Assessment of Greenhouse Gas Emission Mitigation Potential and Abatement Costs of Alternative Technology Options for Oil Sands

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Abstract

In the last several decades societies have gained an increasing level of awareness and scientific understanding of the impact of anthropogenic greenhouse gas (GHG) emissions on average global temperatures and the negative results of those temperatures increasing. Many governments, including Canada's, have formally recognized the need to reduce GHG emission levels, most recently through the Paris Agreement. In Canada, the oil sands industry has accounted for approximately 10% of the nation's annual GHG emissions making it an important area to address. However, the industry is also important to Canada's economy, contributing approximately 5% of the gross domestic product in recent years. This research evaluates emerging technology options applicable to the oil sands industry for their GHG abatement potential and marginal costs, presenting the first ever comprehensive analysis of technology options for the industry that uses a consistent evaluation framework. The framework consists of a combination of market penetration modelling and bottom-up energy accounting to determine GHG emissions and marginal costs of technology scenarios compared to a business-as-usual scenario. The market penetration modelling consists of a hybrid cost and diffusion model that assigns technologies annual market shares based on forecasted costs. The energy accounting model uses the Long-range Energy Alternatives Planning model (LEAP) to calculate energy demand and supply based on forecasted industry production levels. The framework is both transparent and simple to update with new information, making it an attractive tool for policymakers and industry stakeholders.

Four key classes of technologies were identified and evaluated using the framework. These were renewable/low carbon energy; carbon capture, utilization, and storage; advanced bitumen production techniques; and cogeneration of steam and electricity. A total of 84 scenarios were evaluated with 24 unique technology options and 3 carbon policy frameworks for the years 2020-

2050. Ten renewable/low carbon technologies were evaluated and were found to offer from 24 million tonnes to 116 million tonnes of cumulative GHG abatement potential at marginal costs of \$21/tCO_2e and \$2/tCO_2e, respectively. The top performing low carbon technology from these options was small modular nuclear reactors used to generate steam for in situ production with results as high as 82 million tonnes of GHG abatement potential. Four carbon capture, utilization, and storage technologies were evaluated and were found to offer from 92 million tonnes to 253 million tonnes of cumulative GHG abatement potential at marginal costs of \$31/tCO_2e and -\$30/tCO_2e, respectively. The top performing CCUS technology was oxyfuel boilers using fuels derived from produced bitumen with results as high as 246 million tonnes of GHG abatement potential. Three advanced bitumen production technologies were evaluated and were found to offer from 247 million tonnes to 267 million tonnes of cumulative GHG abatement potential at marginal costs of -\$39/tCO_2e and -\$47/tCO_2e, respectively. The top performing advanced extraction technology option was the solvent-steam hybrid system, with results as high as 85 million tonnes in GHG abatement potential. Cogeneration technology was considered in three subsectors of bitumen production and resulted in a range of 28 million tonnes to 40 million tonnes of GHG abatement potential with marginal costs of -\$109/tCO_2e and -\$266/tCO_2e, respectively. The top performing cogeneration scenario was cogeneration applied to the in situ sub sector, with results as high as 37 million tonnes of GHG abatement potential. These results provide an understanding of the technology options currently available to the oil sands industry, the feasible rates they could penetrate the market, and the benefits and costs of each option. This information ultimately provides quantified costs and environmental benefits of the evaluated technologies under one consistent framework to policymakers and industry stakeholders.

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Glossary of terms

AER – Alberta Energy Regulator

BAU – Business-as-usual

bbl – Barrel

Bpd – Barrels per day

CAD – Canadian dollar

CCS – Carbon capture and storage

CCIR – Carbon competitiveness incentive regulation

CCUS – Carbon capture, utilization, and storage

CERI – Canadian Energy Research Institute

CSS – Cyclic steam stimulation

dilbit – Diluted bitumen

EOR – Enhanced oil recovery

GJ – Gigajoule

IPCC – Intergovernmental Panel on Climate Change

IRR – Internal rate of return

kbpd – thousand barrels per day

LCA – Lifecycle analysis

LEAP – Long-range Energy Alternatives Planning

MJ – Megajoule

MT – Million tonnes

NEB – National Energy Board

PBMR – Pebble bed modular reactor

PCF – Pan-Canadian Framework on Clean Growth and Climate Change

PV – Photovoltaic

SAGD – Steam-assisted gravity drainage

SCO – Synthetic crude oil

SMR – Steam methane reforming

SOR – Steam-to-oil ratio

tCO_2e – Tonne of carbon dioxide equivalent

TED – Technology and Environment Database

TIER – Technology Innovation and Emission Regulation

UCG – Underground coal gasification

WEAP – Water Evaluation and Planning

1 Introduction

1.1 Climate change and Canadian GHG emissions

Many governments around the world recognize the need to reduce carbon emissions to avoid harming the function of natural systems on our planet. There is extensive scientific evidence suggesting anthropogenic carbon emissions impact the global climate, causing mean temperature increases and an increase in severe weather events dangerous for human life [1]. These changes also have substantial economic impacts, with many studies suggesting the long-term cost of not acting will be high [2]. Because of these concerns, the Paris Agreement was signed by 185 countries, and it outlines the commitments necessary to limit global warming to a 2°C increase in mean temperature by reducing carbon emissions [3]. Each country is responsible for outlining its plans to meet these commitments and regularly offering updates to the signatory group.

Canada was a signatory of the Paris Agreement and has implemented the Pan-Canadian Framework on Clean Growth and Climate Change (PCF) to address these commitments without negatively impacting the country's development [4]. On a global scale, Canada has a relatively high rate of carbon emissions per capita, at 15.1 tCO_2e/person in 2014, compared to the average 9.5t/person in other Organization for Economic Co-operation and Development (OECD) countries in the same year [5]. Some reasons for these high GHG emissions are that Canada has a relatively cold climate and requires higher energy use and that the nation is a major exporter of energy and goods and uses significant amounts of energy to produce these products. However, in order to meet the commitments of the Paris Agreement, Canada's high GHG emissions rate needs to be reduced considerably. The PCF identifies the industrial sector as a key area to address, as it accounts for 37% of Canadian GHG emissions [4].

Within the Canadian industrial sector, the oil sands industry in Alberta is a key contributor to GHG emissions and has been identified in both federal and provincial policies and plans as a vital area to address for GHG emission reductions. Figure 1-1 shows the GHG emission profiles for Canada and the province of Alberta in 2017. GHG emissions from the oil and gas sector in 2017 made up 27% of nationwide emissions at 195 Mt and 70% of Alberta's GHG emissions at 137 Mt. Of these GHG emissions, 81 Mt was from oil sands processes, 96% of which came from activities in Alberta. Therefore, oil sands processes were the source of approximately 11% of Canadian GHG emissions and 39% of Albertan GHG emissions in 2017 [6].

