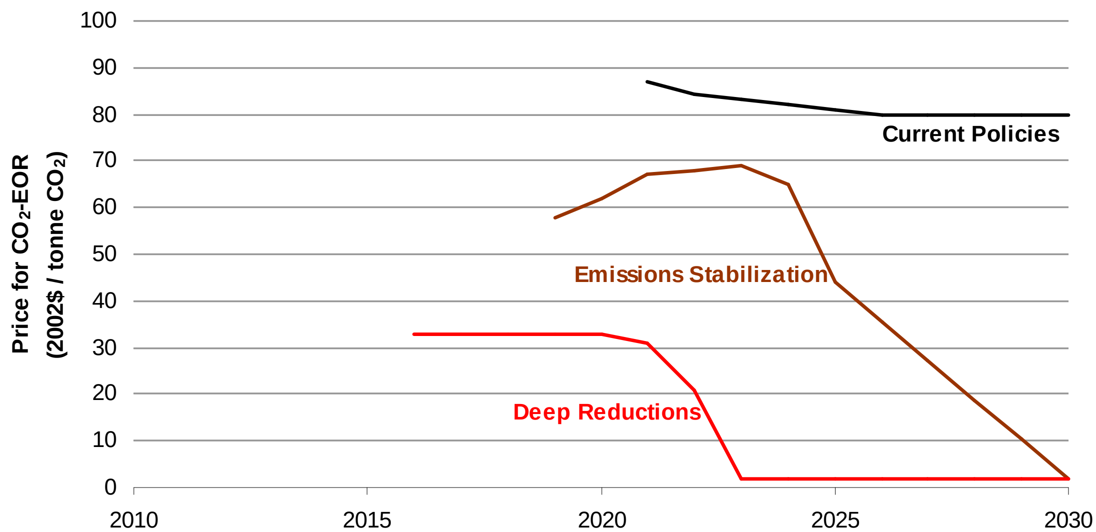
Reducing the cost of CCS

Carbon dioxide captured from CCS can be sold to oil fields for use in EOR, which offsets some or all of the costs associated with adopting CCS. The price of CO_2 sales for EOR shows the degree to which the costs for CCS can be reduced. For example, if it costs $85 per tonne CO_2e to adopt CCS, but an EOR facility offers $25 per tonne the net cost of adopting CCS is only $60 per tonne.

Figure 9 shows the projection of CO_2-EOR prices in three of the climate policy scenarios (the prices for CO_2-EOR under the policies to limit market access are not shown in Figure 9 for simplicity, but are available in the appendix). The price for CO_2-EOR depends on the level of aggressiveness to reduce greenhouse gas emissions. Under current policies CCS is adopted for the sole purpose of supplying EOR fields, so the price for CO_2-EOR remains high to ensure a constant supply. Under economy-wide climate policies, CCS is adopted to reduce emissions in addition to supplying CO_2 for EOR. For example, the cheapest applications of CCS are for coal-fired electricity generation at about $85 per tonne CO_2e. Under current policies, the price for CO_2-EOR must higher than this cost for CCS to be adopted and for the market for CO_2-EOR to originate. As policies are implemented to reduce emissions, CCS can be achieved at a lower CO_2-EOR price as the price for emissions under the policy adds to the incentive to supply CO_2 to EOR fields. During the medium term under emissions stabilization (2020) the price for the emissions stabilization policy is about $25 per tonne, which enables a lower CO_2-EOR price of $60 per tonne to achieve the adoption of CCS. Likewise under the deep reductions policy, the price for CO_2-EOR can be significantly lower during the initial phases of CCS adoption – around $33 per tonne CO_2.

Under emissions stabilization and deep reductions, the supply of CO_2 is eventually decoupled from the incentive to supply EOR. The maximum capacity for EOR to absorb CO_2 is about 24 Mt, so once the supply from CCS exceeds this amount the price for CO_2-EOR no longer provides a benefit to CCS plants. In Figure 9, the price for CO_2-EOR declines to the incremental cost of transporting CO_2 to an EOR field from a capture site, which is assumed to be small as EOR sites are in approximately the same locations as saline storage sites.

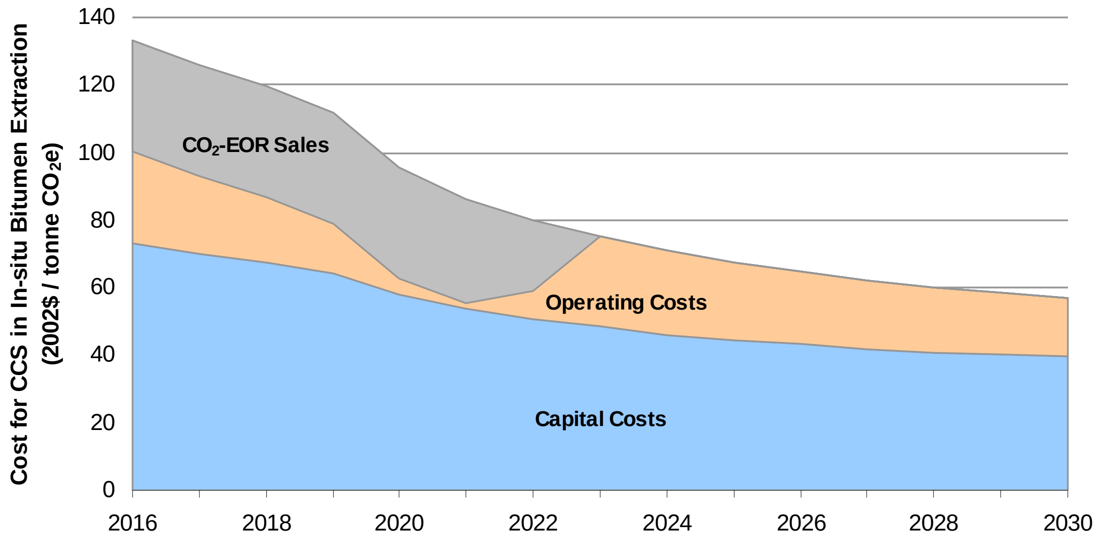
Figure 9: Price for CO_2 used for enhanced oil recovery



Although CO_2 sales for EOR may not provide a direct benefit to the CCS plant after prices have crashed (by 2023 in the deep reduction scenario), CO_2 sales offset the costs of CCS in the near term when they are at their highest point. As a result, they facilitate manufacturers' accumulation of experience with the technology and act as a bridge to a period when CCS costs are lower. To date, experience with CCS at a commercial scale is limited to a few facilities worldwide, of which none are located in Alberta. With limited knowledge of how to install and operate a CCS plant, the first plant is likely to be the most costly. Subsequent plants benefit from the experience gained from installing the first plant and experience lower capital and operating costs.

Figure 10 shows the cost for CCS at an in-situ bitumen extraction facility. The top of the stack of wedges indicates the cost for CCS if EOR were not available, while the grey wedge indicates the benefit from CO_2 sales. The total cost for CCS in in-situ bitumen extraction is $133 per tonne CO_2e in 2016, but EOR sales reduce this cost by $33 per tonne to $100 per tonne. By 2023 under the deep reductions scenario, the price for CO_2 has declined to the incremental cost of transporting CO_2 to an EOR site and no longer provides a benefit to CCS adoption. However, over this period capital costs for CCS have declined by 34% and operating costs have declined by 59%, bringing the total costs for CCS in in-situ bitumen extraction down to $75 per tonne CO_2e. The benefit of EOR is that the net costs for CCS in in-situ bitumen extraction never exceed $100 per tonne CO_2e.

Figure 10: Benefit to CCS plant from CO_2 sales for EOR (2002$ / tonne CO_2e)



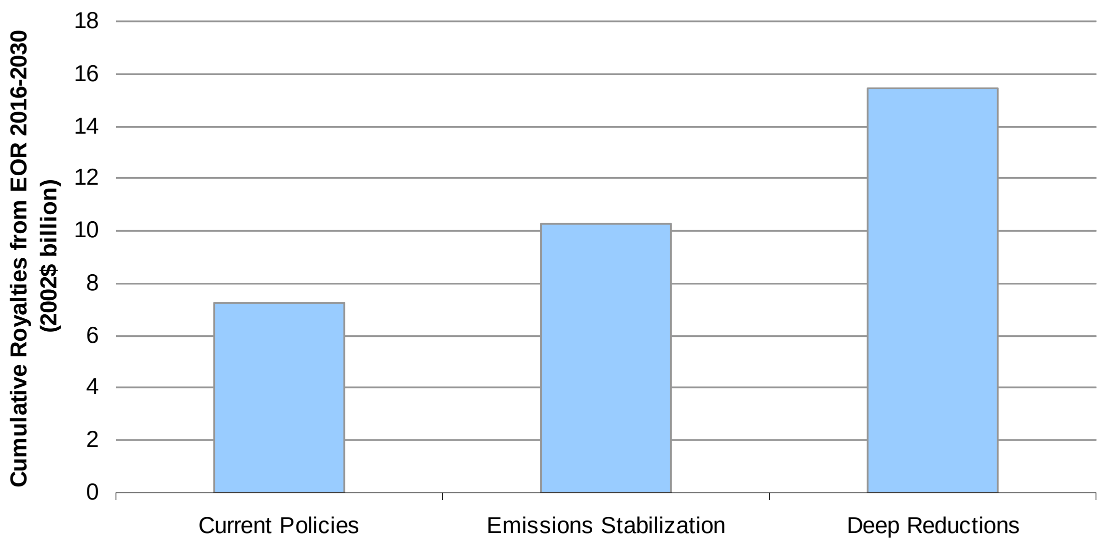
Note: The costs for CCS in in-situ bitumen extraction are higher in 2016 than shown in Table 1. The costs in Table 1 show the costs in 2002, but prices for natural gas increase between 2002 and 2016 leading to higher CCS costs.

Increasing conventional oil production

While CO_2 sales provide a benefit to facilities adopting CCS in the near-term, the supply of cheap CO_2 in the long-term allows for continued development of EOR. This stimulates conventional oil production. Between 2016 and 2030, conventional light/medium oil production increases by between 86 and 197 thousand barrels per day. Under current policies only the least cost applications of EOR are adopted by industry and EOR is implemented later in the simulation (after 2021). Therefore, EOR adoption is more limited than under emissions stabilization or deep reductions where the supply of CO_2 for EOR is decoupled from the demand from oil fields. Details on the increased economic activity from EOR are available in the section on Impact on Value-Added Industry.

In addition to greater economic activity from conventional oil production, greater oil production from EOR increases total royalties collected by government (see Figure 11). Cumulative royalties from EOR amount to between $7 and $15 billion (2002$) between 2016 and 2030, or between $500 and $1,100 million on an annual basis.

Figure 11: Cumulative royalties from EOR between 2016 and 2030 (2002$ billion)



Continued Use of Coal

Alberta is endowed with significant coal resources which it uses to generate about 73% of its electricity, and which contribute to 20% of the province's greenhouse gas emissions.[26] Achieving reductions in greenhouse gas emissions from electric generation requires utilities to either switch to low- or zero-emissions fuels (natural gas or renewable resources) or to adopt CCS at coal- and/or natural gas-fired power plants. A potential benefit from adopting CCS is that the continued use of coal could:

1) Maintain lower electricity prices under a climate policy scenario;

2) Allow for greater natural gas exports to other jurisdictions; and

3) Increase economic output from the coal mining sector.

Maintaining lower electricity prices

CCS availability maintains lower electricity prices under policies to reduce emissions. Figure 12 shows the price for electricity prices in each of the policies to reduce greenhouse gas emissions. Under current policies, the price for electricity are mostly unaffected by the availability of CCS; while under emissions stabilization and deep reductions, the availability of CCS reduces prices for electricity by $10 and $50 per MWh in 2030. Lower electricity prices under emissions stabilization and deep reductions are due to two factors. First, CCS removes exposure to the carbon policy as both coal- and natural-gas fired electric generation have lower emissions intensities. Under both

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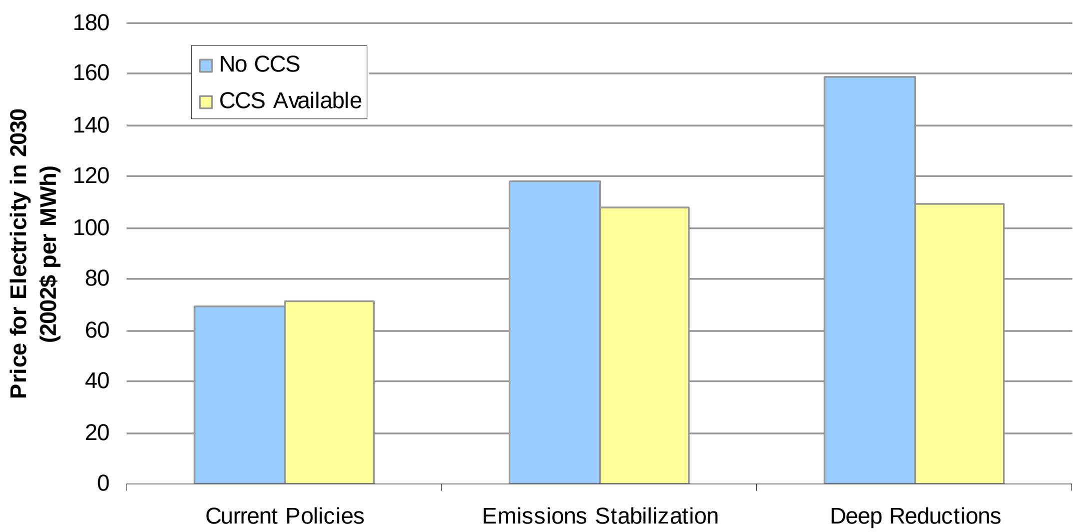
[26] Based on utility generated electricity. Statistics Canada, 2009, *Electric power generation, transmission and distribution 2007*; Environment Canada, 2010, *National inventory report*.

policies the price for electricity is about the same when CCS is available, indicating that electricity prices have been decoupled from the carbon policy.

Second, in the absence of CCS, the electricity sector must reduce emissions by switching away from coal to either natural gas or renewable resources. As coal has a lower price per unit of energy, CCS availability for coal-fired generation maintains lower energy costs.

The price for electricity under current policies is slightly higher with CCS availability. The limited development of EOR under current policies leads to slightly greater electricity demand and price.

Figure 12: Electricity prices in 2030 (2002$ / MWh)



An additional benefit from the continued use of coal that has not been captured in the modelling is that prices for coal-fired electricity are more stable than prices for natural gas-fired electricity. Between 2002 and 2011, natural gas prices have ranged from $1.60 to $14.38 (2002 $USD / mmBTU).[27] Therefore, the energy costs alone from natural gas-fired generation ranged between $10 / MWh and $90 / MWh.[28] Volatile electricity prices can reduce economic growth because electricity intensive industries (e.g., oil pipelines or iron and steel production) have difficulties determining the optimal investment in energy efficiency or which fuel to consume. Likewise, volatile electricity prices affect the amount of household income available to purchase other goods and services. An electricity system with greater dependence on coal would experience significantly less volatility than one dependent on natural gas, as coal is more abundant and coal prices are more stable.

[27] Based on the Henry hub spot price. Energy Information Administration, 2011, available from www.eia.doe.gov.

[28] Based on a combined cycle natural gas turbine with an efficiency of 52%. CIMS, 2011.

Increasing natural gas exports

In theory, the continued use of coal could raise natural gas exports. The availability of CCS would reduce the need to switch away from coal-fired generation to generation from low- and zero-emissions fuels (e.g., natural gas or renewable resources). Therefore, natural gas consumption by electric utilities could theoretically be lower if CCS is available, allowing the excess natural gas to be exported. However, the analysis suggests that natural gas consumption by electric utilities would rise under policies to reduce emissions if CCS is available. With CCS, the share of natural gas consumption in total fossil fuel generation declines, but total fossil fuel generation increases. This latter effect more than offsets the former and the net impact of CCS availability is to increase natural gas consumption (see Table 24). Natural gas available for export only slightly increases under current policies when the electricity sector invests in coal-fired power plants with CCS to supply CO_2 to EOR fields.

Table 25: Natural gas consumption by the electricity sector in 2030 (PJ)

	Current Policies	*Emissions Stabilization*	*Deep Reductions*
no CCS	88	67	16
CCS	84	79	80
Natural Gas available for Export	**3**	**-13**	**-64**

Increasing economic output from the coal mining sector

Coal-fired generation with CCS could maintain stronger economic output from the coal mining sector; however the benefits from this are small in comparison to the economic output from the rest of the economy. Table 26 shows the economic output of the coal mining sector in Alberta in 2030. The economic output from coal mining is dependent on the level of greenhouse gas policy. Under current policies the adoption of CCS has a negligible effect on the coal mining sector. However, under the emissions stabilization and deep reductions scenarios, GDP from the coal mining sector increases by 24% and 18% respectively with the availability of CCS.