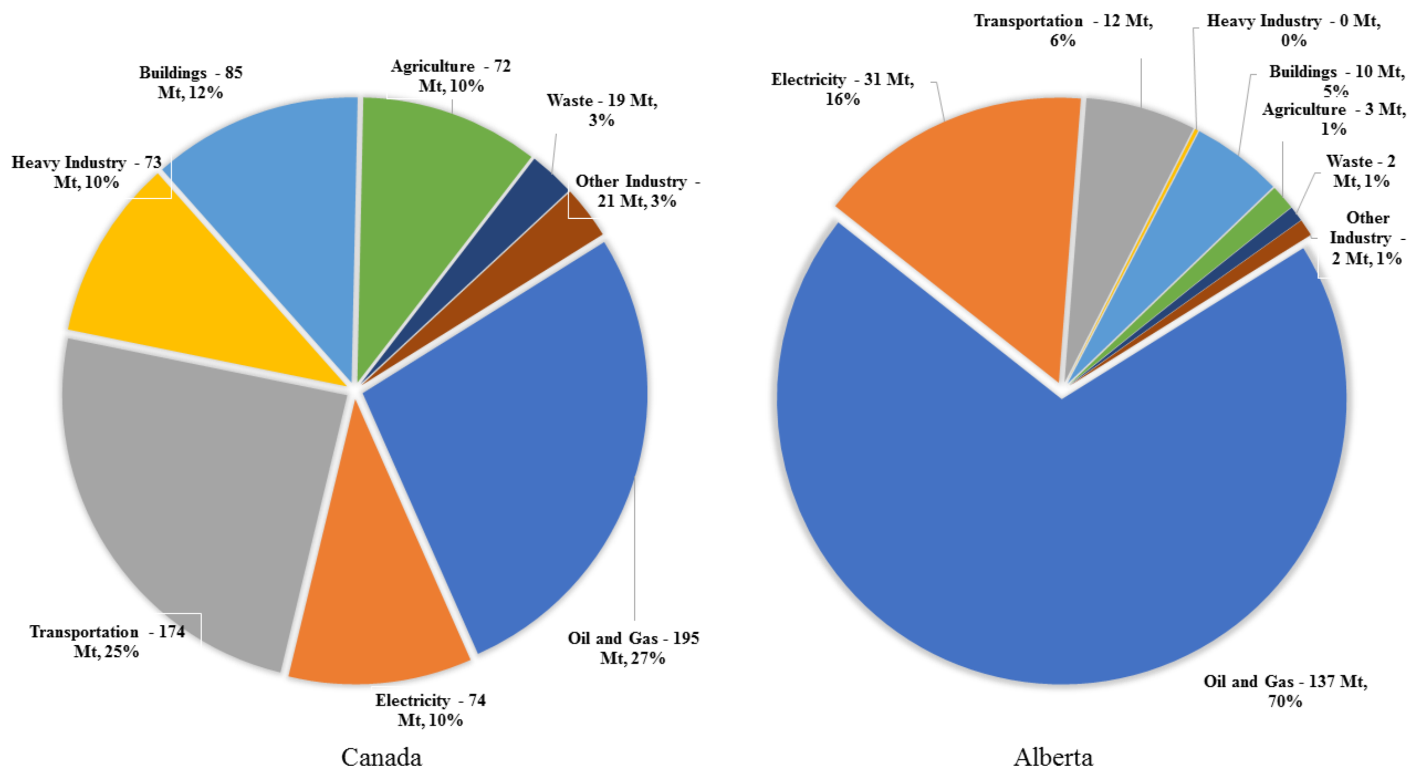


Figure 1-1: 2017 emission profiles [6]

Both the federal and provincial governments have enacted regulations and formed plans for reducing the high GHG emission levels from this industry. The federal government has addressed GHG emissions through a country-wide carbon pricing benchmark that all provinces must meet or exceed – \$50/tCO_2e by 2022 – in the Greenhouse Gas Pollution Pricing Act [7]. The federal government, through the PCF, also made commitments to support other levels of government in reducing industrial emissions and specifically identifies oil and gas activities as a focus area [4]. The Alberta government has enacted its own carbon pricing system with dedicated GHG emission benchmarks for bitumen production from oil sands [8] and legislated a 100 $MtCO_2e$ annual GHG emission cap on all bitumen production from oil sands to ensure the industry develops sustainably [9].

1.2 Oil sands background

Oil sands are a substance made up of crude bitumen and other mineral materials that are found in large quantities in the Canadian provinces of Alberta and Saskatchewan. Crude bitumen is a type of heavy crude oil characterized by high viscosity, generally greater than 500 Pa·s; high density, between 970 kg/m^3 and 1015 kg/m^3; and low hydrogen-to-carbon ratio [10]. The key processes used for producing and processing crude bitumen are shown in Figure 1-2 and described below. Crude bitumen from oil sands is produced either through surface mining or in situ techniques. Surface mining is used for ores near the surface and is similar to traditional mining, from which ores are dug from open pits and transported using mobile mining equipment. After ores are dug through surface mining, they are transported to an extraction facility where they are mixed with heated water to separate bitumen from sand. The bitumen is then collected and processed further and the sand is disposed of. In situ techniques are used when the reservoir is 200 m or more underground, and the resources are extracted through pumped wellbores [11]. Various techniques are used for in situ extraction, the most common being steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). These techniques both involve pumping steam into the reservoir to heat and reduce the viscosity of the bitumen, allowing it to be pumped to the surface.

Recent trends have shown overall growth in the oil sands industry and an increase in the share of in situ methods, especially SAGD, compared to surface mining. In 2010, 53% of bitumen produced was from surface mines, totaling 313 million bbl, while in 2017 the share of surface-mined product dropped to 46%, totaling 475 million bbl [12], with the remainder being produced through in situ techniques. Once bitumen is produced, it is either upgraded to higher quality synthetic crude oil (SCO) or diluted using lighter hydrocarbons and sold as diluted bitumen (dilbit). Bitumen upgrading has grown in the last decade, though not at the same rate as overall bitumen production. In 2009, approximately 263 million bbl were upgraded, representing 48% of total bitumen production, while in 2017, 384 million bbl were upgraded, representing 35% of total bitumen production [13, 14].