Table 26: GDP produced by the coal mining sector in 2030 (2002$ million)

	Current Policies	*Emissions Stabilization*	*Deep Reductions*
no CCS	289	201	304
CCS	290	249	357
Increase in GDP	**0%**	**24%**	**18%**

The increase in GDP from coal mining should be put into the perspective of the wider economy. Coal mining represents about 0.1% of Alberta's total economy in 2030, so increases or decreases in this sector have limited effect on overall economic performance.

Sensitivity Analyses

The analysis above identified that CCS can improve economic activity if Canada aims to stabilize or achieve its targets for greenhouse gas emissions. It also indicated that CCS availability would maintain stronger economic output if policies are enacted to limit access of Alberta crude into the United States. These results are based in part on assumptions about uncertain parameters. In order to explore the impact of different assumptions about the value of key variables, MKJA conducted sensitivity analyses on:

1. **CCS costs**. Jacobs provided a range of cost estimates for CCS as shown in Table 1. This section explores the implications of the low and the high estimates for CCS costs.
2. **CCS Cost Declines over Time**. In the analysis above the model was parameterized to ensure CCS costs decline by about 50% by 2030 under an aggressive adoption of CCS. In this section, we explore the implications of a 50% decline by 2020.
3. **Delay in CCS implementation**. In the analysis above, CCS is becomes available in 2016. In this section we examine the impact of CCS becoming available in 2021.

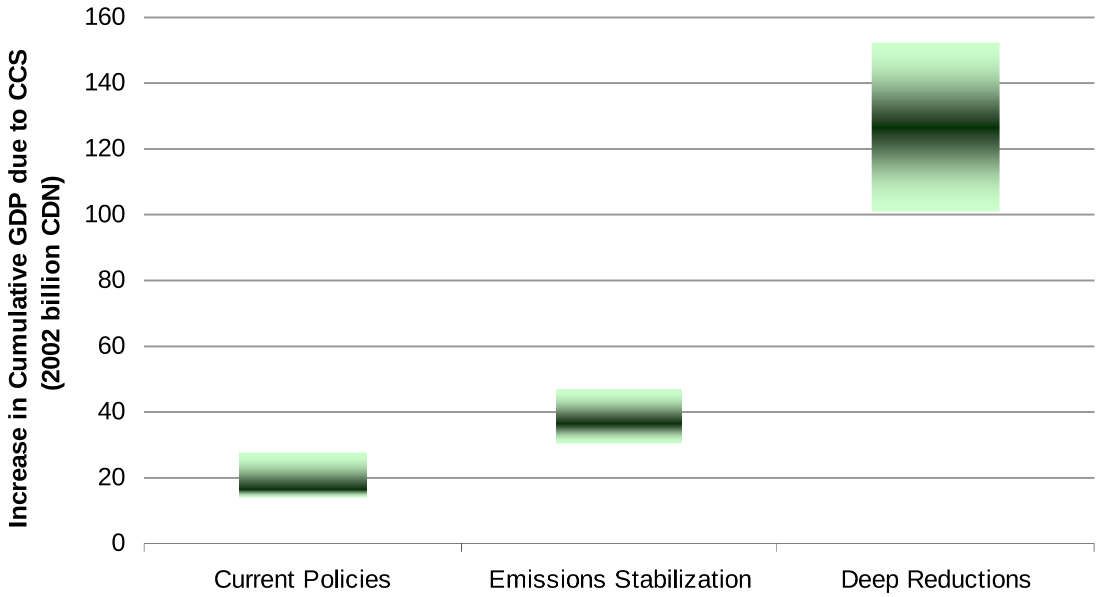
The results for each of these sensitivity analyses are summarized below.

CCS Costs

Jacobs provided a range of costs for each application of CCS. The base value for CCS in the analysis above used the low cost plus 20%. The high costs from Jacobs are generally between 30% and 47% above the base value used in the range. The exception is CCS applications for small process heaters, which have high costs 100% above the base value, but these applications receive limited market share in the analysis and cover only small quantities of emissions.

Figure 13 shows the increase in cumulative gross domestic product between 2016 and 2030 due to CCS availability under the emissions reductions policies. The results show that CCS would benefit Alberta's economy under the full range of CCS costs, but higher CCS costs would lead to fewer benefits while lower CCS costs would lead to greater benefits. Under current policies, lower CCS costs would enable EOR to be developed earlier and at lower cost, this would add $27 billion to Alberta's economy between 2016 and 2030 – an $11 increase over the base value. If costs are higher, EOR is developed later and at higher cost and CCS only adds $14 billion to Alberta's economy – a $2 billion reduction from the base values. Under emissions stabilization, the range of economic benefits corresponding to the range of CCS costs is between $31 and $47 billion between 2016 and 2030. As discussed above, the benefits from CCS under emissions stabilization are still concentrated in the benefits from EOR. However, at the lower cost range CCS is increasingly used to reduce emissions in addition to supply CO_2 for EOR.

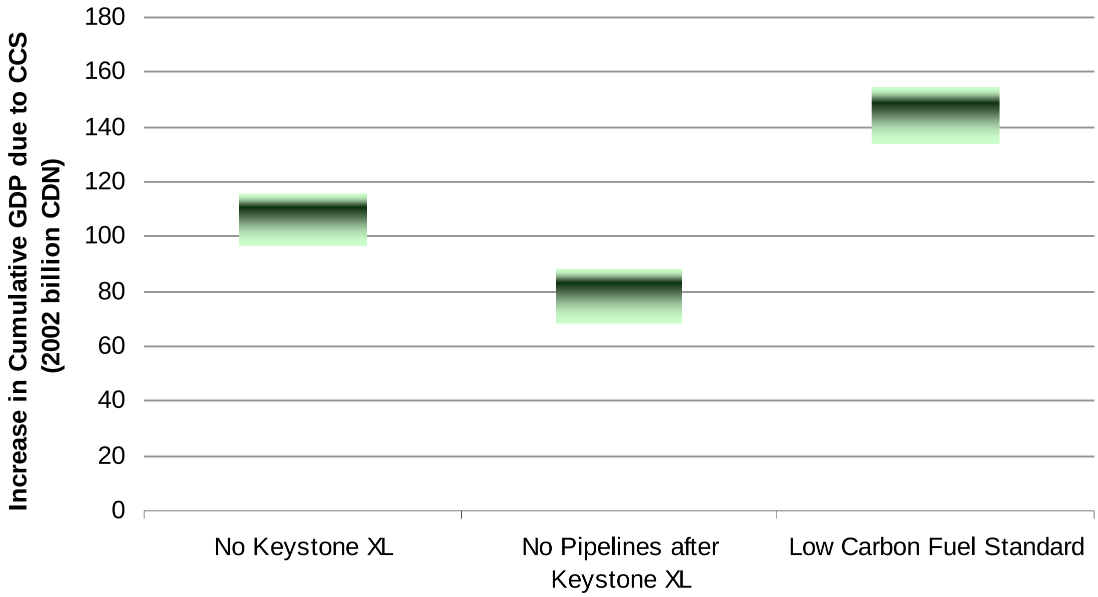
Figure 13: Range of cumulative GDP increase due to CCS under the range of CCS costs – policies to reduce greenhouse gas emissions



The range is wider under the deep reduction policies scenario – GDP is between $101 and $152 billion greater when CCS is available. The range of CCS benefits is wider under the deep reductions scenario because Alberta's economy relies on CCS more heavily to achieve the emissions target. Higher CCS costs increase the cost of complying with the policy and lead to more moderate growth in the oil and gas sector. In turn, more moderate growth in the oil and gas sector reduces royalties collected by government. Additionally, higher CCS costs lead to greater electricity prices which reduces competitiveness throughout the economy. On the other hand if CCS costs are lower, CCS reduces costs of complying with the deep reductions policy.

The direction of economic benefits from CCS is also insensitive to the range of CCS costs under policies to limit market access (see Figure 14). The economic benefits under the full range of costs are a maximum of $14 billion or 17% different from the base value. Therefore, the economic benefits from CCS are positive under the full range of CCS costs. To put the high costs into perspective, an American low-carbon fuel standard reduces the price on raw bitumen by $18 per barrel whereas at the high end of the range, CCS costs around $9 per barrel for in-situ bitumen extraction in 2030. Therefore, CCS continues to provide an economic benefit despite the higher costs. The same applies for the pipeline ban scenarios, which reduce the price for raw bitumen by between $23 and $24 per barrel in 2030.

Figure 14: Range of GDP increase from CCS under different costs for CCS – policies to limit market access



CCS Cost Declines over Time

The analysis assumed the costs for CCS would decline by 50% by 2030 under an aggressive adoption of CCS. However, this relationship is uncertain and the steering committee requested a sensitivity analysis to examine a more rapid decline in CCS costs over time. In this section we explore the impact of CCS costs declining by 50% by 2020 under an aggressive adoption of CCS.

Figure 15 shows that under the emissions stabilization scenario, capital costs for CCS in in-situ bitumen extraction only decline to $109 per tonne CO_2e using the base setting, but decline to $60 per tonne CO_2e under a more aggressive cumulative learning rate. Under the deep reductions policy scenario, costs decline fully by 2030 regardless of the aggressiveness of the decline function.

Figure 15: Decline in CCS costs under emissions stabilization and deep reductions

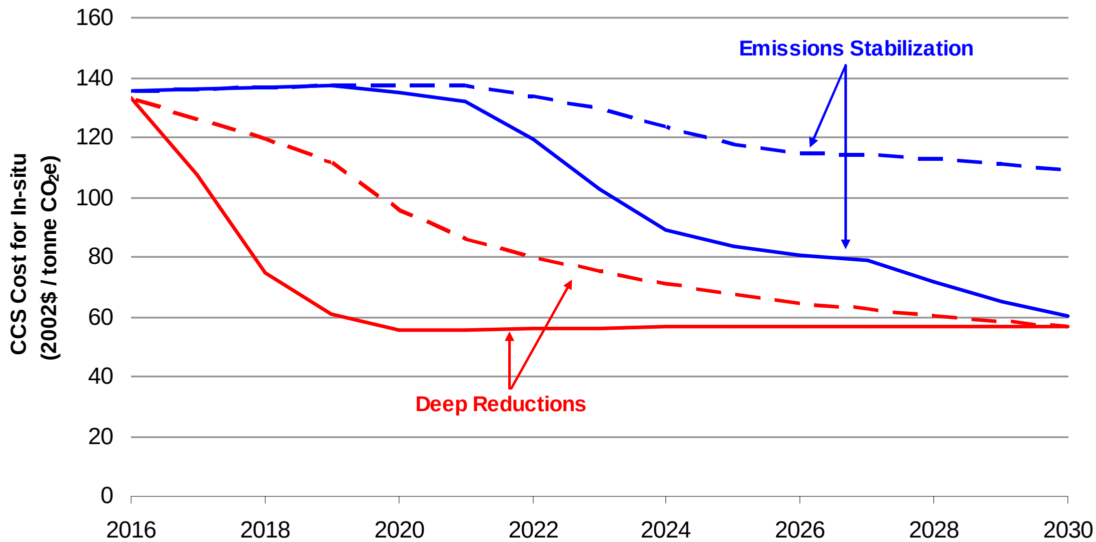
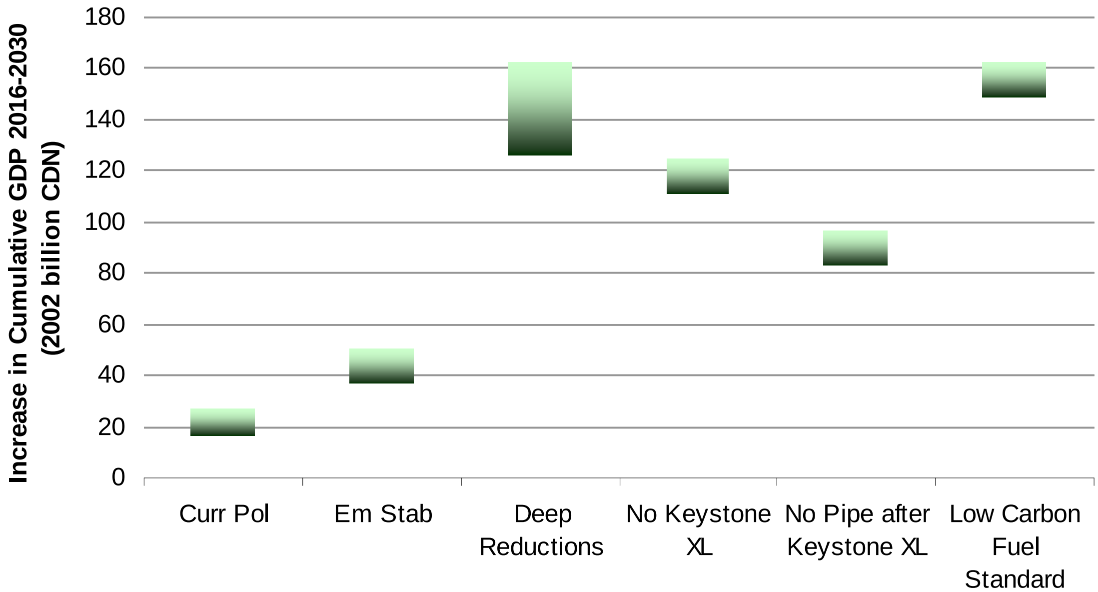


Figure 16 shows the improved economic activity due to CCS availability under the two assumptions for declines in CCS costs. The bottom of each wedge indicates the economic benefit under the less aggressive decline while the top indicates the benefit under the more aggressive decline. A more aggressive decline in CCS costs yields greatest benefits to Alberta's economy under more aggressive climate policies. Under this policy, CCS availability would add an extra $36 billion to provincial income between 2016 and 2030 if CCS declines are more rapid.

Under current policies, CCS is adopted as a small niche to supply CO_2 for EOR and this small penetration of the technology does not lead to significant declines in costs under either assumption about cost declines. Likewise, CCS remains a niche technology under emissions stabilization.

Figure 16: Range of GDP increase from CCS under different assumptions about declines in CCS costs

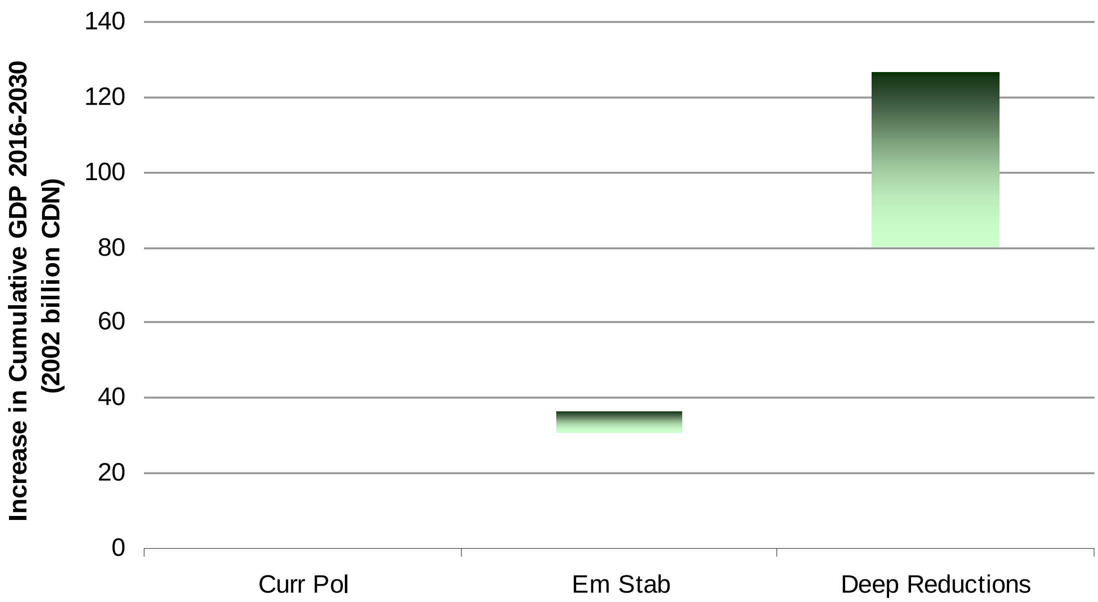


Delay in CCS implementation

In the base analysis, CCS was assumed to become available after 2016; however CCS implementation could occur later. Figure 17 shows the range of increases of Alberta's cumulative gross domestic product under different implementations dates. The direction of the results is relatively insensitive to a later implementation date for CCS – CCS continues to provide a benefit regardless of the implementation date. However the benefit is less pronounced under deep reductions if CCS is implemented later. CCS is an integral part of achieving deep reductions. The later date for CCS implementation increases the compliance costs with the policy between 2016 and 2021 because CCS is not available. But a later implementation date also slows costs from declining and costs for CCS are higher in 2030. This results in lower economic activity when CCS is implemented at a later date.

Economic activity is less sensitive to the implementation date for CCS under current policies and emissions stabilization. Under current policies CCS is only adopted after about 2021 anyway; while under emissions stabilization CCS is adopted after 2019. So a later implementation date only slightly delays when CCS would be adopted.

Figure 17: Range of GDP increase from CCS under implementation dates for CCS



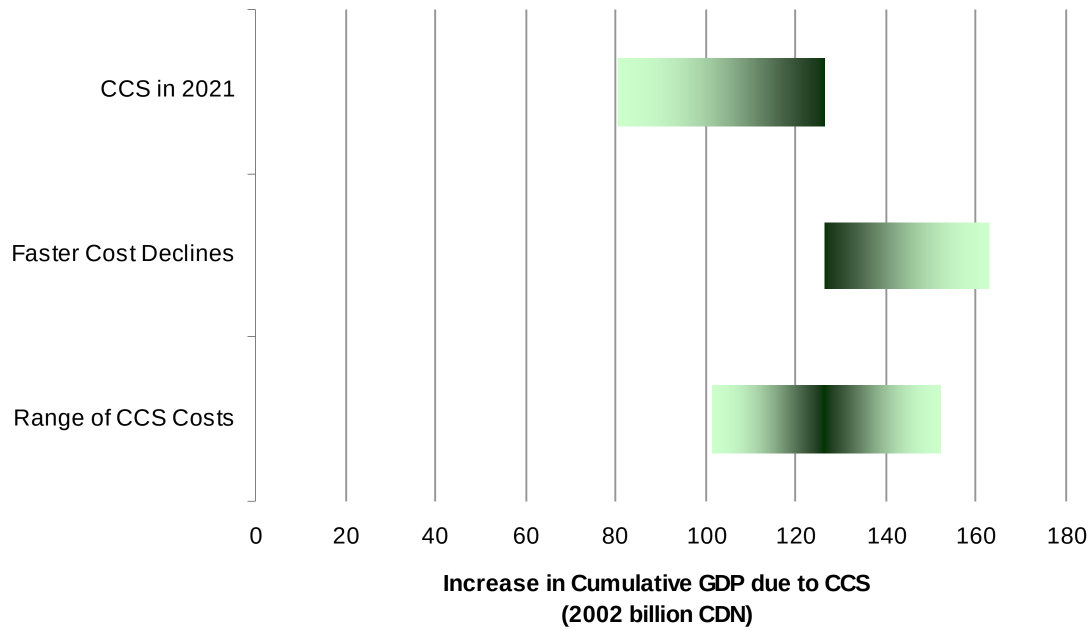
The relative importance of uncertain variables

The sensitivity analysis examined the impact of three uncertain parameters: 1) costs for CCS, 2) the decline in CCS costs over time and 3) the implementation date for CCS. CCS was shown to have positive economic benefits under each assumption, but the degree of benefits varies. To compare the relative importance of different assumptions about CCS, Figure 18 shows a tornado diagram for the cumulative economic benefits due to CCS for the deep reductions policy. Tornado diagrams show the relative sensitivity of the results to alternative assumptions – assumptions to which the results are least sensitive are displayed at the bottom (i.e., most narrow) part of the tornado diagram while assumptions to which the results are most sensitive are displayed at the top. Tornado diagrams are useful to show where government and industry should place their efforts to increase certainty around assumptions – if the results are more sensitive to a particular assumption it is more worthwhile to improve certainty around that assumption. The deep reductions scenario was selected as the best example because it showed the widest range of economic benefits under each of the assumptions.

Under the deep reductions policy, the base assumptions suggest the availability of CCS would add $126 billion to Alberta's economy between 2016 and 2030 (the darkest part of the bars in Figure 18). Although the range of economic benefits from the range of CCS costs is the widest ($51 billion), benefits are a maximum of $26 billion different from the base assumptions. Faster declines in the costs for CCS would yield $36 billion in additional provincial income between 2016 and 2030; while a later implementation date would yield $46 billion less in cumulative gross domestic product.

The difference from the base values is largest for the later implementation date because CCS is an integral part of achieving deep reductions in emissions. Therefore the later date prevents industry from accessing a relatively low-cost means of reducing emissions in the near-term.

Figure 18: Tornado diagram for deep reductions



Other Benefits of CCS

As part of the goals for this research, the steering committee was looking to understand the benefits of CCS to Alberta's knowledge economy, which can generally be thought of as the human capital and expertise developed around CCS. Impacts on the knowledge sector could include:

- Development of expertise related to CCS and its deployment, and opportunities to export this expertise to other jurisdictions;
- Development of knowledge, experience, and intellectual capital that leads to decreases in the cost of CCS technologies; and
- Attraction of researchers to knowledge-sector institutions such as universities and research institutes, leading to an increase in economic output from the knowledge sector

The first impact (identification and estimation of export opportunities) was part of Jacobs' analysis in the first phase of this study. Jacobs estimated the size of the global CCS market to be between \$2.1 and \$4.2 trillion cumulatively between 2015 and 2035, depending upon the aggressiveness of global GHG reduction policies. Many countries are competing for this market, including the United States, United Kingdom, Australia, Norway, and Netherlands. Jacobs found that Alberta's firms are not likely to attain a significant portion of this international market, due to the global nature of many technical services providers, Alberta's high labour rates, a dissimilar technical focus compared to other regions that are mostly focused on coal applications of CCS, and pre-existing CCS technology clusters in other areas. Jacobs concluded that Alberta's competitive advantages and CCS export opportunities are likely to be specific to oil sands applications, for which there is a limited market.

As this project has progressed however, there have been several developments internationally related to CCS. Some governments, such as Australia, have reduced their funding for CCS. Additionally, there have been a number of CCS project deferrals and cancellations, including most recently the announcement that American Electric Power would not proceed with the Mountaineer project, which would have installed a commercial-scale CCS system at a coal-fired power plant, in cooperation with the U.S. Department of Energy. Over the same period, CCS support and progress remained strong in Alberta, and the province has just signed a contribution agreement with Swan Hills Synfuels to provide funding for their in-situ coal gasification plant, which may produce intellectual capital and experience that are of interest to nations focused on coal applications of CCS. If these trends continue, Alberta may find that its competitiveness in the global CCS market has improved, and that CCS-related export opportunities may be greater than predicted.

The second impact (the decrease in CCS costs that is likely to result from the knowledge and experience gained from CCS deployment) was analyzed by MKJA through a literature review and interviews with Steering Committee members. The results are summarized and discussed in Appendix 2. MKJA used this research to select the learning rate (11% for capital costs and 22% for operating and maintenance costs) and the cumulative decrease in CCS costs over time (50% by 2030 under aggressive deployment of CCS) that were used when modelling the scenarios. The impact of a cumulative decrease in CCS costs of 50% by 2020 was investigated in the sensitivity analysis, representing the case where a technological breakthrough occurs and is commercialised in the near future.

The third impact (growth in the knowledge sector) is discussed in this section. Additionally, discussions with the Steering Committee over the course of this project revealed that there was a strong interest in the potential benefits that CCS could have on social and reputational issues, such as:

- Shareholder activism, and its potential implications for the cost and availability of capital for oil sands investments
- The oil sands sector's 'social license to operate'

The scale of the potential economic impact associated with many of the knowledge sector and general reputational benefits of CCS are difficult to estimate quantitatively, and are discussed qualitatively. However, the potential impacts of a higher cost of capital for oil sands operators as a result of shareholder activism or other 'social license to operate' concerns were possible to analyze quantitatively, and the results were presented and discussed in the previous section.

Social Pressures Related to the Oil Sands

Over the past several years, Alberta has been the target of a series of increasingly active and well-funded campaigns aimed at slowing or halting oil sands development. Generally orchestrated by environmental organizations, these campaigns have attracted significant media attention and are designed to foster a negative public view of the oil sands (and in some cases of Alberta or Canada as a whole). In addition to advertising campaigns designed to raise public awareness of issues related to oil sands development, many campaigns specifically aim to create financial or political pressure on the Alberta government, industry, and the federal government to withdraw their support for the oil sands industry, through actions such as:

- Urging American and British travelers not to visit Alberta in protest over oil sands development
- Calling on the UK government to ban the import of Canadian oil
- Pressuring financial institutions in Canada and abroad to cease providing funds for oil sands projects
- Encouraging major corporations to publicly boycott petroleum products from the oil sands
- Introducing shareholder resolutions calling for the justification of oil sands investments

- Creating political pressure on oil sands regulators by reaching out to voters in their home ridings or constituencies

It is difficult to estimate the economic impact of these campaigns. The impact of any one campaign may be insignificant economically, but the cumulative effect on Alberta's international reputation could be much greater, with implications for international relations, attraction of business and investment, tourism, and access to labour. By taking a leading role in the development and deployment of CCS, Alberta is showing world leaders and citizens that the province takes climate change seriously and is actively investing in solutions. However, it is by no means guaranteed that the development and deployment of CCS will satisfy the concerns of those who are opposed to development of the oil sands; many of the organizations involved in the international campaign against the oil sands are opposed to CCS as well. It is quite possible though that Alberta's commitment to CCS could help it to counter and dilute the message that the public is receiving from anti-oil sands campaigners.

Shareholder Activism and the Cost of Capital

The past two years have seen the emergence of stakeholder activism aimed at companies involved in oil sands development. Shell, BP, ExxonMobil, ConocoPhillips and Total have all been the subject of special resolutions put forward by ethical investment-oriented institutional investors, which have called on companies to fully disclose and justify their involvement in Alberta's oil sands sector. While none of the special resolutions have passed, the activist shareholders have achieved their goal of raising awareness and starting discussion, and have taken credit for Shell's decisions to disclose more information about its oil sands projects and slow down future oil sands development. Analysts expect that both the number and impact of shareholder activism campaigns targeting the oil sands will increase in the future.[29]

There is no published research on the impacts of shareholder activism on the current or future cost of capital in the oil sands sector, and so it is very difficult to predict the impact that shareholder activism could have on oil sands production and GDP. The closest proxy is the literature assessing the so-called "sin industries" (tobacco, alcohol, gaming, biotech alterations, weapons, and adult entertainment) that have been targeted or avoided by activist investors, and how their value and cost of capital have been affected. Analysts have found that there is significantly lower holding of "sin stocks" by those institutional investors whose investment practices and portfolios are

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[29] The Ecologist, February 26, 2010, "BP and Shell Face New Shareholder Revolt over Tar Sands". http://www.theecologist.org/News/news_round_up/422839/bp_and_shell_face_new_shareholder_revolt_over_tar_sands.html; Melnitzer, J., April 23, 2010, "Oil Sands Shareholders Demand Climate Change Disclosure", *The National Post*. http://network.nationalpost.com/NP/blogs/legalpost/archive/2010/04/23/oil-sands-shareholders-demand-climate-change-disclosure.aspx; Tait, C., February 8, 2010, "Shareholders Put Oil-Sands Risks on Agenda", *The Financial Post (Montreal Gazette)*.

public knowledge, and who are susceptible to public opinion (universities, pension funds, etc.). The result of the avoidance of these stocks by institutional investors is that their value (measured by price to book and price to earnings ratios) is 15-20% lower than it would otherwise be. This directly affects these companies' cost of capital when issuing new equity, and while not analyzed, it is reasonable to expect that institutional investors would also avoid these corporations' bonds, leading to a similar increase in the cost of capital from the bond market.[30]

There are clearly many issues involved in applying this research to the potential impact of CCS on ameliorating shareholder activism in the oil sands sector. The research was conducted on stock valuations, which have a less direct impact on the cost of capital. There are also many factors at play in the sectors analyzed beyond the increased risk associated with their lower social acceptability. Additionally, few investors would currently categorize the oil sands as a "sin industry", and the extent to which shareholder activism and international campaigns against the oil sands will change this perception is uncertain. Finally, it is unclear that the implementation of CCS in the oil sands would avert shareholder activism. Given all of these issues, MKJA decided to model the impact of a range of potential increases in the cost of capital to oil sands operators. Increases in the cost of capital were modeled as an implicit tax on capital, and values of 2%, 10%, and 15% were selected for evaluation, based on the literature reviewed. The results are summarized in the preceding section, but generally showed that even at 15%, an implicit tax on capital did not have a sufficient impact on oil sands producers to compel them to adopt CCS in order to avoid the cost of capital increases. This suggests that the economic impacts of shareholder activism in the oil sands are likely to be relatively insignificant compared with larger risks, such as barriers to the United States market.

Social License to Operate

Shareholder activism is an example of an activity taken to challenge the oil sands industry's "social license to operate", which is based on stakeholders' assessments of the social and environmental responsibility of oil sands developers and the strength of the province's regulations and oversight of the oil sands sector. Provincial government approval to develop an oil sands project is no longer sufficient; local communities, the broader public, and influential stakeholders are increasingly challenging the industry's social license to operate, and by doing so are placing numerous costs and obstacles in project developers' paths. Some of those obstacles were discussed above in the overview of recent campaigns against the oil sands industry. Where these challenges may have an impact on the cost of capital, the modeling results from the shareholder

[30] Hong, H. and M. Kacperczyk, 2009, "The price of sin: The effects of social norms on markets", *Journal of Financial Economics*, 93:1 15-36.; Fabozzi, F., K. Ma, and B. Oliphant, 2008, "Sin Stock Returns", *The Journal of Portfolio Management*, 35:1 82-94.

activism scenarios described above can also be considered a proxy for the potential economic impact of other concerns related to the sector's social license to operate.

The reputational impacts discussed above also have an important role to play in assessments of the oil sands sector's social license to operate. Canada's diminished global reputation due to the international campaign against Alberta's oil sands industry is believed to be the driving force behind the federal government's stated intention to step in and regulate greenhouse gas emissions from the oil sands later this year.[31] Analysts now believe that "the battle between the Alberta provincial government and the federal Government of Canada involving greenhouse gas (GHG) emissions from Alberta oil sands production could affect investments in or demands for the Canadian crude oil and related infrastructure", and that this political struggle will further increase the risks and uncertainties faced by companies investing in the oil sands.[32]

Growth in the Knowledge Sector

By taking a leading role in the development and deployment of CCS, Alberta has the opportunity to position itself as an applied science and innovation leader, which may help to attract researchers to the province and spur the development of new knowledge institutions. As a macroeconomic model, GEEM already incorporates the impact of CCS adoption on demand for engineering, construction, and other services. Economic activity related to knowledge institutions such as universities and research institutes is included in GEEM's modeling of the services sector, and when the oil and gas sector grows, the model responds by increasing demand for education services. MKJA conducted an extensive literature review in order to try to estimate the linkages between CCS deployment and knowledge sector growth, so that GEEM's treatment of economic activity related to knowledge institutions could be updated if necessary. However, little research relevant to the topic exists, and so the scale and impacts of CCS-related knowledge sector growth are difficult to estimate. Rather than introducing a potential source of error into otherwise robust modelling results by adding a variable that has a high degree of uncertainty, we discuss CCS's potential knowledge-sector related impacts qualitatively and suggest policies and actions that could spur knowledge-institution related growth and economic impacts.

The effects of CCS-related knowledge institution growth in Alberta could include revenue and economic spin-offs resulting from the attraction of foreign students and researchers to Alberta, and the development of marketable technologies and intellectual capital by these researchers. While many observers discuss the economic impact and pivotal role of universities on the development of new technologies and

[31] Riley, S., May 27, 2011, "Too Little Too Late Still Too Much for Alberta", *Ottawa Citizen*. http://www.ottawacitizen.com/business/little+late+still+much+Alberta/4847007/story.html
[32] Utzinger, T., July 19, 2011, "Alberta Oil Sands Regulatory Fight May Reach From Coast to Coast", *Thomson Reuters Accelus*. http://currents.westlawbusiness.com/Article.aspx?id=4cd6e086-a744-4dca-8620-fcb7d35339b2

industries, in their contribution to the World Bank report *Higher Education and Development*, Feldman and Stewart state that this perception that universities are engines of economic growth exaggerates what it is possible for universities to accomplish. They note that universities had a supportive, but not motivating role in the development of major American knowledge-based clusters such as Silicon Valley and Route 128, and "university involvement with emerging industries has tended to lag rather than lead their development, with entrepreneurs engaging universities".[33]

As a result, while universities offer substantial benefits to their host communities and regions, including significant economy-wide benefits stemming from the higher earnings of university graduates, their potential role as direct drivers of economic growth from CCS innovation and knowledge development (e.g. from the attraction of new researchers and students, the development of spin-off companies, and the licensing of intellectual capital) may not be as high as many assume. Little academic work is available to help quantify the scale and value of each of these impacts. Those benefits that can be quantified, such as the economic value associated with attracting foreign students, are likely to be smaller and less important than those impacts that are more difficult to measure, such as the development and transfer of knowledge that can contribute to lowering the costs of CCS (through publishing, consulting etc.), and the training of skilled workers and researchers in the field. These latter two benefits are considered dynamic impacts, and together are recognized to increase productivity and GDP.[34]

The economic impacts associated with each of the major potential benefits from CCS-related knowledge institution growth are summarized below:

Attraction of students and researchers

By showing leadership in the CCS field, Alberta is likely to attract students and researchers who see value in studying and conducting their research in a jurisdiction with a range of commercial-scale CCS projects under active development. However, the direct economic impact of the attraction of CCS-related researchers and students to Alberta is likely to be quite small compared to the other benefits of CCS that were analyzed, such as the protection of the United States export market.