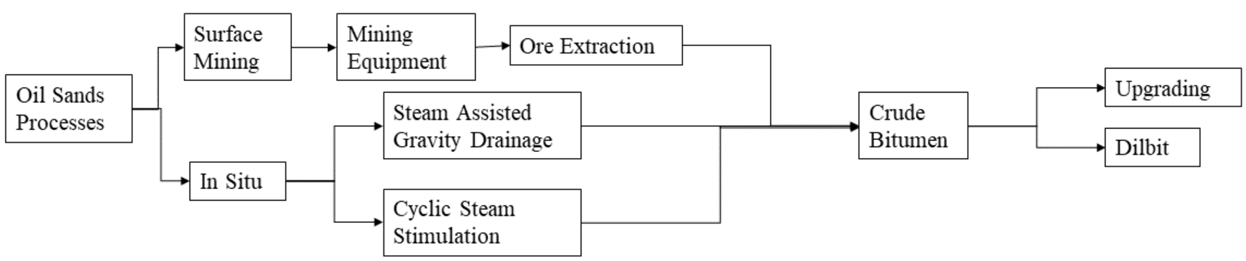


Figure 1-2: Overview of key oil sands production processes

The GHG emissions from the oil sands industry are a result of the energy requirements for producing crude bitumen and are generally higher than other forms of crude oil production. Life cycle GHG emissions from initial production to arrival at a refinery range from 12.3 gCO_2e/MJ to 33.6 gCO_2e/MJ, averaging 25.9 gCO_2e/MJ, whereas US conventional crude oil averages 7.1 gCO_2e/MJ [15]. The energy intensity and GHG emissions related to producing bitumen vary substantially depending on the production method. Current technologies used in oil sands processes are mainly powered by natural gas, electricity, or diesel fuel. Natural gas is used extensively for process heat in surface mining, steam generation for in situ processes, and for steam methane reforming in upgrading. Electricity is used for plant operation and equipment in all production methods as well as for some mobile mining equipment in surface mining. Electricity for oil sands operations is either generated on-site in natural gas cogeneration plants or sourced from the Alberta grid. Diesel fuel is used for mobile mining equipment. Natural gas consumption is considerably larger for in situ techniques, with estimates for SAGD plants without cogeneration at 148 MJ of natural gas per GJ of bitumen produced [16]. In contrast, surface mining plants are estimated at 74 MJ of natural gas per GJ of bitumen produced [16]. Steam production is responsible for the largest portion of industry GHG emissions, accounting for 50% of industry-wide carbon emissions, and is expected to be the key determinant of future emissions as well [17]. GHG emissions from SAGD range from 7.9-12.0 gCO2/MJ SCO and upgrading processes range from 6.3-7.9 gCO2/MJ SCO [17]. GHG emissions are estimated to be 95% CO_2 and future GHG emissions are expected to be similar and come mainly from steam generation through the growth of SAGD production [18]. As a result of growth in the oil sands industry, industrial natural gas demand increased 51% in Alberta from 2009 to 2012 [19], where oil sands accounted for 80% of the demand growth [20].

The oil sands industry, producing over 3100 kbpd of crude bitumen in 2018, is expected to grow by over 50% by 2050 in terms of daily bitumen production [13]. In 2016, the oil sands industry contributed approximately CAD$82.6 billion to the Canadian economy, representing about 5% of Canada's GDP [21]. The forecasted growth represents a strong economic opportunity for the nation; however, given the concerns raised about GHG emissions levels and international commitments to reduce Canada's GHG footprint, economically acceptable ways of reducing emissions from the industry are needed.

1.3 Options for reducing GHG emissions from the oil sands

Several technology classifications have been identified in research studies for their potential to reduce GHG emissions from oil sands processes. These classifications include energy management; renewable and low carbon energy sources; carbon capture, utilization, and storage (CCUS); advanced bitumen production techniques; and cogeneration of steam and electricity. Energy management includes all forms of improving existing processes through increasing efficiency, reducing waste, and/or improving process control. Renewable/low carbon energy sources involve replacing an existing process that consumes fossil fuels and emits GHGs with a process that operates on a renewable or low carbon energy source. These energy sources include wind, hydro, solar, nuclear, biomass, and geothermal energy sources. CCUS technologies involve capturing a portion of GHG emissions from a process and storing them permanently in a geological formation. This can involve adding capture and storage systems onto existing processes or replacing existing processes with another technology better suited for capturing GHG emissions. Captured carbon can also be utilized before being stored, thereby providing a potential revenue stream. Advanced bitumen production techniques involve emerging technologies or processes that are significantly different from existing commercial processes. Presently, the focus of this suite of technologies is for in situ SAGD production where alternatives to steam as a mobilizing agent for in situ bitumen are being explored. Finally, the oil sands industry already uses significant levels of cogeneration, but increasing those levels has the potential to reduce GHG emissions further. Further details on the CCUS technologies are included in Chapter 5.

These five areas are the key classifications of technology options identified in this work for reducing GHG emissions in oil sands processes.

1.4 Market penetration, energy, and GHG emission modelling of the oil sands

In order to understand GHG emission levels from the oil sands and the potential for new technologies to reduce those levels, two key topics need to be understood. The first is how quickly new technologies can feasibly enter the market and their costs. In this research, this is considered through market penetration modelling. The second is understanding the energy consumption levels and subsequent GHG emissions from present day processes and the impact of introducing a different technology. In this research, this is considered through energy accounting.

Market penetration modelling seeks to forecast the level of market share a specific technology can gain in a market based on various criteria. Depending on the level of maturity of the technology being considered, different market penetration modelling techniques may be considered. More detailed background on market penetration modelling and the methods applied in this study are given in Chapter 2.

Several methods exist for forecasting industry GHG emissions and determining the impact different technologies can have on industry wide GHG emission levels. This research is a continuation of a previously developed and validated bottom-up energy accounting model (i.e., LEAP Canada Model) that includes the oil sands industry; all end-use technologies and their respective energy intensities and fuel types are accounted for [12]. The technologies considered in this research are developed as scenarios in that model to determine their marginal impacts on GHG emissions in the industry. Energy and GHG modelling in the oil sands and the model used in this study are explained in greater detail in Chapter 3.

1.5 Knowledge gaps

There is no comparative analysis in the literature of GHG reduction opportunities for the oil sands industry based on currently available information. Various kinds of modelling have been conducted to estimate the GHG abatement potential and costs of technologies for the oil sands, but these models do not have clearly defined feasible scenarios that capture those costs and the technical challenges of using them in the context of the oil sands. Nor do any of these studies incorporate market penetration modelling. Most studies do not forecast future GHG abatement potential of technologies at all and those that do forecast GHG abatement are limited by the lack of consideration towards market penetration modelling. Additionally, a wide variety of studies exist that use different methods for estimating technology cost and GHG abatement potential, often making it difficult to compare their results because of differing assumptions about industry growth, expected costs, and policy impacts. There is a need to develop a consistent framework for evaluating the potential of technologies in the oil sands that is transparent and accurate.

Most of the literature on the integration of renewable energy technologies in oil sands processes is focused on either evaluating life cycle energy and GHG emissions performance [22] or assessing the cost of implementation [23] [24]. A number of techno-economic assessments were performed for a wide range of renewable energy technologies: geothermal [25] [26], nuclear energy [27], hydrogen from biomass [28] [29], electrolysis of hydropower [30], electrolysis of wind energy [31] [32], and solar energy for steam production [33]. Studies on GHG emissions and techno-economic assessments provide important insights into the environmental sustainability and economic viability of energy technologies. However, these assessments do not address the wide deployment or GHG mitigation potential of the technologies in a broader context. Both require an investigation of the market penetration potential of the technologies to determine how quickly the options could be implemented.

To the best of the authors' knowledge, the study by Elsholkami et al. is the only one that considers the penetration of multiple renewable energy technologies and their costs and potential to reduce oil sands emissions [34]. The authors developed a linear program to consider several GHG reduction technologies, including some renewable options, that optimized costs for specified GHG reduction targets. The study identified biomass feedstock boilers for steam-assisted gravity drainage (SAGD) and geothermal energy for thermal heat in mining extraction plants as the most promising technologies to integrate but generally found renewable options non-competitive with existing technologies. However, the study did not include biomass pyrolysis, hydro electrolysis, nuclear energy technologies, or hydroelectricity, all of which have been proposed as options for reducing GHG emissions in the oil sands in the techno-economic studies cited above and should be assessed for long-term penetration and GHG emissions mitigation potential. Nor was the impact of Alberta's recent carbon pricing policies, designed to provide cost incentives for the use of low emission technologies, considered in the evaluation of technology cost. Moreover, given the nature of optimization models and their complex algorithms, the results of Elsholkami et al.'s study are not easy to understand. Optimization models are generally used to identify the lowest cost scenario using linear programming given a set of constraints, such as emissions not exceeding a specified limit and meeting a certain product demand. The implicit assumption in these models is that the lowest cost option in each area is always selected, but this is not always true in practice due to the differing circumstances and strategies of the private organizations investing in them [35]. A logistic distribution based on technology cost is often used by analysts to capture a more realistic representation of how new technologies penetrate a market [36], but this approach has yet to be used to evaluate technology adoption in the oil sands. A bottom-up energy accounting model, such as those constructed using the Long-range Energy Alternatives (LEAP) model [37], is a transparent and flexible modelling method that allows non-least-cost scenario analysis, thereby broadening the scope of analysis.