Within Alberta, there is a substantial cross-over between the CCS research field and oil and gas and electricity-related research, and so to some extent new CCS researchers will actually be existing researchers who have shifted their focus. In addition, numerous programs (such as the federally funded Canada Research Chairs and Canada Excellence Research Chairs) already provide funding aimed at attracting world-class researchers in the natural resources and energy fields to Canadian universities, who are then expected

[33] Feldman, M. And I. Stewart, 2008, "Wellsprings of Modern Economic Growth: Higher Education, Innovation, and Local Economic Development", in *Higher Education and Development,* Lin, J. And B. Pleskovic *eds*, The World Bank.
[34] Martin, F., 1998, "The Economic Impact of Canadian University R&D", *Research Policy* 27 677-687.

to spur innovation and knowledge advancement, build strong international partnerships, and share their expertise with other university researchers and students. These two factors reduce the incremental economic benefits that are likely to be achieved through the attraction of new CCS researchers.

The direct economic impact of attracting international students is based on spending on tuition, accommodation, and discretionary items. In 2008, each foreign student attending Alberta's universities spent an average of $27,500, and the cumulative impact of foreign university students on Alberta's economy was over $189 million.[35] Alberta also attracts students from across Canada, and the cumulative spending of university students from outside Alberta is $800 million.[36] Only a small proportion of these students are studying in CCS-related programs though, so even with high growth rates, the total direct economic impact of attracting new students will be quite low.

However, the direct economic benefits are only one impact associated with attracting CCS-focused students and researchers to Alberta. Much more important is the potential for these students and researchers to:

a. Develop knowledge that will contribute to lowering costs and increasing productivity in the CCS sector, and
b. Become skilled workers who stay in Alberta and join the province's CCS industry, helping to ameliorate a potential future skilled worker shortage in the CCS field.

Development of new research groups and networks

Alberta's commitment to CCS development and deployment is likely to result in the development of new public and private groups dedicated to researching various aspects of CCS. However, it is very difficult to forecast how many new research groups Alberta might attract, and what contribution they will make to the province's economy. Effective development of the CCS sector will also depend upon the existence of networks that bring together researchers in academia, government, and industry, in order to facilitate joint discoveries and the diffusion of new knowledge. However, Alberta is already well positioned in this area. Carbon Management Canada (CMC) is a Network of Centres of Excellence that is funded by both the federal and Alberta governments, and brings together nearly 100 researchers from 22 Canadian universities. CMC's focus is on projects that will have a concrete impact on reducing greenhouse gas emissions (rather than purely theoretical or 'academic' work), with a substantial number of its researchers working on CCS. The development of 'highly qualified personnel' is another key goal. In order to foster additional linkages, international experts participate

[35] Roslyn Kunin & Associates, Inc., 2009, *Economic Impact of International Education in Canada*. http://globalhighered.files.wordpress.com/2009/10/rka_inted_report_eng.pdf

[36] Alberta Universities Association, 2005, *Social and Economic Impact of Alberta's Universities*. http://www.albertauniversities.org/A%20Learning%20Alberta/Social%20Economic%20Impact%20-%20AUA%20Toolkit%20Aug%2024.pdf

in the review of proposed research, and CMC is working to increase industry's involvement in its projects.

CMC is only in its second year of operation, so it is too soon to be able to estimate the economic impact of the network, but its role in CCS-related knowledge development is expected to be substantial. Additionally, Alberta Innovates is an existing government organization that is uniquely designed to break down barriers and encourage collaboration between university researchers, companies, and government. Together, the existence of CMC and Alberta Innovates mean that much has already been accomplished in this area, limiting the potential incremental impact of the creation of new CCS research groups and networks.

Direct economic value of CCS-related innovations

When universities and research groups develop CCS-related innovations, they have the opportunity to commercialize this new knowledge by patenting and licensing their intellectual capital, or creating spin-off companies. Efforts to measure the direct economic impacts of these actions in Canada are preliminary, but across Alberta's universities there have been more than 100 spin-off companies, with an estimated value of more than $1 billion. Hundreds of patents are owned by Alberta's university researchers, and the annual earnings from royalties on intellectual property are in the range of $30 million.[37] However, these figures are provincial, and include all universities and knowledge creation in all sectors. This suggests that even with the attraction of a substantial number of CCS researchers and students, and the creation and commercialization of a significant number of CCS-related innovations, the direct economic impacts are likely to be quite small compared to the other benefits of CCS that were examined in this analysis.

Innovations that reduce the costs of CCS

The creation and dissemination of knowledge that reduces the capital and operating costs of CCS is one of the greatest potential benefits associated with the expansion of Alberta's CCS-related knowledge sector. Universities perform a third of Canada's research and are likely to make a substantial contribution to CCS-related innovations, particularly with the existence of research networks like Carbon Management Canada.[38] The scale of the potentially achievable cost reductions was evaluated as part of MKJA's research on learning rates, and is summarized above and in Appendix 2. In addition, the potential impact of more rapid innovation was evaluated as part of the Sensitivity Analyses, with the results summarized in the previous section. Alberta is well situated to be the site of substantial CCS-related knowledge development due to the confluence of its strong oil and gas industry expertise, strong and consistent government support for CCS, substantial CCS-related funding, high-quality researchers and research institutions, and forthcoming commercial projects demonstrating CCS in a variety of

[37] Alberta Universities Association (2005)

[38] Morris, Claire, 2005, "Telling the Research Story". http://innovationcanada.ca/en/articles/telling-the-research-story

different applications. In order to protect and build on this competitive advantage, the next section presents a number of policies and actions that can be used to increase the economic impacts that are derived from Alberta's CCS-related knowledge sector.

Policy Recommendations

Alberta has taken substantial action to ensure that it is not just an early mover, but *the* early mover in CCS internationally. With continued commitment and policy leadership, Alberta can encourage the province to be a major center of growth for the CCS industry. The use of policies to foster domestic demand and create initial markets for CCS is critical, as these give companies the initial impetus and foothold to grow and eventually compete in global markets.[39] Alberta's carbon price, double offset credits for CCS projects, and CCS Fund all do this. Alberta will need to continue to develop and implement policies that encourage the implementation of CCS in Alberta as the industry takes root.

Rapid industrial innovation and growth is also dependent upon research and development activity, knowledge transfer, access to information, connections between all those involved in the field, and access to trained researchers and workers. Supplementary policies and actions that can support these goals include:

- Helping universities and industry to identify and overcome the roadblocks that interfere with their collaboration, which are often related to issues such as university overhead rates and project and funding timelines.
- Supporting the co-location of university researchers and industry, for example through university research parks. Carbon Management Canada researchers have identified the need for a business incubator in Alberta similar to that at Memorial University.
- Developing programs similar to the UK's Knowledge Transfer Partnerships and Knowledge Transfer Networks, which provide information and networking opportunities for researchers and industry.
- Conducting a skills audit for CCS, including an identification of the skills requirements for a successful CCS industry, the availability of workers with those skills in Alberta, and the resulting skills gaps. The skills audit should also identify market barriers to developing these skills (such as lack of secondary student knowledge about CCS opportunities and the training that they will require, and potential incompatibilities between the type of training needed by those working in industry, and that provided by knowledge institutions).
- Helping to develop the training programs required to provide the skills identified by the CCS skills audit, including post-graduate degrees in CCS, technical school training programs, and courses designed to conveniently and efficiently upgrade the skill sets of those working in industry. If the skills audit finds that the

[39] Pew Center on Global Climate Change, 2011, *Clean Energy Markets: Jobs and Opportunities.*

required skillsets are available in Alberta, but are operating at full capacity due to demand in other sectors, policies and actions designed to increase the number of students entering studies in the required fields may be required.

Alberta Innovates is in a unique position to undertake many of these actions, due to its mission, resources, expertise, and networks.

Summary and Recommendations for Future Research

Summary

This study examined six potential benefits to Alberta's economy from the adoption of CCS:

1. **Maintaining access to export markets and the markets for capital**. The United States could implement policies that restrict access of Alberta crude oil into American markets. This could be done by either imposing a ban on new pipelines carrying Alberta crude oil, or implementing a federal low-carbon fuel standard. Additionally, there is a risk that shareholder activism or other challenges to the oil sands sector's social license to operate could increase the cost of capital.

   We explored three potential pipeline scenarios, including 1) the Keystone XL pipeline and subsequent pipelines are not built, 2) Keystone XL is built but all subsequent pipelines are not built, and 3) Alberta avoids a pipeline ban by adopting CCS. Pipeline bans reduce the price for Alberta crude oil. Under both pipeline ban scenarios, the price on a barrel of raw bitumen is between $23 and $24 lower in 2030 (2002$) than if Alberta can avoid the pipeline ban by adopting CCS. However, the adoption of CCS by Alberta's in-situ bitumen producers results in additional costs of $6.6 per barrel in 2030. Because the decline in price from the pipeline bans exceeds the costs associated with adopting CCS, there is a substantial economic benefit from the adoption of CCS to avoid a pipeline ban. Overall, cumulative gross domestic product from 2016 to 2030 is between 2.2% and 3.0% higher if Alberta can avoid a pipeline ban by adopting CCS.

   A low-carbon fuel standard also reduces the price on Alberta crude oil. The policy implicitly imposes a tax on fuels with emissions intensities above the standard and acts like a subsidy for fuels with intensities below the standard. As transportation fuels produced from the oil sands have high emissions intensities in comparison to other forms of transportation fuels (e.g., light medium crude oil or cellulosic ethanol), the LCFS acts as a tax on products from the oil sands. However, oil sands producers can reduce their exposure to the implicit tax by reducing their greenhouse gas intensity by adopting CCS. The price for a barrel of raw bitumen is $18 greater in 2030 if oil sand producers adopt CCS, while the costs of adopting CCS for in-situ bitumen extraction are only $6.6 per barrel, resulting in substantial positive economic benefits from the availability of CCS. Overall, the availability of CCS to Alberta's oil sands producers as an option for mitigating the impact of an American low-carbon fuel standard results in a 4.1% increase in Alberta's cumulative gross domestic product between 2016 and 2030.

There are also concerns that shareholder activism could increase the cost of capital or lead to short-term capital shortages for oil sands producers. MKJA evaluated the impact of a range of potential cost of capital increases on Alberta's gross domestic product and on oil sands production. However, even under cost of capital increases as high as 15%, industry does not have an incentive to adopt CCS in order to avoid the increased cost of capital, as the costs are lower than those associated with adopting CCS. As a result, cost of capital increases due to shareholder activism or other challenges to the industry's social license to operate are not likely to have a substantial impact on marginal oil sands producers.

2. **Impact on value added industries**. The benefit of CCS on value-added industries depends on the level of aggressiveness of policies to reduce greenhouse gas emissions. Under current policies, CCS provides a niche benefit by enabling the development of enhanced oil recovery. This allows for more aggressive growth in the conventional oil and government sectors, with the latter benefiting from higher royalties. Under current policies, cumulative gross domestic product is 0.4% greater when CCS is available.

   As policies to reduce greenhouse gas emissions become more aggressive, industry can reduce exposure to the policies by adopting CCS. For example, if a policy imposes a cost of $150 per tonne CO_2e and the cost of adopting CCS is $100 per tonne, CCS would provide a benefit to industry. Again, the oil and gas and government sectors are the most significant beneficiaries from CCS availability. If Canada stabilizes its emissions by 2030, the availability of CCS leads to a 1.0% improvement in the Alberta's cumulative income between 2016 and 2030. If Canada achieves its targets for greenhouse gas emissions – a 17% reduction from 2005 levels by 2020 and a 65% reduction by 2050 – CCS availability adds 3.7% to provincial income between 2016 and 2030.

3. **Use of CO_2 captured from CCS for enhanced oil recovery**. Enhanced oil recovery (EOR) provides a benefit to Alberta's economy on two fronts. First, carbon dioxide sales benefit facilities that adopt CCS by offsetting a portion of the costs from installing and operating CCS equipment. In policies with rapid deployment of CCS, this benefit is short-lived as the supply of CO_2 quickly exceeds the maximum demand, and the price for CO_2 will decline to zero. However, CCS costs are likely to be highest during the initial phase of CCS implementation, so CO_2 sales for enhanced oil recovery act as a bridge to lower CCS costs.

   The second benefit from enhanced oil recovery is related to greater conventional oil production. This increases economic activity in oil and gas production and maintains stronger oil and gas royalties to government than in the absence of enhanced oil recovery. Between 2016 and 2030, cumulative royalties from enhanced oil recovery are estimated at between $7 and $15 billion (2002$).

4. **Enabling the continued use of coal**. Under policies to reduce greenhouse gas emissions, electricity generators have three main abatement options: 1) adopt CCS at coal- and/or natural-gas fired power plants; 2) switch from high emissions intensity fuels (i.e., coal) to lower intensity fuels (i.e., renewable resources or natural gas); and 3) increase imports from regions with lower emissions intensity (i.e., hydroelectricity from British Columbia). CCS availability would reduce the emissions intensity from coal-fired electricity generation and help maintain lower electricity prices. Under policy scenarios that achieve emissions stabilization or achieve Canada's greenhouse gas emission reduction targets, the availability of CCS leads to electricity prices that are $10 and $50 per MWh (2002$) lower in 2030 respectively.
5. **Helping to avert social pressures related to the oil sands.** Over the past several years, Alberta has been the target of a series of increasingly active and well-funded campaigns aimed at slowing or halting oil sands development. It is difficult to estimate the economic results of these campaigns. While the impact of any one campaign may be insignificant economically, the cumulative effect on Alberta's international reputation could be much greater, with implications for international relations, attraction of business and investment, tourism, access to labour, and federal/provincial relations. By taking a leading role in the development and deployment of CCS, Alberta is showing world leaders and citizens that the province takes climate change seriously and is actively investing in solutions, which may help the province to counter and dilute the message that the public is receiving from anti-oil sands campaigners.
6. **Growth in the knowledge sector**. Alberta's investments in and commitment to CCS position the province as an applied science and innovation leader, which may help to attract researchers to Alberta and spur the development of new knowledge institutions. The economic effects of this knowledge sector growth could include revenue and economic spin-offs resulting from the attraction of foreign students and researchers to Alberta, the development of marketable technologies and intellectual capital by these researchers, the development of knowledge that will contribute to lowering the costs of CCS deployment in Alberta, and the training of skilled researchers and workers who may help to ameliorate potential future skilled worker shortages in the CCS field. Our research suggests that the economic impacts related to the first two economic impacts (the attraction of students and researchers to Alberta and the commercialization of intellectual capital) will be quite low compared to other benefits of CCS that were analyzed, such as access to the United States market. The latter two benefits (the development of knowledge that reduces the cost of CCS deployment and the training of skilled researchers and workers for the CCS industry) are dynamic and their economic impacts are much more difficult to estimate. However, these benefits are likely to have a significant positive impact on Alberta's economy.