Studies investigating the applicability of CCUS technologies in the Alberta oil sands lack analysis of the long-term GHG emission abatement potential of the technologies. Ordorica-Garcia et al. conducted a study to identify the optimal carbon capture technology for each major oil sands process [38]. This study identified post-combustion capture for surface mines, oxyfuel boilers for in situ mines, and gasified bitumen (pre-combustion capture) for upgrading; however, the study lacked quantitative analysis of performance or cost of any of these options. Olateju and Kumar conducted techno-economic assessments for producing hydrogen from underground coal gasification (UCG) with pre-combustion capture and steam methane reforming (SMR) with post-combustion capture applied to the Alberta context [39]. This study estimated the costs of using carbon capture and storage (CCS) with SMR to be \$2.11-\$2.70/kg H_2 and CCS with UCG to be \$2.41/kg H_2 but did not determine the cost of mitigated GHG emissions or the GHG abatement potential. Verma and Kumar conducted a life cycle assessment of the carbon emissions from UCG with carbon capture in Alberta but did not perform economic analysis [40]. Verma et al. developed the marginal cost of GHG abatement for carbon capture applied to UCG and SMR in the two studies cited above and found that overall cost savings for reduced emissions were possible if the captured CO_2 could be sold to EOR operators and that UCG was the lowest cost mitigation option [41]. The long-term GHG abatement potential of each technology was not discussed in these studies, however. Bolea et al. similarly developed the costs of using oxyfuel boilers, both with natural gas and bitumen as the fuel, and found that bitumen-fueled oxyfuel boilers can be competitive with currently used once-through natural gas boilers [42]. However, this study only considered carbon capture costs, not transportation and storage costs, and did not determine the GHG emission abatement potential of the options considered. Some key limitations in all of these studies are that year-to-year changes in operation costs based on expected changes to fuel prices are not accounted for and that a single value for the marginal cost of abatement is given. This is useful for determining the basic competitiveness of these technologies with what is currently used but does not allow for cumulative abatement potential to be calculated over a long-term evaluation period.

Currently, the literature does not include analysis of the long-term GHG mitigation potential of using emerging in situ technologies and processes compared to traditional SAGD methods. Critical review has suggested that the steam/solvent hybrid methods have the greatest opportunity for success, based on literature results [43], but no quantified analysis of how much more successful nor the time period required has been conducted. The methods have been qualitatively compared, and basic energy efficiency ranges and water uses for each option have been reported [44], but the studies lacked any production cost analysis. Finally, the expected costs, productivity, and emissions of these processes based on the currently available data have been studied and compared to traditional SAGD [45], but no analysis of long-term GHG mitigation potential was conducted.

Several studies have been conducted to assess the potential for cogeneration plants to reduce GHG emissions in Alberta. These studies have generally concluded that cogeneration is a cost-effective way of reducing GHG emissions when replacing coal power, but there has been little analysis of the long-term abatement potential of these plants. Studies show that it is cost effective to incorporate cogeneration into SAGD facilities [46] and that the resulting power generation reduces the levelized cost of electricity and GHG emissions while coal power plants are being phased out in Alberta [47]. Cogeneration is identified as a near-term option for lowering Alberta's electricity-based GHG emissions, and regulatory frameworks should encourage their development while high emission coal power is still a significant factor [48]. The SAGD subsector has been identified as the key area for this expansion to occur, with analysis suggesting the high penetration of cogeneration there could reduce Alberta's GHG emissions from 13 to 26% in 2030 [49]. Despite these advantages, there are few studies that assess the longer range impacts of cogeneration penetration after coal has been phased out of Alberta power generation, currently planned for 2030 [50]. Cogeneration projects are typically evaluated on at least a 20-year life span, as Doluweera et al. have noted [48], yet the impact of operating these facilities after grid emissions have reduced has not been assessed.

Further research into the long-term GHG abatement potential and marginal costs of technologies in the identified classes is needed. An understanding of the impact of policy decisions, including carbon pricing and GHG emission caps, on the feasibility of these technologies is also currently lacking in the literature. For many of the identified technologies, there is enough data available to model the long-term potential of their application in the oil sands, but a comprehensive study comparing all these options using a consistent approach has not been completed.

1.6 Objectives of research

The primary purpose of this research is to investigate the long-term GHG emission abatement potential and associated marginal GHG abatement costs of integrating the 5 identified classes of technologies into the oil sands. The results will ultimately provide decision-makers in industry and government with GHG emission reduction potentials and costs for renewable technologies over the next 30+ years. These contributions are achieved by completing the following specific objectives:

- Review existing technologies under the 5 identified technology classes that could be incorporated into oil sands production while reducing GHG emissions.
- Create feasible technology scenarios considering realistic applications of those technologies in Alberta, their lifetime costs, and their energy requirements.
- Develop market penetration models to determine the rate at which each technology could feasibly enter the market.
- Integrate bottom-up energy modelling with the market penetration results to determine each technology's long-term economic performance and GHG mitigation potential under different carbon pricing policies.
- Compare GHG mitigation potential and marginal abatement costs of individual technologies and classes of technologies.

Once these objectives are met, the major technology options for reducing GHG emissions from the major Canadian industry of bitumen production from oil sands will be compared and a model that offers consistent and reliable analysis will be constructed. The model can easily be updated as the industry and technologies evolve and is transparent with clear connections between results and input data making it a valuable long-range planning tool.

1.7 Limitations

The methods used in this study are limited to examining technologies with developed cost and performance data specific to operations in bitumen production concept. There are many technologies that have lower GHG emission factors than those used currently in oil sands processes; however, they must be cost-effective for industry to use them. Detailed techno-economic assessments are required to understand these costs, and these have been conducted for many of the technologies that industry stakeholders have identified as hopeful GHG emission management options. However, there are other emerging technologies for which these types of studies do not yet exist and therefore they could not be included in this work. With further research into their costs they could be incorporated into this study; however, at the time of writing these were not available. These technologies are listed in the background sections of the chapters below.

The modelling methods are also limited by the unpredictability of technological advancement. Long-range forecasting requires assumptions to be made about technology performance over time and those assumptions can only be based on the current state of knowledge about that technology. The challenge here is that technologies in early stages of development typically advance in unpredictable breakthroughs that involve sharp increases in performance based on new knowledge [51]. Due to the unpredictability of these advances, technologies in this study are modeled based on their currently understood performance. This makes it imperative that the model is updated as technologies advance for continued accuracy.

A final limitation is from the carbon pricing evaluation. Currently, carbon credits from technologies operating under the emission benchmarks are traded at some value below the taxation rate depending on their availability in the industry. Data is not available for determining the average value of these credits. This study assumes that carbon credits are traded at 85% of the taxation value, and sensitivity analysis is conducted in each section to assess the impact of changes to that value.

1.8 Organization of thesis

This thesis has eight chapters. Chapter 1 introduces the background of GHG emission reduction in the oil sands, discusses current knowledge gaps, and outlines the scope of this work. Chapter 2 presents a background and explanation of market penetration of technologies' modelling and how it was applied to the Alberta oil sands in this work. Chapter 3 presents a background and explanation of energy modelling and the method used in this study to determine energy use and GHG emissions from the Alberta oil sands and GHG abatement potential of scenarios. The remaining chapters discuss specific technology options for the oil sands organized in terms of the technology classifications outlined in Section 1.3 above, with the exception of energy efficiency options as they have already been evaluated with a similar method earlier. Chapter 4 evaluates renewable and low carbon energy options, Chapter 5 evaluates CCUS options, Chapter 6 provides a preliminary look at advanced bitumen production techniques, and Chapter 7 evaluates cogeneration opportunities. Chapter 8 provides the conclusions for the work and summarizes the results of Chapters 4 through 7. Chapters 4, 5, and 7 have been prepared as standalone papers for submission to scientific journals and therefore repeat some information presented in Chapter 1 – Introduction, Chapter 2 – Market penetration modelling of technologies for the Alberta oil sands, Chapter 3 – Modelling energy in the Alberta oil sands, and Chapter 8 – Conclusions. Throughout, figures, tables, and equations are numbered according to the chapter in which they are found and the sequential order in which they occur in the chapter, separated by a hyphen. The Appendix contains additional data used in the study including all formula input data and results as required.

2 Market penetration modelling of technologies for the Alberta oil sands

2.1 Background

In order to determine the GHG abatement potential of a new low-emission technology over a period of time, it is necessary to predict how quickly that technology can displace what is currently being used. The aim of market penetration modelling is to predict the rate of market share changes for new technologies. Market penetration models can be classified into six categories: subjective estimation, historical analogy, cost-based, diffusion, time-series, and econometric [52]. Subjective estimation models gather expert opinions and compare the associated data to determine expected trends and are useful for new technologies or when data is limited. Historical analogy models seek to identify mature technologies and develop a model for a similar new technology, with the assumption that it follows a comparable pattern. Cost models use the expected costs of the emerging technology and the technologies it would replace to estimate the adoption rate. Diffusion models impose a sigmoid curve on adoption to show typical market trends in which adoption starts slowly, hits a peak adoption rate, then slows as the market becomes saturated. Time-series models use the emerging technology's historical data to infer how it will continue to be adopted. Finally, econometric models seek to identify statistically significant factors in the overall market to model their impact on the rate at which a technology will be adopted [53]. An overview of optimal times to use each technique depending on data availability and technology maturity is shown in Figure 2-1.

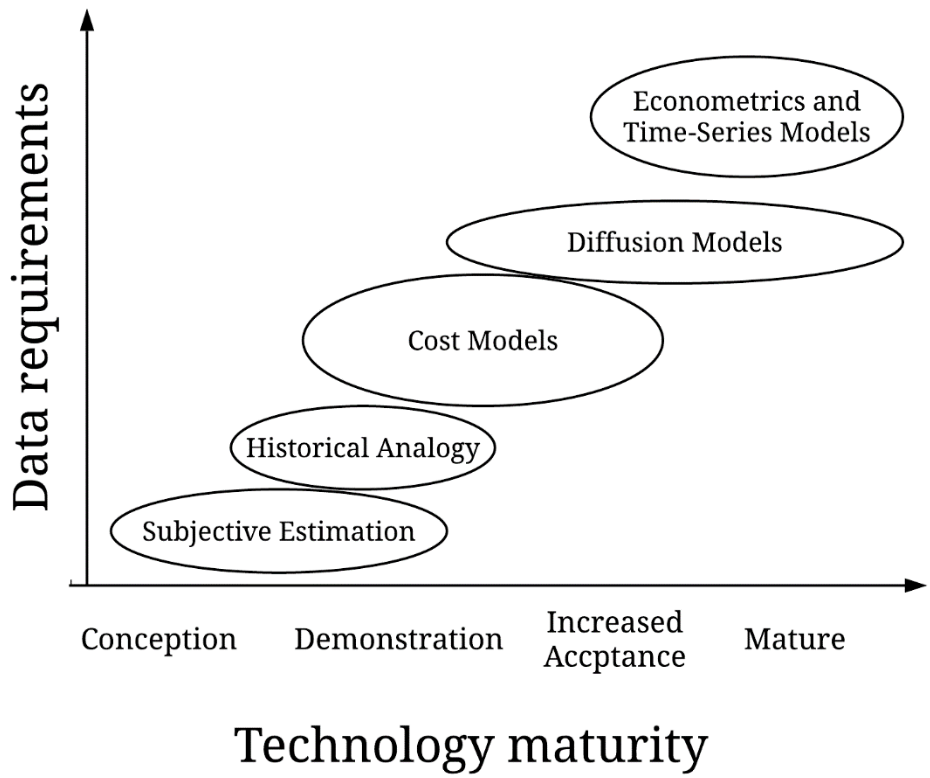


Figure 2-1: Overview of acceptable market penetration modelling techniques given technology maturity and data availability. Adapted from Packey [52].

The types of market penetration models that can be used for oil sands technologies are somewhat limited due the specialized nature of the industry and the unique ways it has developed. It is difficult to find historical analogs to emerging oil sands technologies due to the amount of change the industry has gone through in recent decades, mainly because production has become largely in situ-based rather than the previously dominant surface mining. Also, most technologies are emerging and there is insufficient historical data to develop time-series models.

Market penetration methods applied to the oil sands are mostly subjective estimation or simple cost methods. Subjective estimation studies use expert opinion to determine the timelines prospective technologies will penetrate the market. Suncor Energy and Jacobs Consultancy performed a large-scale study identifying the GHG emission abatement potential of a large number of technologies [54]. Timelines for technology penetration were not quantified exactly, rather the authors categorized technology implementation as an estimated range of time in years before the technology impact could be realized. Similarly, Sleep et al. and McKellar et al. gathered opinions from industry experts about expectations of future technology use and ways to reduce emissions in the industry [55] [56]. Sleep et al. found that experts expect only modest GHG emission reductions and that these reductions would come from using emerging in situ extraction techniques [55]. McKellar et al. found that no significant GHG emission reductions were expected without more stringent emission reduction policies [56]. The Council of Canadian Academies studied each major sector in the industry and found that solvent-based extraction for in situ production, Carbon capture and storage (CCS) for upgrading, and improved mining equipment for surface mining offered the greatest potential, but the council only considered the market penetration of the technologies qualitatively [44]. The model constructed by Elshokalmi et al. is closest to a simple cost model when evaluated against the options in Figure 2-1, in that it optimizes technology penetration for a minimum cost solution, but this approach assumes that the optimal amount of technology usage can be introduced immediately and that the cheapest technology is always successful; it does not include any diffusion modelling principles [34]. Market research shows that more factors than cost are used to make technology decisions and technology uptake usually follows a logistic curve [57]. There are no studies that use quantified cost and diffusion market penetration models to forecast the adoption rate of emerging oil sands technologies.

The purpose of this chapter is to apply a hybrid cost and diffusion market penetration model to emerging oil sands technologies. This will address the research gap in quantifiable market penetration studies of oil sands. The scenarios developed for the model take into account detailed techno-economic data about the technologies considered, ensuring that the modelled costs reflect the expected costs of using those technologies in Alberta for a specific oil sands process. The model output provides expected market shares that can be achieved by each technology through the evaluation period.

2.2 Methods

2.2.1 Scenario development

Scenarios are developed based on the applicability of technologies to oil sands processes in Alberta and the availability of cost and emission data.