Recommendations for Future Research

There are a number of ways in which the analyses conducted for this project can be extended in the future if Alberta Innovates - Energy and Environment Solutions, Alberta Energy and Alberta Environment are interested. These could include:

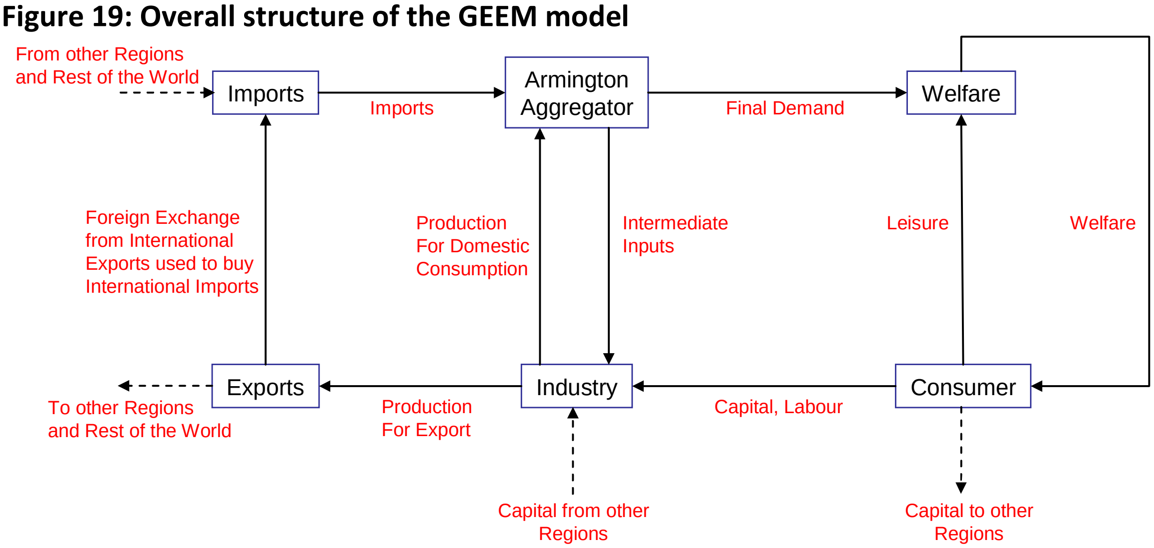
1. Conducting a comparative economic analysis of the different policies and actions available to Alberta to promote CCS development and deployment, such as direct investment, tax and royalty rate adjustments, low or no interest loans to industry, and the construction of CCS-related infrastructure. An extension of this research would be an investigation of the potential benefits associated with the Alberta government funding the capital costs of CCS implementation in the oil sands. Since adoption of CCS by oil sands operators results in a decline in the royalties they pay to the province, it is possible that the cost to Alberta of funding the capital costs of CCS deployment could be partly or completely offset by the resulting increase in oil sands product production and royalty revenues.
2. In the analysis of policies to limit access to export markets, we assumed that Alberta access to all crude oil export markets would be compromised if the oil sands do not adopt CCS. We could explore several different scenarios for pipeline bans, such as the implications of Enbridge's Northern Gateway pipeline being built if the Keystone XL pipeline is not built.
3. Modelling the impact of different allocations of Alberta's Climate Change and Emissions Management Fund revenue on CCS costs and deployment, provincial GDP, and other metrics. In this analysis, contributions to the technology fund are invested in renewable electricity generation. However, future analyses could investigate the impacts of allocating technology fund revenue to CCS, other technologies, or various combinations of these options.
4. Exploring the potential impact of policies specifically designed to ameliorate the negative impacts that CCS adoption has on certain sectors.
5. Adding information about the potential for shale gas development in Alberta to GEEM, and modeling the impacts of various policy scenarios on shale gas production.
6. Explicitly adding greenhouse gas policies implemented in other provinces and states to the analysis. This could include British Columbia's carbon tax, Quebec's carbon levy and the potential Western Climate Initiative cap-and-trade system. These policies were excluded from the Current Policies scenario for simplicity, but could affect North American demand for fossil energy.
7. Modelling the potential economic impact of the federal government's stated intention to regulate greenhouse gas emissions from the oil sands sector through the introduction of performance rules applicable initially to new facilities, and eventually to all facilities.

If any of these analyses are of interest, we would be pleased to provide additional methodological detail and an estimate of the cost to conduct the analysis.

Appendix 1: The GEEM Model

To complete the analysis, MKJA employed a computable general equilibrium (CGE) model called GEEM. This model is essentially a sophisticated input-output economic model that balances supply and demand for commodities and services in all markets by solving for prices. Our current GEEM model represents Alberta, the rest of Canada and the United States as separate regions, and each of these regions interact through trade of commodities and services. Capital is assumed to be mobile among regions within North America, while labour is assumed to be mobile within provinces or states. In the model, a representative household in each region is the owner of primary factors (labour, capital and natural resources) which they rent to producers who combine them with intermediate inputs to create commodities. Commodities can be sold to other producers (as intermediate inputs), to final consumers, or to other regions and the rest of the world as exports. Commodities can also be imported from other regions or the rest of the world. The key economic flows in GEEM are captured schematically in Figure 19.

Figure 19: Overall structure of the GEEM model



The current version of GEEM is dynamic and solves in annual increments from 2002 to 2030. One of the benefits of using a dynamic model is it can simulate policies that change over time as well as producing results for multiple years. For example, it can simulate carbon taxes that rise over time, or regulatory policies (e.g., requirements for carbon capture and storage) implemented in a certain year. Furthermore, the model simulates capital accumulation over time, and adjusts savings (and therefore investment) based on the rate of return to capital.

The data underlying the model is derived primarily from the Statistics Canada System of National Accounts. We use the S-Level Input, Output, and Final Demand tables to populate the model, and aggregate these somewhat to focus on sectors of primary interest. One of the challenges with the S-Level data is its lack of disaggregation for energy and emissions intensive sectors. We disaggregate these sectors using the M- and L-Level data from Statistics Canada, Statistics Canada's Report on Energy Supply and Demand, CAPP's production data for oil and gas production, MKJA's CIMS energy economy model, among other sources.

The following sections describe our representation of industry, consumers and trade between provinces and countries.

Industry

The GEEM model represents 33 industries in Alberta and North America (see Table 27). The table also shows the data from Statistics Canada's input-output tables on which the sectors are based.

Table 27: Industries in GEEM

GEEM Code	*GEEM Sector Description*	*Data Available for AB at the S-Level*
PEXT	Crop and animal production	Crop and animal production
	Forestry and logging	Forestry and logging
	Fishing, hunting and trapping	Fishing, hunting and trapping
	Support activities for agriculture and forestry	Support activities for agriculture and forestry
OSMIN	Oil sands mining	Mining and oil and gas extraction
OSIS	Oil sands in-situ	
BITUP	Bitumen upgrading	
OCLM	Oil light medium	
OCHY	Oil heavy	
CNGAS	Conventional natural gas extraction	
UNGLG	Unconventional natural gas extraction with low formation carbon dioxide	
UNGHG	Unconventional natural gas extraction with high formation carbon dioxide	
COALMIN	Mineral mining	
MINING	Coal mining	
OGSER	Support activities for mining and oil and gas extraction	
CELEC	Conventional electric power generation	Utilities
RELEC	Hydroelectric and other renewable electric power generation	
PAPER	Paper manufacturing	Manufacturing
REFINE	Petroleum and coal products manufacturing	

GEEM Code	*GEEM Sector Description*	*Data Available for AB at the S-Level*
CHEM	Chemical manufacturing	
BIOFUEL	Biofuel manufacturing	
CEMMAN	Cement manufacturing	
LIMMAN	Lime manufacturing	
ONMMAN	Other non-metallic mineral product manufacturing	
IRONST	Iron and steel manufacturing	
ALMAN	Aluminum manufacturing	
OPMMAN	Other primary metal manufacturing	
OMAN	Miscellaneous manufacturing	
TRANSIT	Transit and ground passenger transportation	Transportation and warehousing
TRANS	Other Transportation	
TRMARGIN	Transportation margins	Transportation margins
WRTD	Wholesale trade	Wholesale trade
	Retail trade	Retail trade
SERV	Natural gas distribution, water and other systems	Utilities
	Construction	Construction
	Information and cultural industries	Information and cultural industries
	Finance, insurance, real estate and rental and leasing	Finance, insurance, real estate and rental and leasing
	Professional, scientific and technical services	Professional, scientific and technical services
	Administrative and support, waste management and remediation services	Administrative and support, waste management and remediation services
	Educational services	Educational services
	Health care and social assistance	Health care and social assistance
	Arts, entertainment and recreation	Arts, entertainment and recreation
	Accommodation and food services	Accommodation and food services
	Other services (except public administration)	Other services (except public administration)
	Operating, office, cafeteria, and labouratory supplies	Operating, office, cafeteria, and labouratory supplies
	Travel and entertainment, advertising and promotion	Travel and entertainment, advertising and promotion
	Non-profit institutions serving households	Non-profit institutions serving households
GOVT	Government sector	Government sector

All industrial sectors in the GEEM model are represented by constant elasticity of substitution (CES) functions, which represent the technologies industry can use to produce goods and services. Central to this function are the elasticity of substitution parameters which represent how easily a sector can substitute between different inputs while maintaining a given level of production. For example, the model simulates a tradeoff between energy consumption and value added (i.e., capital and labour) through the elasticity parameter labelled σ_{VAE} in Figure 20. A low value for σ_{VAE} indicates that the value added bundle is not very substitutable for energy; and the energy intensity of the sector is largely unaffected by new economic conditions or policies. A high value for σ_{VAE} indicates greater substitution possibilities; and economic conditions or policies that raise the price for energy relative to the price for the value-added bundle induce improvements in energy efficiency.

To model resource extraction sectors, we introduce the concept of "resource rent", which is profit earned by resource sectors that exceeds a normal rate of return on investment. Resource extraction sectors earn extra profits (some of which is collected by government in the form of royalties) because the resource they extract is scarce and resource plays have different costs of extraction. In other words, unlike manufactured commodities there is a finite amount resource to extract, such that buyers pay a premium that reflects the scarcity of the commodity. In addition, resource plays differ in their costs of extraction (quality), such that owners of easy to extract (high quality) resources earn additional profits relative to owners of resources that are more difficult to extract. For example, oil extraction from a conventional well would yield greater resource rent per unit of oil production than oil sands mining and upgrading (which has higher costs of extraction).

We use the concept of resource rent to characterize the supply curve for resources. As illustrated in Figure 20, we simulate the ability of a resource sector to substitute between the amount of a fixed resource and other inputs into production, which is represented by the elasticity value σ_{RR}. If the price for the resource increases, the value of resource rent (extra profits) for a given level of production increases. Assuming the price for other inputs into production stays constant, the model will simulate an increase in production by shifting away from the fixed resource towards greater inputs. This reflects industry moving towards more marginal resources. In an alternative scenario where the costs of extraction increase (due to the adoption of carbon capture and storage for example), the cost of inputs becomes more costly in comparison to the resource and the model simulates that the marginal resources will not be developed.

The value of all elasticity values used to parameterize the model are illustrated in Table 28. The elasticity values for σ_{RR} are calibrated to ensure the long-run supply elasticity for natural resources sector (e.g., oil sand extraction or electric generation from renewable resources) is one. This means that a one percent increase in price leads to a one percent increase in production, all else equal.

Figure 20: Structure of industrial sector in GEEM

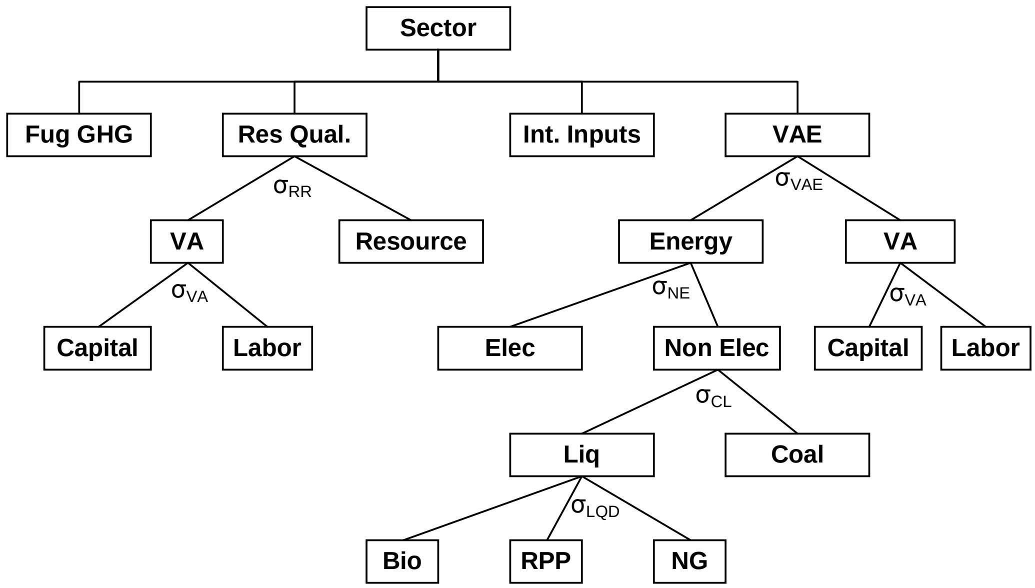


Table 28: Elasticities of substitution by sector

	σ_{RR}	σ_{VAE}	σ_{VA}	σ_{NE}	σ_{CL}	σ_{LQD}
Conventional Oil/ Gas Production	0.25	0.45	1	0.5	1	1
Other Resource Sector	3.2					
Rest of the Economy	0					

Source: Paltsev, 2005

The GEEM model includes "alternative" methods of producing goods and services from sectors with specific abatement technologies (e.g., carbon capture and storage (CCS) and enhanced oil recovery (EOR)). These technologies are typically unprofitable in the absence of a policy but become active under certain economic or policy conditions (e.g., carbon pricing or high prices for oil that warrant the adoption of EOR). Figure 21 illustrates an example of how CCS is simulated for abate emissions from coal combustion (e.g., a coal-fired electricity plant). To achieve the same level of service from coal as without CCS, the CCS technology requires 1) additional fuel consumption to reflect the energy required to operate CCS equipment ("COAL + EP" in Figure 21), 2) capital to build the CCS plant and labour to operate it ("VA"), and 3) a stream of emissions that are captured from the plan ("CCS"). The captured emissions can either be stored or transported to an EOR site at a premium. Table 29 shows the key sectors and processes in which carbon capture and storage is available. Costs were obtained from Jacobs Consulting.

Figure 21: Representation of carbon capture and storage to capture emissions from coal combustion

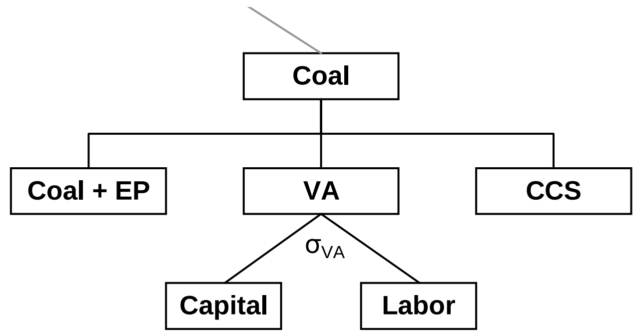


Table 29: Sector and processes that include a CCS option

	Base Cost used by MKJA (2002 CDN / tonne CO_2e avoided)	*GHG Intensity of Industry*		*Notes*
		kg CO_2e/Unit	*Unit*	
Bitumen upgrading				
Without CCS		53	kg CO_2e per barrel of synthetic crude oil	Baseline technology
Tranche 1: Hydrogen production	$83	37		Cost is based on Jacobs estimate for a SMR plant
Tranche 2: Large process heaters	$111	22		Based on Jacobs estimate for in-situ bitumen extraction
Tranche 3: Small process heaters	$204	8		Cost is based on Jacobs estimate for small process heaters
In-situ bitumen extraction				
Without CCS		78	kg CO_2e per barrel of bitumen	Baseline technology
Tranche 1: Large process heaters	$111	16		Based on Jacobs estimate for in-situ bitumen extraction
Mined bitumen extraction				
Without CCS		41	kg CO_2e per barrel of bitumen	Baseline technology
Tranche 1: Large process heaters	$111	27		Based on Jacobs estimate for in-situ bitumen extraction
Tranche 2: Small process heaters	$204	20		Cost is based on Jacobs estimate for small process heaters
Natural Gas Production				
Without CCS		6.3	kg CO_2e per thousand cubic foot (Mcf)	Baseline technology
Tranche 1: Capture of formation carbon dioxide	$83	4.5		Cost is based on Jacobs estimate for a SMR plant
Tranche 2: Capture of combustion emissions	$111	1.6		Based on Jacobs estimate for in-situ bitumen extraction
Fossil fuel-fired electricity generation				
Without CCS		943	kg	Baseline technology

	Base Cost used by MKJA (2002 CDN / tonne CO_2e avoided)	GHG Intensity of Industry		Notes
		kg CO_2e/Unit	Unit	
Tranche 1: Coal-fired electric generation	$85	210	CO_2e/MWh fossil fuel generation	Cost is based on Jacobs estimate for coal-fired generation
Tranche 2: Natural gas-fired electric generation	$102	122		Cost is based on Jacobs estimate for natural gas-fired generation
Petroleum Refining (Light/medium and synthetic oil)				
Without CCS		202	kg CO_2e per m^3 Refined Petroleum Products	Baseline technology
Tranche 1: Large process heaters	$111	154		Based on Jacobs estimate for in-situ bitumen extraction
Tranche 2: Small process heaters	$204	28		Cost is based on Jacobs estimate for small process heaters
Petroleum Refining (Heavy oil)				
Without CCS		302	kg CO_2e per m^3 Refined Petroleum Products	Baseline technology
Tranche 1: Hydrogen production	$83	280		Cost is based on Jacobs estimate for a SMR plant
Tranche 2: Large process heaters	$111	230		Based on Jacobs estimate for in-situ bitumen extraction
Tranche 3: Small process heaters	$204	42		Cost is based on Jacobs estimate for small process heaters
Cement, Lime and Iron and Steel Manufacturing				
Without CCS		100	Index - without CCS = 100	
Tranche 1: Small process heaters	$204	13		Cost is based on Jacobs estimate for small process heaters

In the GEEM model, all industries maximize profits (i.e., revenue minus costs of production) subject to technology constraints through Lagrangian optimization.