2.2.2 Lifetime cost analysis

The selected technologies are first evaluated to determine their market penetration. The economic evaluation of each scenario is conducted using the same key parameters for both the reference and new technology scenarios. This includes converting costs to present values and using and selecting an internal rate of return (IRR) for the analysis. Technology lifetime is determined for each technology based on expected performance. The equations used in the cost penetration calculation have been developed for the energy industry to evaluate climate policy decisions using annualized costs [57]. The annualized cost of each technology includes capital costs, operating expenses, carbon costs, and energy costs and is shown in Equation 2-1 [35].

$$\mathrm{LCC_j} = \left(\mathrm{CC_j} \times \frac{\mathrm{i}}{1-(1+\mathrm{i})^{-\mathrm{n}}}\right) + \mathrm{OC_j} + \mathrm{ECC_j} + \mathrm{EC_j} \qquad (2\text{-}1)$$

where:

$LCC_j = Annualized\ lifetime\ cost\ of\ technology\ j$

$CC_j = Overnight\ capital\ cost\ of\ technology\ j$

$i = Interest\ rate$

$n = Technology\ lifetime$

$OC_j = Annual\ operation\ and\ maintenance\ costs\ of technology\ j$

$ECC_j = Annual\ emitted\ carbon\ cost\ for\ technology\ j$

$EC_j = Annual\ energy\ cost\ for\ technology\ j$

In order to incorporate the GHG emission costs and the most recent legislation, Equation 2-2 is used to calculate the annual GHG emitted carbon cost:

$$\mathrm{ECC_j} = BE_M \times EF_j \tag{2-2}$$

where:

$BE_M = Annual\ benchmark\ emission\ factor\ for\ sector\ M$

$EF_j = Emission\ factor\ for\ technology\ j$

2.2.3 Market share calculation

The results from the annualized lifetime costs are then used in the market share algorithm shown in Equation 2-3, which simulates technology competition [57]. Equation 2-3 represents a diffusion penetration model based on a logit curve:

$$\mathrm{MS_j} = \frac{\mathrm{LCC_j^{-v}}}{\sum_{\mathrm{j=1}}^{\mathrm{k}} \mathrm{LCC_j^{-v}}} \tag{2-3}$$

where:

$MS_j = Market\ share\ of\ technology\ j\ for\ the\ examined\ year$

$v = Cost\ variance\ parameter$

$k = Number\ of\ competing\ technologies\ in\ the\ examined\ sector$

The variance parameter determines the slope of the curve; a high value ensures the lowest cost technology receives nearly all the market share. A model such as a cost-based linear optimization would embrace this; the lowest cost technology receives all the market share. Market research suggests that this is not the case, however, and other reasons such as long-term technology promise, market forecasts, and business strategy can result in higher cost options being selected. To account for this, a lower value cost variance is used to better reflect market behavior. Nyboer determined the most appropriate values for the cost variance parameter for the energy industry to be in the range of 6 to 10 [35]. In this research, a value of 8 is used and sensitivity analysis is conducted to determine the effect on the results over this value. The resulting distribution generated using a cost variance parameter of 8 for a two-technology scenario is shown in Figure 2-2 as an example. In the two-technology example, the results show that if technology 1 were 25% cheaper than technology 2, the first technology would gain 94% of the market. Conversely, if technology 1 was 10% more expensive than technology 2 it would only gain 32% of the market share. Using this cost variance parameter value, we determined the market share of each technology on an annual basis based on the amount of new product expected that year and the percent market share determined through the penetration model. Annual subsector production growth quantities used in the model are taken from the production forecasts published by the National Energy Board (NEB) [13] and the Alberta Energy Regulator (AER) [20]. These production forecasts for the surface mining, in situ, and upgrading subsectors are shown in Figure 2-3. Equipment retirement is not considered due to the short evaluation period and lack of available data, nor are retrofits considered because work by Brandt et al. concluded that emission reduction would not be significant [58].

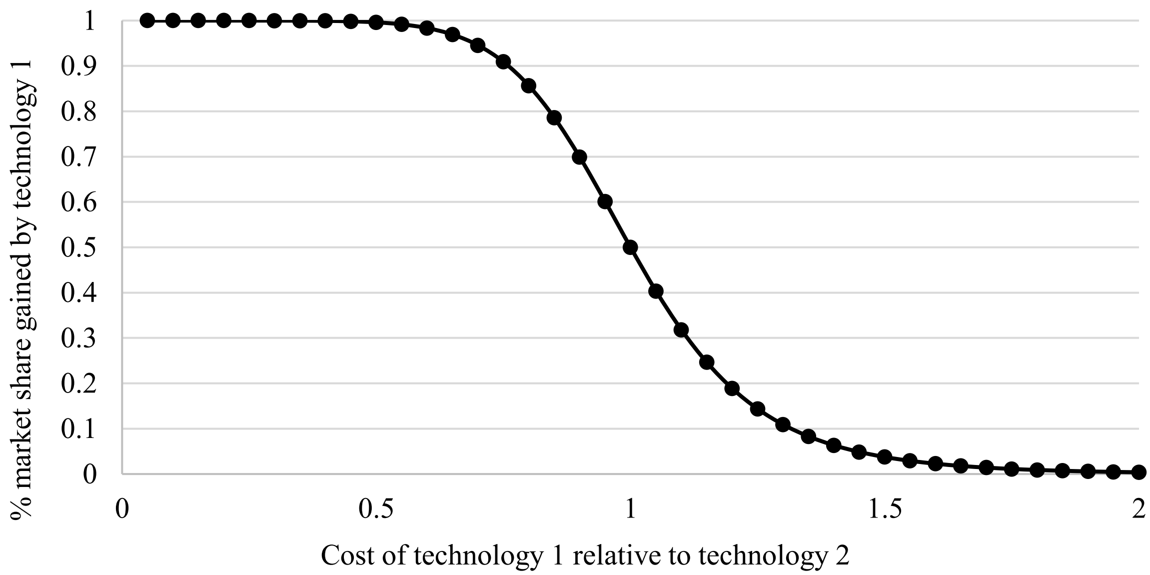


Figure 2-2: Example of market share results for a two-technology scenario

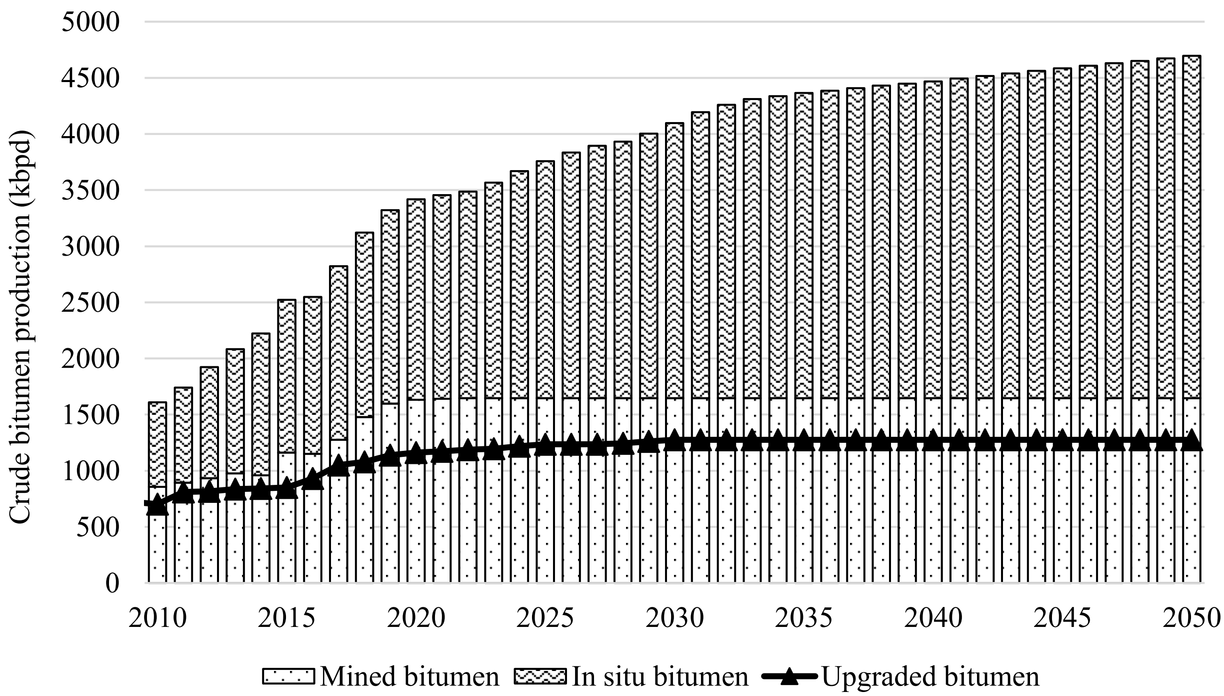


Figure 2-3: Production forecast for oil sands bitumen

2.3 Results and Discussion

2.3.1 Maximum penetration potential

Using the production forecasts, we determined the maximum penetration opportunity for technologies in each subsector; the results are shown in Figure 2-4. The upgrading subsector is forecasted to have an 18% increase in capacity, all of it between 2020 and 2031. The in situ CSS subsector is currently forecasted to see no growth. Hence this study concluded that no abatement potential is possible with technologies meant to compete with the CSS process; however, some were evaluated to determine comparative costs. This research is still valuable as further analysis could be done to investigate the possibility of retrofitting existing facilities or, if market conditions change in a way that justifies further growth in the CSS subsector. The in situ SAGD subsector showed the most significant growth potential of any subsector considered, at a forecasted 58% capacity increase by 2050. Expected growth is relatively consistent in this subsector through the entire evaluation period. The surface mining subsector is expected to grow by 23% in production capacity, with all the expected growth occurring in the next 5 years. Electricity demand is driven by all the subsectors and is considered separately in order to evaluate the specific technologies available for dedicated electricity production. Electricity demand is forecasted to increase by 35% by 2050, with the most significant increases occurring before 2026.

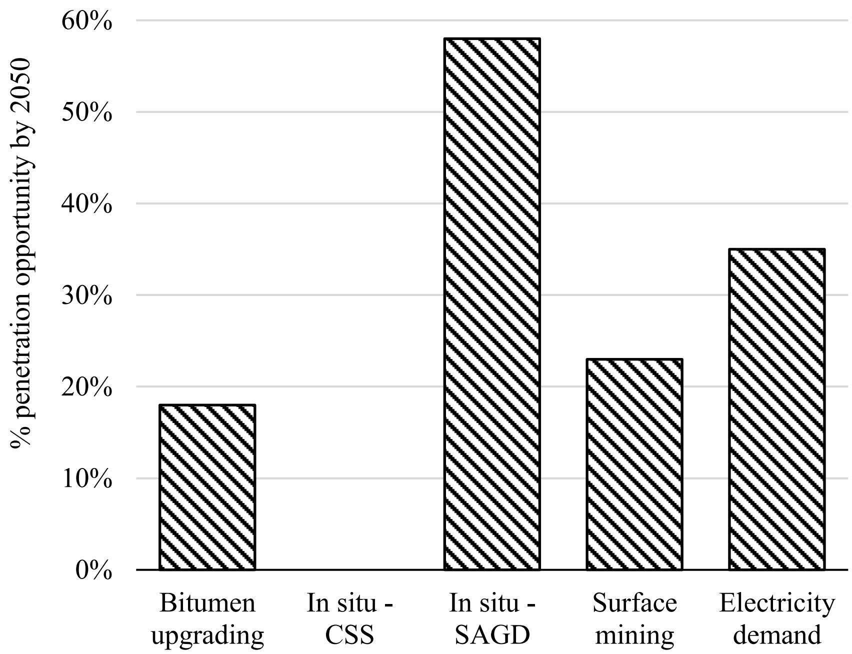


Figure 2-4: Maximum 2050 penetration potential by subsector

2.3.2 Further results in chapters below

Each of the subsequent chapters evaluates different classes of technology options in feasible scenarios specific to the identified subsectors. The methods presented in this chapter are applied to evaluate those technologies, and market penetration results are presented in those chapters. Each scenario is compared to the maximum available penetration levels shown in Figure 2-4.

2.4 Conclusions

This chapter presents the framework for the technology market penetration model appropriate for the status of emerging oil sands technologies that was applied in this research. The model is a hybrid cost and diffusion model that compares technologies based solely on their forecasted costs and assigns an annual market share to each scenario based on a logit distribution reflecting research into technology adoption in the energy industry. The maximum penetration potential for each oil sands subsector considered over the evaluation period was also calculated to give an understanding of the potential for technologies in each subsector to break into the market. Market penetration results are presented for specific technologies in Chapters 4 through 7.

3 Modelling energy in the Alberta oil sands using LEAP

3.1 Introduction

The energy intensity and subsequent GHG emissions related to producing bitumen varies substantially depending on the production method. Current technologies used in oil sands processes are mainly powered by natural gas, electricity, or diesel fuel. Natural gas is used extensively for process heat in surface mining, steam generation for in situ processes, and steam methane reforming in upgrading. Electricity is used for plant operation and equipment in all production methods as well as for some mobile mining equipment in surface mining. Electricity for oil sands operations is either generated on-site in natural gas cogeneration plants or sourced from the grid. Diesel fuel is used for mobile mining equipment.

Several models and methods have been developed to estimate energy consumption and GHG emissions in oil sands processes; however, they only consider specific production paths rather than the industry as a whole. Ordorica-Garcia et al. developed a process-level mathematical model for determining energy consumption and GHG for mined bitumen upgraded to SCO and SAGD bitumen and found emission levels of 0.08 tCO_2e - 0.087 tCO_2e/bbl SCO from surface mines and 0.083 tCO_2e/bbl bitumen from SAGD [18]. Nimana et al. developed a spreadsheet-based model using fundamental engineering principles to determine energy consumption and GHG emissions in surface mining and SAGD applications [16]. The results from this model show that energy consumption is predominantly natural gas and ranges from 52.7 MJ - 86.4 MJ of natural gas/GJ of bitumen in surface mining and 123 MJ - 462.7 MJ of natural gas/GJ of bitumen. The resulting GHG emissions from the processes ranged from 4.4 gCO_2e - 7.4 gCO_2e/MJ of bitumen in surface mining and 8.0 gCO_2e – 34.0 gCO_2e/MJ of bitumen in SAGD. Lazzaroni et al. similarly developed a model based on engineering principles, but for a specific production path (SAGD extraction combined with delayed coking upgrading) [17]. The results predict energy consumption of 262.5 MJ - 368.5 MJ/GJ of SCO and GHG emissions of 14.2 gCO_2e - 19.8 gCO_2e/MJ of SCO, finding, as the other models do, that a majority of emissions (~60%) are from natural gas combustion in SAGD processes. While these results are useful for the specific processes investigated, the entire industry needs to be evaluated to properly understand the options available to them for reducing GHG emissions.