Consumers

GEEM uses a representative agent framework, where all households are represented by a single representative agent. In this framework, the representative agent maximizes his/her welfare, where welfare is a function of consumption of various commodities, savings (i.e., future consumption) and leisure (see Figure 22 for the tree structure and Table 30 for the associated elasticity values). Note that the trees representing space heating, appliances and other goods is similar to the tree representing transportation, and therefore are not shown in. Most of the elasticity values have been econometrically estimated from MKJA's CIMS energy-economy model, while the values representing the substitutability between an end-use and other goods (σ_{TST}) are from Paltsev (2005).

Figure 22: Structure of household welfare

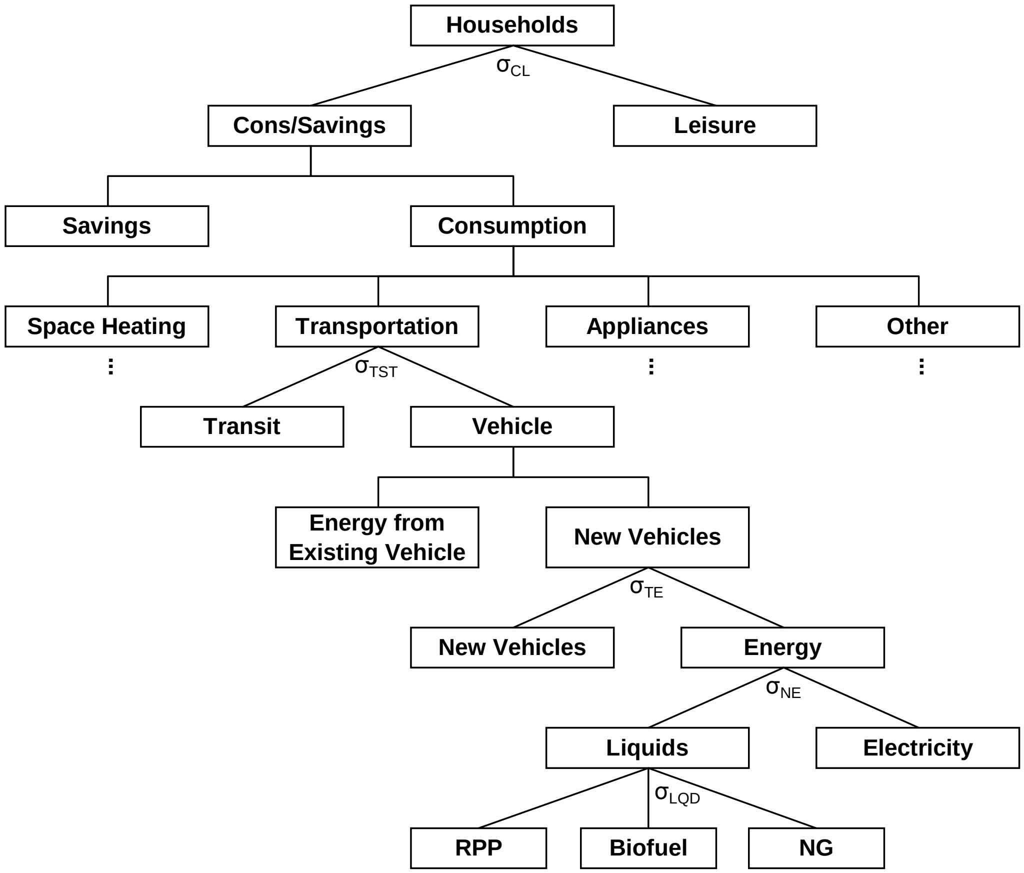


Table 30: Elasticities of substitution for households

<table>
<tr><th></th><th>σ_{CL}</th><th>σ_{TST}</th><th>σ_{TE}</th><th>σ_{NE}</th><th>σ_{LQD}</th></tr>
<tr><td>Space Heating</td><td rowspan="4">0.6</td><td>0</td><td>0.25</td><td>4.0</td><td>0.4</td></tr>
<tr><td>Transportation</td><td>0.2</td><td>0.2</td><td>5</td><td>2</td></tr>
<tr><td>Appliances</td><td>0</td><td>1</td><td>0</td><td>0</td></tr>
<tr><td>Other Goods</td><td>0.25</td><td>0</td><td>0</td><td>0</td></tr>
</table>

Source: CIMS, 2009 and Paltsev, 2005

The representative agent in GEEM maximizes his/her welfare subject to available income through Lagrangian optimization.

Trade

The substitutability between domestically produced and imported goods are represented by an armington formulation (see Figure for the structure of imports and Table 31 for the corresponding elasticity values). An elasticity of infinity indicates that a commodity is homogeneous and Alberta is price taker. This is important to represent crude oil which is priced in international markets and natural gas which is priced in North American markets.

Figure 4: Structure of imports

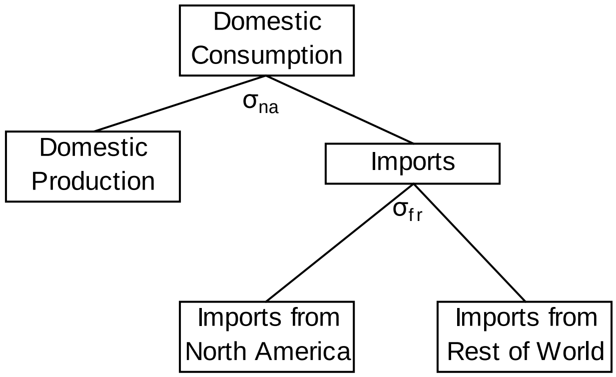


Table 31: Armington elasticities

	σ_{na}	σ_{fr}
Crude Oil	∞	∞
Natural Gas	∞	4.0
Electricity	2.5	2.5
Refined Petroleum Products	4.0	4.0
Other Goods	2.5	2.5

Source: Bohringer and Rutherford (2002)

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Appendix 2: The Impact of Technology Learning on CCS Costs

In order to model the impacts of CCS deployment on Alberta's economy through 2030, we need to account for the fact that the capital costs of CCS are likely to decline over time as the technology is deployed at scale. Knowledge and experience derived from applying CCS in a variety of different applications and environments, continued research and development, reductions in the costs of individual technological components, improved integration of CCS components, and economies of scale are all likely to lead to decreasing costs. In Phase 1, Jacobs developed cost estimates for deploying CCS in different applications in Alberta. However, these estimates reflected current costs for each application. In order to incorporate the benefits from experience and scale in MKJA's macroeconomic modeling, a method was needed to adjust Jacobs' point in time cost estimates based on accumulated experience with CCS deployment.

However, estimating how the costs of CCS will decline over time is a highly speculative exercise. Experience with the rapid deployment of technologies believed to be analogous to CCS, such as flue gas desulfurisation (FGD) in response to the introduction of stricter SO_2 emission limits for power plants in the United States, can provide some sense of how costs may decline over time. This has been one of the main methods used by researchers to estimate CCS experience curves. However, the extent to which experience with other technologies will be representative of experience with deploying CCS is uncertain. CCS is not just one technology, but a suite of potential technologies and applications, and knowledge is not necessarily transferable between them. It is possible that none of these technologies may be subject to the concentrated research and deployment effort that FGD experienced. Despite this, trying to estimate different experience curves for each CCS technology is likely to add accuracy to the modeling effort, as it would represent an attempt to increase the granularity of an estimate that is already highly uncertain. A further issue is identifying where exactly CCS is on the experience curve. Many researchers believe that costs for commercial-scale CCS projects will rise before they start falling, due to factors such as:

- Shortfalls in the performance and reliability of early system designs,
- Problems with the integration of components that have not been proven for a particular application or scale,
- An excessively fast deployment that does not allow for new units to incorporate learning, and/or
- Rising regulatory compliance, monitoring, and technology costs in order to satisfy public concerns about safety.

If CCS is still on the increasing part of the cost curve, we need to determine if and how to account for this in GEEM.

It is also unlikely that costs will decrease linearly and gradually over time. Instead, step-change improvements to CCS technologies are likely to occur, leading to substantial reductions in costs. Researchers can try to estimate how CCS costs will change in the future by looking at the current state of research and development efforts, technologies in the pipeline and undergoing testing, and technical and engineering limits to process improvements. However, it is nearly impossible to estimate when step-change technological breakthroughs will occur, and their magnitude.

It is clearly a challenge to develop a cost reduction curve that reflects these dynamics and uncertainties. As a macroeconomic model, GEEM is designed as a representation of the Canadian economy, rather than an exact copy, and so the goal is to develop reasonable approximations for effects such as technological learning. As a result, GEEM follows the practice of other major modelling groups[40], and represents technological learning through a log-linear experience function. The impact of knowledge and experience on CCS costs was previously modelled in GEEM as a 15% decline in the capital costs of CCS for every doubling of production. The cost decline function is applied from 2002, which is the starting year for modeling runs, but since deployment of CCS in Alberta is not modeled to occur until 2016, cost declines do not take effect until after this time. MKJA's selection of a 15% learning rate was based on the approach used in MIT's EPPA model[41], and was within the range presented in the Intergovernmental Panel on Climate Change (IPCC)'s report on CCS. That report suggested that costs would decline by between 12% and 20% every time that production doubled, based on historical experiences with SO_2 and NO_x capture systems and other engineered processes.[42]

However, MIT and the IPCC's estimates were published between 2004 and 2005. Since this time, a substantial amount of research and development has taken place, and new pilot and demonstration projects have come online. MKJA reviewed the current research on CCS experience curves, and the approaches taken by other modelers in order to determine if we should update the learning rate algorithm that is applied to CCS technologies in GEEM.

The literature review revealed that most researchers have focused entirely on how the costs of power plant CCS applications will decline over time, and have not investigated learning rates related to other industrial applications. Of the research that has been done on technological learning for CCS, very few studies provide quantitative estimates that are relevant to the modeling process. Instead, most of the literature investigates

[40] Yeh S and E Rubin, 2010, *Uncertainties in Technology Experience Curves for Energy-Economic Models*; IEA Greenhouse Gas R&D Programme (IEA GHG), 2006, *Estimating future trends in the cost of CO_2 capture technologies*.
[41] Jacoby H et al, 2004, *Technology and technical change in the MIT EPPA Model*.
[42] Intergovernmental Panel on Climate Change, 2005, *Carbon Capture and Storage*.

the shape of CCS learning curves in a qualitative manner, provides single point-in-time estimates, or estimates of learning rates for complete power plants, rather than for just the CO_2 capture component. The most applicable research was determined to be that conducted by the International Energy Agency (IEA) and McKinsey & Company, which is summarized below. An overview of ICO_2N's approach to addressing technological learning for CCS in their modeling work is also provided for comparison.

International Energy Agency[43]

The International Energy Agency (IEA) analyzed the cost reductions that have been achieved for seven technologies that they believe are analogous to technologies used in power plants with carbon capture and used that information to predict potential future cost trends for power plants with carbon capture. Learning rates were derived for both capital costs and operating and maintenance (O&M) costs for each analogous technology, with the learning rate representing the percentage reduction in costs associated with each doubling of cumulative production or capacity. The results are shown in Table 32.

Table 32: Learning Rates for Technologies Analogous to CCS

Technology	*Learning Rate*		*Did Costs Increase During Early Commercialisation?*
	Capital Cost	*O&M Cost*	
Flue gas desulfurisation (FGD)	0.11	0.22	Yes
Selective catalytic reduction (SCR)	0.12	0.13	Yes
Gas turbine combined cycle	0.1	0.06	Yes
Pulverised coal boilers	0.05	0.07-0.3	n/a
LNG production	0.14	0.12	Yes
Oxygen production	0.1	0.05	n/a
Hydrogen production (SMR)	0.27	0.27	n/a

The learning rates for these technologies were used to estimate future reductions in costs for power plants with carbon capture. This was done by breaking each type of power plant with carbon capture down into sub-systems, applying the learning rate from the most analogous technology, and then combining these to develop estimates of how costs would evolve for the entire power plant. Because we are interested in the reductions in capital costs for CO_2 capture technologies, the estimate that is relevant is that for the amine scrubbing CO_2 capture sub-system. The researchers believe that FGD is the most analogous technology, and so assume that the capital cost learning rate will be 11%, with a potential range of 6-17%.

[43] IEA GHG 2006

McKinsey & Company[44]

McKinsey & Company's analysis focused on estimating the costs associated with CCS at new-build coal-fired power plants. Their cost estimates generally apply to all components of the CCS value chain, including CO_2 capture, transportation and storage, and their focus is on European deployment. In contrast to the IEA's approach, McKinsey & Company's analysis are developed in a bottom-up manner, based on a review of the main CCS technologies applicable to coal-fired power plants. The researchers estimated costs for CCS at the demonstration stage, early commercial stage, and mature commercial stage. Once CCS deployment is in the early commercial stage (development of full scale projects, with an estimated size of 900 MW, and estimated in-service dates of 2020 and beyond), they estimate that learning effects could potentially produce a reduction in capital costs of around 12% for each doubling of capacity installed, and an absolute 1% reduction of the efficiency penalty. McKinsey & Company also estimates that the total cost of CCS (including capture, transportation, and storage) will decline by approximately 50% between 2010 and 2010, based on an assumption that 80-120 projects have been developed in Europe by 2030. They note that this aggregate cost reduction estimate is consistent with other estimates in the literature.

ICO_2N

In their model of CCS deployment in Alberta, ICO_2N accounts for technological learning through a 'Technology Capital Improvement Factor' of 5% annually. This factor is applied across all CCS technologies, starting in the fifth year after the first deployment of CCS. When combined with an assumed cost inflation factor of 2%, this leads to a net decrease in capital costs of 3% per year. ICO_2N developed this factor partly based on historical experience with SO_2 and NO_x reduction technologies. The delay in applying the factor until the fifth year after CCS deployment is designed to account for the fact that CCS costs may still be rising, since a full scale CCS installation has not yet been built in Alberta.

Recommendation

Based on our review of the literature, and after consultation with the Steering Committee, MKJA decided to update the CCS learning rate in the GEEM model to 11% for capital costs, and to add a 22% operation and maintenance costs learning rate (to match the IEA's estimate of the learning rate for amine scrubbing CO_2 capture technologies), and to calibrate the model to achieve a 50% decline in capital costs by 2030 under an aggressive deployment scenario. Given the uncertainties involved, we believe that it is sufficient to use a single function to approximate the cost declines with experience across all CCS technologies. We have chosen not to include a cost increase function during the early years of CCS deployment, particularly since our modeling does not show CCS deployment in Alberta until 2016, by which point international experience may have moved CCS onto the declining portion of the cost curve. Due to the inherent

[44] McKinsey & Company, 2008, *Carbon Capture & Storage: Assessing the Economics*.

uncertainties in these estimates, we do not believe that adding additional detail to the CCS experience algorithm would increase the accuracy or usefulness of our macroeconomic modeling results.

Feedback from the steering committee revealed that they were aware of significant progress in solid absorption carbon capture technologies, with some companies targeting a $15/tonne capture cost. Based on this, the steering committee was fairly confident that a 50% reduction in capture costs could be achieved by 2020. MKJA conducted a sensitivity analysis where the cumulative decline in CCS capital costs is 50% by 2020 (rather than 2030) in order to assess the potential economic impacts of this scenario.

Appendix 3: Detailed Quantitative Results

This appendix provides detailed results for all scenarios using base assumptions. Details on the sensitivity analysis are available upon request. Furthermore, additional information on the scenarios using base assumptions may be available upon request.

Current policies, no CCS

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	NA	NA	NA	NA
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	8.4	7.4	6.3	5.3
Bitumen extraction	25.3	37.2	58.5	82.7	110.8
Bitumen upgrading	1.5	1.9	2.4	2.8	3.6
Natural gas extraction	14.5	18.9	18.4	17.7	16.5
Other resource sectors	2.9	2.8	2.7	2.7	2.7
Electricity generation	1.5	1.9	1.9	2.0	2.1
Manufacturing industry					
Chemicals	2.8	2.6	2.4	2.4	2.3
Non-metallic minerals	0.6	0.6	0.6	0.7	0.7
Petroleum refining	1.9	1.7	1.5	1.2	1.2
Primary metals	0.3	0.3	0.3	0.3	0.3
Paper	0.8	0.8	0.8	0.8	0.8
Small manufacturing	6.2	5.9	5.8	5.9	6.0
Transportation	7.8	8.1	8.1	8.3	8.3
Services	75.9	80.1	86.0	94.4	104.0
Government	19.6	24.0	30.3	37.6	46.9
Total	171.9	195.2	227.1	265.7	311.5
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	8.2	9.3	10.7	12.3
Corporate income taxes	3.0	3.5	4.2	5.0	5.9
Provincial sales taxes	0.8	0.9	0.9	1.0	1.1
Other indirect taxes and subsidies	5.7	6.1	6.8	7.6	8.6
Oil and gas royalties					
Conventional oil extraction	2.3	1.9	1.6	1.4	1.1
Bitumen extraction	3.2	5.2	9.7	15.0	21.9
Natural gas extraction	2.1	2.5	2.4	2.3	2.1
Total	24.4	28.3	34.8	42.9	53.0

Oil and gas production					
	2010	2015	2020	2025	2030
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	215	176	145
Heavy	144	110	84	64	49
In-situ bitumen	638	930	1,281	1,719	2,214
Mined bitumen	831	1,138	1,568	2,014	2,521
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	1,195	1,704	2,317	3,020
Synthetic crude oil	592	771	1,012	1,251	1,516
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	3.1	3.6	4.1	4.2

Enhanced Oil Recovery Information					
	2010	2015	2020	2025	2030
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (Mt CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (2002$ billion)	NA	NA	NA	NA	NA
Incremental oil production (thousand barrel per day)	NA	NA	NA	NA	NA
Royalties from EOR (2002$ billion)	NA	NA	NA	NA	NA

Greenhouse Gas Emissions (Mt CO_2e)					
	2010	2015	2020	2025	2030
Oil and gas					
Conventional oil extraction	11	8	7	5	4
Bitumen extraction	29	39	51	64	77
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	27	25	23	20
Other resource sectors	3	3	3	3	3
Electricity generation	56	62	68	74	80
Manufacturing industry					
Chemicals	16	17	18	19	19
Non-metallic minerals	2	3	3	3	4
Petroleum refining	8	9	9	9	7
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	9	8	8	8
Transportation	10	11	12	12	12
Services	14	15	16	16	17
Government	3	3	4	4	5
Households	18	19	20	21	23
Total	209	227	244	262	281

Current policies, with CCS

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	NA	NA	NA	NA
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	8.4	7.4	9.4	6.5
Bitumen extraction	25.3	37.2	58.5	81.2	110.3
Bitumen upgrading	1.5	1.9	2.4	2.8	3.6
Natural gas extraction	14.5	18.9	18.4	17.6	16.5
Other resource sectors	2.9	2.8	2.7	2.6	2.8
Electricity generation	1.5	1.9	1.9	3.0	2.5
Manufacturing industry					
Chemicals	2.8	2.6	2.4	2.3	2.3
Non-metallic minerals	0.6	0.6	0.6	0.7	0.7
Petroleum refining	1.9	1.7	1.5	1.2	1.2
Primary metals	0.3	0.3	0.3	0.3	0.3
Paper	0.8	0.8	0.8	0.8	0.8
Small manufacturing	6.2	5.9	5.8	5.8	6.1
Transportation	7.8	8.1	8.1	8.1	8.4
Services	75.9	80.1	86.0	93.8	103.6
Government	19.6	24.0	30.4	37.7	46.8
Total	171.9	195.2	227.2	267.3	312.3
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	8.2	9.3	10.6	12.3
Corporate income taxes	3.0	3.5	4.2	5.0	5.9
Provincial sales taxes	0.8	0.9	0.9	1.0	1.1
Other indirect taxes and subsidies	5.7	6.1	6.8	7.6	8.6
Oil and gas royalties					
Conventional oil extraction	2.3	1.9	1.6	2.0	1.4
Bitumen extraction	3.2	5.2	9.7	14.7	21.7
Natural gas extraction	2.1	2.5	2.4	2.3	2.1
Total	24.4	28.3	34.9	43.1	53.1

Oil and gas production					
	2010	**2015**	**2020**	**2025**	**2030**
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	215	271	184
Heavy	144	110	84	64	49
In-situ bitumen	638	930	1,281	1,706	2,204
Mined bitumen	831	1,138	1,568	2,000	2,510
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	1,195	1,704	2,393	3,167
Synthetic crude oil	592	771	1,012	1,159	1,367
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	3.1	3.6	4.1	4.2

Enhanced Oil Recovery Information					
	2010	**2015**	**2020**	**2025**	**2030**
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	81	81	79
CO_2-EOR sales (Mt CO_2)	NA	NA	NA	0	0
CO_2-EOR sales (2002$ billion)	NA	NA	NA	1	1
Incremental oil production (thousand barrel per day)	NA	NA	NA	146	121
Royalties from EOR (2002$ billion)	NA	NA	NA	1	1

Greenhouse Gas Emissions (Mt CO_2e)					
	2010	**2015**	**2020**	**2025**	**2030**
Oil and gas					
Conventional oil extraction	11	8	7	5	3
Bitumen extraction	29	39	51	63	77
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	27	25	23	20
Other resource sectors	3	3	3	3	3
Electricity generation	56	62	68	52	71
Manufacturing industry					
Chemicals	16	17	18	19	19
Non-metallic minerals	2	3	3	3	4
Petroleum refining	8	9	9	9	7
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	9	8	8	8
Transportation	10	11	12	12	12
Services	14	15	16	16	17
Government	3	3	4	4	5
Households	18	19	20	21	23
Total	209	227	244	239	271

Current policies, no CCS, no Keystone XL

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	NA	NA	NA	NA
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	8.4	7.8	7.3	6.4
Bitumen extraction	25.3	37.2	52.2	61.9	79.4
Bitumen upgrading	1.5	1.9	2.9	4.2	6.1
Natural gas extraction	14.5	18.9	19.7	21.1	20.6
Other resource sectors	2.9	2.8	3.1	4.0	4.6
Electricity generation	1.5	1.9	2.0	2.2	2.4
Manufacturing industry					
Chemicals	2.8	2.6	2.6	3.1	3.4
Non-metallic minerals	0.6	0.6	0.7	0.8	0.9
Petroleum refining	2.0	1.8	1.4	0.8	0.9
Primary metals	0.3	0.3	0.3	0.3	0.4
Paper	0.8	0.8	0.9	1.2	1.5
Small manufacturing	6.2	5.9	6.2	7.5	8.6
Transportation	7.8	8.1	8.7	10.1	11.2
Services	75.9	80.1	87.4	98.5	109.7
Government	19.6	24.1	28.7	32.9	39.3
Total	171.9	195.2	224.6	255.9	295.2
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	8.2	9.1	10.4	12.0
Corporate income taxes	3.0	3.5	4.1	4.7	5.5
Provincial sales taxes	0.8	0.9	1.0	1.1	1.2
Other indirect taxes and subsidies	5.7	6.1	6.9	7.7	8.7
Oil and gas royalties					
Conventional oil extraction	2.3	1.9	1.7	1.6	1.4
Bitumen extraction	3.2	5.2	8.2	9.9	13.6
Natural gas extraction	2.1	2.5	2.5	2.7	2.5
Total	24.4	28.3	33.5	38.0	44.8

Oil and gas production					
	2010	**2015**	**2020**	**2025**	**2030**
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	215	176	145
Heavy	144	110	84	64	49
In-situ bitumen	638	929	1,249	1,520	1,835
Mined bitumen	831	1,138	1,532	1,804	2,122
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	1,195	1,575	1,651	1,675
Synthetic crude oil	592	771	1,066	1,478	2,016
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	3.1	3.6	4.3	4.5
Enhanced Oil Recovery Information					
	2010	**2015**	**2020**	**2025**	**2030**
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (Mt CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (2002$ billion)	NA	NA	NA	NA	NA
Incremental oil production (thousand barrel per day)	NA	NA	NA	NA	NA
Royalties from EOR (2002$ billion)	NA	NA	NA	NA	NA
Greenhouse Gas Emissions (Mt CO_2e)					
	2010	**2015**	**2020**	**2025**	**2030**
Oil and gas					
Conventional oil extraction	11	8	7	5	4
Bitumen extraction	29	39	50	56	64
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	27	25	23	21
Other resource sectors	3	3	3	3	3
Electricity generation	56	62	68	74	80
Manufacturing industry					
Chemicals	16	17	18	20	23
Non-metallic minerals	2	3	3	4	4
Petroleum refining	8	9	9	6	4
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	9	8	9	9
Transportation	10	11	12	13	14
Services	14	15	16	17	17
Government	3	3	3	4	4
Households	18	19	20	21	22
Total	209	227	243	255	271

Current policies, no CCS, no pipelines after Keystone XL

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	NA	NA	NA	NA
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	8.4	7.4	7.2	6.3
Bitumen extraction	25.3	37.2	58.5	66.5	82.7
Bitumen upgrading	1.5	1.9	2.4	3.8	5.8
Natural gas extraction	14.5	18.9	18.4	20.6	20.3
Other resource sectors	2.9	2.8	2.7	3.7	4.4
Electricity generation	1.5	1.9	1.9	2.2	2.4
Manufacturing industry					
Chemicals	2.8	2.6	2.4	2.9	3.3
Non-metallic minerals	0.6	0.6	0.6	0.8	0.9
Petroleum refining	2.0	1.8	1.5	1.0	0.8
Primary metals	0.3	0.3	0.3	0.3	0.4
Paper	0.8	0.8	0.8	1.1	1.4
Small manufacturing	6.2	5.9	5.8	7.1	8.3
Transportation	7.8	8.1	8.1	9.7	10.9
Services	75.9	80.1	86.0	97.5	109.2
Government	19.6	24.1	30.3	33.4	39.9
Total	171.9	195.2	227.1	257.8	296.9
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	8.2	9.3	10.4	12.0
Corporate income taxes	3.0	3.5	4.2	4.8	5.5
Provincial sales taxes	0.8	0.9	0.9	1.1	1.2
Other indirect taxes and subsidies	5.7	6.1	6.8	7.8	8.7
Oil and gas royalties					
Conventional oil extraction	2.3	1.9	1.6	1.5	1.3
Bitumen extraction	3.2	5.2	9.7	10.8	14.3
Natural gas extraction	2.1	2.5	2.4	2.6	2.5
Total	24.4	28.3	34.8	39.0	45.6

Oil and gas production					
	2010	***2015***	***2020***	***2025***	***2030***
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	215	176	145
Heavy	144	110	84	64	49
In-situ bitumen	638	929	1,281	1,610	1,908
Mined bitumen	831	1,138	1,568	1,900	2,200
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	1,195	1,704	1,946	1,925
Synthetic crude oil	592	771	1,011	1,381	1,928
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	3.1	3.6	4.2	4.4

Enhanced Oil Recovery Information					
	2010	***2015***	***2020***	***2025***	***2030***
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (Mt CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (2002$ billion)	NA	NA	NA	NA	NA
Incremental oil production (thousand barrel per day)	NA	NA	NA	NA	NA
Royalties from EOR (2002$ billion)	NA	NA	NA	NA	NA

Greenhouse Gas Emissions (Mt CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	11	8	7	5	4
Bitumen extraction	29	39	51	60	66
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	27	25	23	21
Other resource sectors	3	3	3	3	3
Electricity generation	56	62	68	74	80
Manufacturing industry					
Chemicals	16	17	18	20	22
Non-metallic minerals	2	3	3	3	4
Petroleum refining	8	9	9	6	5
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	9	8	9	9
Transportation	10	11	12	13	14
Services	14	15	16	17	18
Government	3	3	4	4	4
Households	18	19	20	21	22
Total	209	227	244	258	274

Current policies, with CCS to avoid pipeline ban

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	NA	NA	NA	NA
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	8.4	10.9	13.3	10.5
Bitumen extraction	25.3	37.2	56.4	76.9	103.9
Bitumen upgrading	1.5	1.9	2.3	2.4	3.0
Natural gas extraction	14.5	18.9	18.6	18.1	17.1
Other resource sectors	2.9	2.8	2.7	2.8	3.0
Electricity generation	1.5	1.9	1.9	2.1	2.1
Manufacturing industry					
Chemicals	2.8	2.6	2.4	2.4	2.5
Non-metallic minerals	0.6	0.6	0.6	0.7	0.7
Petroleum refining	1.9	1.7	1.6	1.2	1.3
Primary metals	0.3	0.3	0.3	0.3	0.3
Paper	0.8	0.8	0.8	0.8	0.9
Small manufacturing	6.2	5.9	5.8	6.0	6.4
Transportation	7.8	8.1	8.2	8.4	8.8
Services	75.9	80.1	85.4	93.4	102.9
Government	19.6	24.0	30.2	37.1	45.4
Total	171.9	195.2	228.3	265.9	308.8
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	8.2	9.2	10.5	12.0
Corporate income taxes	3.0	3.5	4.2	5.1	5.9
Provincial sales taxes	0.8	0.9	0.9	1.0	1.1
Other indirect taxes and subsidies	5.7	6.1	6.8	7.5	8.5
Oil and gas royalties					
Conventional oil extraction	2.3	1.9	2.5	2.8	2.2
Bitumen extraction	3.2	5.2	8.9	13.5	19.9
Natural gas extraction	2.1	2.5	2.4	2.3	2.1
Total	24.4	28.3	34.9	42.6	51.8

Oil and gas production					
	2010	**2015**	**2020**	**2025**	**2030**
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	351	391	295
Heavy	144	110	84	64	49
In-situ bitumen	638	930	1,187	1,517	1,920
Mined bitumen	831	1,138	1,538	1,955	2,450
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	1,195	1,714	2,337	3,061
Synthetic crude oil	592	771	893	1,002	1,157
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	3.1	3.6	4.1	4.3
Enhanced Oil Recovery Information					
	2010	**2015**	**2020**	**2025**	**2030**
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	70	2	2
CO_2-EOR sales (Mt CO_2)	NA	NA	0	0	0
CO_2-EOR sales (2002$ billion)	NA	NA	1	0	0
Incremental oil production (thousand barrel per day)	NA	NA	166	263	199
Royalties from EOR (2002$ billion)	NA	NA	1	2	2
Greenhouse Gas Emissions (Mt CO_2e)					
	2010	**2015**	**2020**	**2025**	**2030**
Oil and gas					
Conventional oil extraction	11	8	6	4	3
Bitumen extraction	29	39	30	30	31
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	27	25	23	21
Other resource sectors	3	3	3	3	3
Electricity generation	56	62	68	71	79
Manufacturing industry					
Chemicals	16	17	18	19	20
Non-metallic minerals	2	3	3	3	4
Petroleum refining	8	9	9	9	8
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	9	8	8	8
Transportation	10	11	12	12	13
Services	14	15	16	16	17
Government	3	3	4	4	5
Households	18	19	20	21	23
Total	209	227	222	226	234

Current policies, no CCS, U.S. low-carbon fuel standard

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	NA	NA	NA	NA
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	9.0	8.5	7.4	6.3
Bitumen extraction	25.3	26.5	37.2	54.4	76.4
Bitumen upgrading	1.5	2.4	3.6	4.8	6.3
Natural gas extraction	14.5	20.9	22.2	22.1	20.8
Other resource sectors	2.9	3.5	4.0	4.4	4.6
Electricity generation	1.5	2.1	2.2	2.3	2.4
Manufacturing industry					
Chemicals	2.8	2.9	3.2	3.4	3.5
Non-metallic minerals	0.6	0.7	0.7	0.8	0.9
Petroleum refining	1.9	0.9	0.9	0.7	1.1
Primary metals	0.3	0.3	0.3	0.3	0.4
Paper	0.8	1.0	1.2	1.4	1.6
Small manufacturing	6.2	6.8	7.5	8.2	8.8
Transportation	7.8	9.3	10.2	11.0	11.6
Services	75.9	83.2	90.5	99.7	109.9
Government	19.6	22.3	26.2	32.1	39.3
Total	171.9	191.7	218.5	252.8	293.9
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	8.1	9.1	10.5	12.1
Corporate income taxes	3.0	3.4	3.9	4.6	5.4
Provincial sales taxes	0.8	0.9	1.0	1.1	1.2
Other indirect taxes and subsidies	5.7	6.2	6.9	7.7	8.6
Oil and gas royalties					
Conventional oil extraction	2.3	2.0	1.8	1.6	1.3
Bitumen extraction	3.2	3.3	5.1	8.5	13.2
Natural gas extraction	2.1	2.7	2.8	2.8	2.6
Total	24.4	26.6	30.6	36.7	44.4

Oil and gas production					
	2010	***2015***	***2020***	***2025***	***2030***
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	215	176	145
Heavy	144	110	84	64	49
In-situ bitumen	638	830	1,037	1,325	1,704
Mined bitumen	831	1,013	1,271	1,591	1,976
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	864	928	1,079	1,288
Synthetic crude oil	592	864	1,219	1,622	2,113
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	3.2	3.8	4.4	4.5
Enhanced Oil Recovery Information					
	2010	***2015***	***2020***	***2025***	***2030***
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (Mt CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (2002$ billion)	NA	NA	NA	NA	NA
Incremental oil production (thousand barrel per day)	NA	NA	NA	NA	NA
Royalties from EOR (2002$ billion)	NA	NA	NA	NA	NA
Greenhouse Gas Emissions (Mt CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	11	8	7	5	4
Bitumen extraction	29	34	40	48	58
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	27	25	23	21
Other resource sectors	3	3	3	4	4
Electricity generation	56	62	68	74	81
Manufacturing industry					
Chemicals	16	18	20	22	24
Non-metallic minerals	2	3	3	4	4
Petroleum refining	8	9	6	6	5
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	9	9	10	10
Transportation	10	12	13	14	15
Services	14	15	16	17	17
Government	3	3	3	4	4
Households	18	19	19	20	22
Total	209	224	236	251	270

Current policies, with CCS, U.S. low-carbon fuel standard

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	NA	NA	NA	NA
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	9.0	11.3	13.3	10.5
Bitumen extraction	25.3	26.5	49.6	69.2	94.5
Bitumen upgrading	1.5	2.4	5.8	7.2	9.7
Natural gas extraction	14.5	20.9	19.0	18.4	17.3
Other resource sectors	2.9	3.5	2.8	2.9	3.1
Electricity generation	1.5	2.1	2.0	2.1	2.2
Manufacturing industry					
Chemicals	2.8	2.9	2.5	2.5	2.5
Non-metallic minerals	0.6	0.7	0.6	0.7	0.8
Petroleum refining	1.9	0.9	1.6	1.2	1.3
Primary metals	0.3	0.3	0.3	0.3	0.3
Paper	0.8	1.0	0.9	0.9	0.9
Small manufacturing	6.2	6.8	6.0	6.2	6.6
Transportation	7.8	9.3	8.6	8.7	9.0
Services	75.9	83.2	86.9	94.9	104.9
Government	19.6	22.3	29.2	36.1	44.0
Total	171.9	191.7	227.1	264.6	307.5
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	8.1	9.3	10.5	12.2
Corporate income taxes	3.0	3.4	4.1	5.0	5.8
Provincial sales taxes	0.8	0.9	0.9	1.0	1.1
Other indirect taxes and subsidies	5.7	6.2	6.8	7.6	8.7
Oil and gas royalties					
Conventional oil extraction	2.3	2.0	2.6	2.8	2.2
Bitumen extraction	3.2	3.3	7.3	11.8	17.6
Natural gas extraction	2.1	2.7	2.4	2.3	2.2
Total	24.4	26.6	33.5	41.1	49.7

Oil and gas production					
	2010	***2015***	***2020***	***2025***	***2030***
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	368	389	292
Heavy	144	110	84	64	49
In-situ bitumen	638	830	1,089	1,404	1,800
Mined bitumen	831	1,013	1,418	1,832	2,313
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	864	931	1,092	1,279
Synthetic crude oil	592	864	1,392	1,894	2,503
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	3.2	3.6	4.1	4.3
Enhanced Oil Recovery Information					
	2010	***2015***	***2020***	***2025***	***2030***
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	69	2	2
CO_2-EOR sales (Mt CO_2)	NA	NA	0	0	0
CO_2-EOR sales (2002$ billion)	NA	NA	1	0	0
Incremental oil production (thousand barrel per day)	NA	NA	186	262	196
Royalties from EOR (2002$ billion)	NA	NA	1	2	2
Greenhouse Gas Emissions (Mt CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	11	8	6	4	3
Bitumen extraction	29	34	26	27	28
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	27	25	23	21
Other resource sectors	3	3	3	3	3
Electricity generation	56	62	68	73	80
Manufacturing industry					
Chemicals	16	18	19	19	20
Non-metallic minerals	2	3	3	3	4
Petroleum refining	8	9	10	9	8
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	9	8	8	8
Transportation	10	12	12	13	13
Services	14	15	16	17	17
Government	3	3	3	4	5
Households	18	19	20	21	23
Total	209	224	221	226	234

Emissions stabilization, no CCS

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	21	29	91	155
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	8.2	7.1	6.2	5.3
Bitumen extraction	25.3	35.5	52.7	70.7	91.8
Bitumen upgrading	1.5	1.8	2.4	3.1	4.0
Natural gas extraction	14.5	19.1	19.3	18.6	17.8
Other resource sectors	2.9	2.9	3.0	3.2	3.6
Electricity generation	1.5	2.3	2.4	3.3	3.4
Manufacturing industry					
Chemicals	2.8	2.6	2.5	2.6	2.1
Non-metallic minerals	0.6	0.6	0.7	0.8	1.0
Petroleum refining	1.9	1.8	1.7	1.9	2.1
Primary metals	0.3	0.3	0.3	0.3	0.4
Paper	0.8	0.8	0.9	1.0	1.1
Small manufacturing	6.2	6.0	6.3	6.8	7.5
Transportation	7.8	8.3	8.9	9.8	10.7
Services	75.9	79.8	86.9	94.9	103.5
Government	19.6	23.2	28.2	32.6	38.0
Total	171.9	193.3	223.4	255.9	292.4
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	8.0	9.0	10.0	11.1
Corporate income taxes	3.0	3.4	4.0	4.4	5.0
Provincial sales taxes	0.8	0.9	1.0	1.1	1.2
Other indirect taxes and subsidies	5.7	6.1	6.8	7.6	8.4
Oil and gas royalties					
Conventional oil extraction	2.3	1.8	1.6	1.3	1.1
Bitumen extraction	3.2	4.9	8.2	11.4	15.6
Natural gas extraction	2.1	2.5	2.5	2.4	2.2
Total	24.4	27.6	32.9	38.2	44.6

Oil and gas production					
	2010	**2015**	**2020**	**2025**	**2030**
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	215	176	145
Heavy	144	110	84	64	49
In-situ bitumen	638	904	1,205	1,532	1,879
Mined bitumen	831	1,116	1,496	1,849	2,237
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	1,209	1,679	2,210	2,814
Synthetic crude oil	592	716	903	1,034	1,150
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	3.1	3.6	4.0	4.0

Enhanced Oil Recovery Information					
	2010	**2015**	**2020**	**2025**	**2030**
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (Mt CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (2002$ billion)	NA	NA	NA	NA	NA
Incremental oil production (thousand barrel per day)	NA	NA	NA	NA	NA
Royalties from EOR (2002$ billion)	NA	NA	NA	NA	NA

Greenhouse Gas Emissions (Mt CO_2e)					
	2010	**2015**	**2020**	**2025**	**2030**
Oil and gas					
Conventional oil extraction	11	8	6	4	2
Bitumen extraction	29	37	47	55	62
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	26	23	20	16
Other resource sectors	3	3	3	3	3
Electricity generation	56	52	51	27	18
Manufacturing industry					
Chemicals	16	16	17	16	10
Non-metallic minerals	2	2	2	2	2
Petroleum refining	8	9	9	8	6
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	8	8	8	8
Transportation	10	11	12	12	13
Services	14	15	16	16	16
Government	3	3	3	4	4
Households	18	19	20	21	22
Total	209	213	217	197	183

Emissions stabilization, with CCS

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	21	26	62	106
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	8.2	7.4	11.7	9.4
Bitumen extraction	25.3	35.5	52.5	68.8	89.8
Bitumen upgrading	1.5	1.8	2.5	2.9	3.8
Natural gas extraction	14.5	19.1	19.3	18.5	17.9
Other resource sectors	2.9	2.9	3.0	3.2	3.7
Electricity generation	1.5	2.3	2.4	3.4	3.3
Manufacturing industry					
Chemicals	2.8	2.6	2.5	2.6	2.6
Non-metallic minerals	0.6	0.6	0.7	0.8	0.9
Petroleum refining	1.9	1.8	1.7	1.9	2.0
Primary metals	0.3	0.3	0.3	0.3	0.4
Paper	0.8	0.8	0.9	1.0	1.1
Small manufacturing	6.2	6.0	6.3	6.7	7.5
Transportation	7.8	8.3	8.9	9.6	10.6
Services	75.9	79.8	86.9	95.0	104.5
Government	19.6	23.2	28.3	33.8	39.6
Total	171.9	193.3	223.6	260.1	297.2
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	8.0	9.0	10.2	11.4
Corporate income taxes	3.0	3.4	4.0	4.6	5.3
Provincial sales taxes	0.8	0.9	1.0	1.1	1.2
Other indirect taxes and subsidies	5.7	6.1	6.8	7.6	8.5
Oil and gas royalties					
Conventional oil extraction	2.3	1.8	1.6	2.6	2.0
Bitumen extraction	3.2	4.9	8.1	11.1	15.6
Natural gas extraction	2.1	2.5	2.5	2.4	2.2
Total	24.4	27.6	33.0	39.5	46.1

Oil and gas production					
	2010	***2015***	***2020***	***2025***	***2030***
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	224	379	273
Heavy	144	110	84	64	50
In-situ bitumen	638	904	1,204	1,496	1,851
Mined bitumen	831	1,116	1,496	1,830	2,218
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	1,209	1,695	2,212	2,780
Synthetic crude oil	592	716	888	984	1,139
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	3.1	3.5	3.9	4.0
Enhanced Oil Recovery Information					
	2010	***2015***	***2020***	***2025***	***2030***
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	62	44	2
CO_2-EOR sales (Mt CO_2)	NA	NA	0	0	0
CO_2-EOR sales (2002$ billion)	NA	NA	0	1	0
Incremental oil production (thousand barrel per day)	NA	NA	12	244	175
Royalties from EOR (2002$ billion)	NA	NA	0	2	1
Greenhouse Gas Emissions (Mt CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	11	8	6	4	1
Bitumen extraction	29	37	47	43	54
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	26	23	19	15
Other resource sectors	3	3	3	3	3
Electricity generation	56	52	51	20	6
Manufacturing industry					
Chemicals	16	16	17	16	15
Non-metallic minerals	2	2	2	2	2
Petroleum refining	8	9	9	8	6
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	8	8	8	8
Transportation	10	11	12	12	13
Services	14	15	16	16	16
Government	3	3	3	4	4
Households	18	19	20	21	23
Total	209	213	217	177	167

Deep reductions, no CCS

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	121	190	264	444
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	8.4	7.1	6.1	5.2
Bitumen extraction	25.3	32.8	44.2	54.4	64.6
Bitumen upgrading	1.5	2.4	2.7	2.3	0.8
Natural gas extraction	14.5	17.2	18.8	19.5	18.5
Other resource sectors	2.9	2.9	3.5	4.1	5.5
Electricity generation	1.5	3.2	3.2	3.0	3.2
Manufacturing industry					
Chemicals	2.8	2.4	1.8	1.5	1.4
Non-metallic minerals	0.6	0.7	0.9	1.0	1.1
Petroleum refining	1.9	2.3	2.3	2.7	2.6
Primary metals	0.3	0.3	0.3	0.4	0.5
Paper	0.8	0.8	0.9	1.2	1.5
Small manufacturing	6.2	6.1	6.9	8.1	9.7
Transportation	7.8	8.7	9.8	11.7	14.4
Services	75.9	78.3	84.4	92.3	101.5
Government	19.6	20.9	23.6	26.1	27.7
Total	171.9	187.4	210.4	234.4	258.2
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	7.5	8.1	8.8	9.5
Corporate income taxes	3.0	2.9	3.2	3.6	3.7
Provincial sales taxes	0.8	0.9	1.0	1.1	1.3
Other indirect taxes and subsidies	5.7	6.0	6.5	7.2	7.9
Oil and gas royalties					
Conventional oil extraction	2.3	1.9	1.6	1.3	1.1
Bitumen extraction	3.2	4.1	5.9	7.3	8.2
Natural gas extraction	2.1	2.3	2.4	2.4	2.3
Total	24.4	25.6	28.7	31.8	33.9

Oil and gas production					
	2010	***2015***	***2020***	***2025***	***2030***
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	215	176	144
Heavy	144	110	82	63	49
In-situ bitumen	638	835	1,035	1,210	1,332
Mined bitumen	831	1,069	1,366	1,595	1,809
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	1,159	1,664	2,281	2,988
Synthetic crude oil	592	658	651	463	135
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	2.9	3.2	3.5	3.5
Enhanced Oil Recovery Information					
	2010	***2015***	***2020***	***2025***	***2030***
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (Mt CO_2)	NA	NA	NA	NA	NA
CO_2-EOR sales (2002$ billion)	NA	NA	NA	NA	NA
Incremental oil production (thousand barrel per day)	NA	NA	NA	NA	NA
Royalties from EOR (2002$ billion)	NA	NA	NA	NA	NA
Greenhouse Gas Emissions (Mt CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	11	7	3	1	1
Bitumen extraction	29	34	39	42	42
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	25	21	17	12
Other resource sectors	3	3	3	3	3
Electricity generation	56	15	14	5	3
Manufacturing industry					
Chemicals	16	13	7	4	3
Non-metallic minerals	2	2	1	0	0
Petroleum refining	8	8	7	5	4
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	8	8	6	5
Transportation	10	11	11	12	12
Services	14	14	14	14	14
Government	3	3	3	3	3
Households	18	19	19	19	19
Total	209	163	150	132	121

Deep reductions, with CCS

Greenhouse gas price (2002$ / tonne CO_2e)					
	2010	***2015***	***2020***	***2025***	***2030***
Greenhouse gas price	NA	121	125	216	376
Gross Domestic Product (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Oil and gas					
Conventional oil extraction	10.3	8.4	12.2	10.6	7.2
Bitumen extraction	25.3	32.8	44.1	53.9	67.8
Bitumen upgrading	1.5	2.4	2.6	3.1	3.5
Natural gas extraction	14.5	17.2	18.6	19.6	18.6
Other resource sectors	2.9	2.9	3.3	4.2	5.0
Electricity generation	1.5	3.2	3.5	3.0	3.7
Manufacturing industry					
Chemicals	2.8	2.4	2.3	1.9	1.6
Non-metallic minerals	0.6	0.7	0.8	1.0	1.1
Petroleum refining	1.9	2.3	2.0	2.6	2.5
Primary metals	0.3	0.3	0.3	0.4	0.5
Paper	0.8	0.8	0.9	1.2	1.6
Small manufacturing	6.2	6.1	6.6	7.9	9.4
Transportation	7.8	8.7	9.6	11.2	13.6
Services	75.9	78.3	85.6	94.2	104.9
Government	19.6	20.9	25.7	28.3	31.1
Total	171.9	187.4	218.3	243.2	272.2
Government Revenues (2002$ billion)					
	2010	***2015***	***2020***	***2025***	***2030***
Personal income taxes	7.2	7.5	8.5	9.2	10.3
Corporate income taxes	3.0	2.9	3.7	4.1	4.4
Provincial sales taxes	0.8	0.9	1.0	1.1	1.3
Other indirect taxes and subsidies	5.7	6.0	6.7	7.3	8.2
Oil and gas royalties					
Conventional oil extraction	2.3	1.9	2.7	2.2	1.5
Bitumen extraction	3.2	4.1	6.0	7.8	9.5
Natural gas extraction	2.1	2.3	2.4	2.5	2.3
Total	24.4	25.6	31.0	34.2	37.4

Oil and gas production					
	2010	**2015**	**2020**	**2025**	**2030**
Crude oil extraction (thousand barrel per day)					
Light/medium	318	261	417	327	210
Heavy	144	110	84	64	49
In-situ bitumen	638	835	1,029	1,242	1,472
Mined bitumen	831	1,069	1,364	1,599	1,859
Products from oil sands (thousand barrel per day)					
Raw bitumen	799	1,159	1,547	2,056	2,394
Synthetic crude oil	592	658	747	694	828
Natural gas extraction (Bcf per day)					
Conventional	7.7	6.5	5.5	4.6	3.9
Unconventional	3.0	2.9	3.3	3.6	3.8

Enhanced Oil Recovery Information					
	2010	**2015**	**2020**	**2025**	**2030**
Price for CO_2-EOR (2002$ / tonne CO_2)	NA	NA	39	2	1
CO_2-EOR sales (Mt CO_2)	NA	NA	0	0	0
CO_2-EOR sales (2002$ billion)	NA	NA	1	0	0
Incremental oil production (thousand barrel per day)	NA	NA	265	220	142
Royalties from EOR (2002$ billion)	NA	NA	2	1	1

Greenhouse Gas Emissions (Mt CO_2e)					
	2010	**2015**	**2020**	**2025**	**2030**
Oil and gas					
Conventional oil extraction	11	7	3	1	1
Bitumen extraction	29	34	26	24	20
Bitumen upgrading	0	0	0	0	0
Natural gas extraction	30	25	20	13	6
Other resource sectors	3	3	3	3	3
Electricity generation	56	15	-5	0	-1
Manufacturing industry					
Chemicals	16	13	13	7	4
Non-metallic minerals	2	2	2	0	0
Petroleum refining	8	8	8	3	0
Primary metals	0	0	0	0	0
Paper	1	1	1	1	1
Small manufacturing	8	8	8	7	5
Transportation	10	11	11	12	12
Services	14	14	15	15	14
Government	3	3	3	3	3
Households	18	19	19	19	19
Total	209	163	125	108	87