There are models that provide industry-wide data on energy consumption and GHG emissions; however, the available options lack both transparency and the ability to model alternative scenarios. Bergerson et al. developed a process-based life cycle analysis (LCA) model for energy consumption and GHG emissions from oil sands production using actual operating data of oil sands projects [59]. The input data from operations used in this model is confidential, however, making the results specific to the projects from which the data was taken and the model information not fully transparent. Brandt reviewed the different LCA models used for oil sands emissions [60] and concluded that GHGenius [61] is the best choice for determining accurate GHG results; however, process-level energy consumption data is not available in it, thus limiting its use for examining alternative scenarios.

In addition, none of the reviewed studies forecast energy needs and expected emissions for long-range planning purposes or compare the results to existing carbon emission legislation. In summary, there are several knowledge gaps in assessing energy consumption and GHG emissions in the Alberta oil sands industry including the lack of a comprehensive model with transparent process-level energy consumption data and a model that can be used to assess alternative technology options in long-range scenarios.

This section of research addresses these gaps by:

- Co-developing a bottom-up energy accounting model specific to the Alberta oil sands with transparent data sources and input values that allows alternative scenarios to be constructed and compared; and
- Using the available market data to forecast energy requirements and GHG emissions from the oil sands industry and comparing the results to existing carbon emission legislation.

3.2 Modelling methods using LEAP

The Long-range Energy Alternatives Planning (LEAP) software is an energy accounting tool developed by the Stockholm Environment Institute for modelling energy systems from energy extraction to end use [37]. It is designed for bottom-up models, in which a demand module is constructed with all the energy-consuming technologies accounted for by the form of energy they consume and the rate they consume it. The demand module receives energy from the transformation module, which accounts for energy conversion processes, imports of energy shortfalls, exports of energy excess, and all the associated losses with those activities. Finally, each fuel is given an emission factor, either through the Technology and Environment Database (TED) built into LEAP or defined by the user, which allows GHG emissions to be determined. TED fuel emission factors are based on literature values, such as those provided in the IPCC 5th Assessment Report [1]. A reference scenario is constructed, typically to represent the current state of the modelled area, then alternative scenarios that incorporate other technologies can be modelled and their results compared to the reference scenario outputs. The LEAP model has been used to model entire nations' energy systems, such as Canada's [62], or individual industries, i.e., the Canadian cement and the chemical industries [63]. Therefore, it is a suitable tool for modelling the energy and GHG emissions from an energy-intensive industry such as the Alberta oil sands.

This study is a continuation of previous work that modelled the Alberta mining industry, including the oil sands [12]. The oil sands portion of this model was validated by Katta et al. with historical data and the results are within 0.4% of actual reported energy consumption and within 4% of reported GHG emissions [12, 64]. For the work completed in this thesis, the oil sands area was isolated to create a standalone model (LEAP-Oil sands) and updated using the latest demand projections from the National Energy Board (NEB) [13] and the Alberta Energy Regulator (AER) [20]. The demand module covers the technologies used to produce and upgrade bitumen through a variety of processes. The transformation module accounts for the main electricity generation options for oil sands producers.

3.2.1 Demand module and energy demand tree

The demand module is broken into the major subsectors of oil sands production (shown in Figure 3-1) and is explained in further detail below. Each subsector has unique processes that offer potential for replacement technologies with lower GHG emissions and that are forecasted to grow at different rates. This structure allows for scenario development and results separation that account for those realities. Each subsector's energy-consuming technologies are identified in greater detail below, and the energy intensities of each technology can be found in Katta et al.'s study [12].

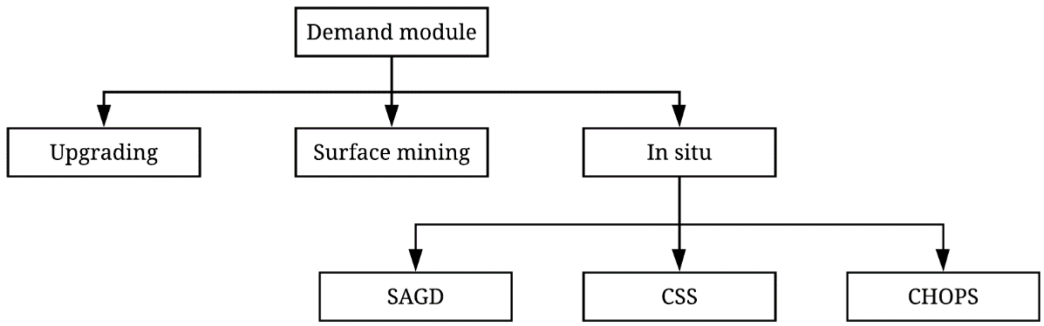


Figure 3-1: LEAP-Oil sands demand module structure

A portion of the crude bitumen produced is sent to upgraders to be processed into synthetic crude oil (SCO). There are two main processes currently used for upgrading; the LC fining and hydrotreatment process and the coking and hydrotreatment process. The energy-consuming technologies for each process are listed in Table 3-1. A combination of natural gas, fuel oil, and electricity provide energy to these upgrading technologies, with the most energy intensive process being hydrogen generation using a steam methane reforming process.

Table 3-1: LEAP-Oil sands end-use technologies for the upgrading subsector

Subsector	**Upgrading**	
Process	LC fining & hydrotreatment	Coking & hydrotreatment
Technology	Distillation	Crude distillation
	Residue hydroconversion with integrated hydrotreatment	Vacuum distillation
	Sulphur recovery	Gasoil hydrotreater
	Hydrogen generation	Other hydrotreatment
	Solvent deasphalting	Hydrogen generation
	Steam generation	Coking unit
	Other utilities	Steam generation
		Sulphur plant
		Other utilities

Surface mining consists of operations that use traditional shovel and bucket mining processes to produce crude bitumen from near surface reservoirs. Table 3-2 outlines the energy-consuming technologies in this subsector that consume a combination of natural gas, diesel fuel, and electricity.

Table 3-2: LEAP-Oil sands end use technologies for the surface mining subsector

Subsector	Surface mining
Technology	Pumping (steam, bitumen, and tailings)
	Conveyor belts for slurry transport
	Power shovels
	Crushing
	Mixing
	Flotation
	Air compression
	Steam generation
	Raw bitumen transport

The CSS subsector consists of pumping steam into a deeper reservoir intermittently in order to reduce the viscosity of the in situ bitumen and allow it to be pumped to surface through the same well. The technologies used in this process are outlined in Table 3-3 and use a combination of natural gas, produced gas, and electricity for energy.

Table 3-3: LEAP-Oil sands end use technologies for the CSS subsector

Subsector	Cyclic steam stimulation
Technology	Steam pumps
	Compressors
	Mixers
	Process heat

The SAGD subsector consists of drilling two parallel lines (one above the other) through a deeper reservoir, then pumping steam into the reservoir through the top line resulting in the bitumen being mobilized and draining into perforated piping in the lower line. This mobilized bitumen is then pumped to surface. The technologies used in this process are identical to CSS; however, their energy intensity varies and so they are separated in the model. A similar situation is modelled for the cold heavy oil production with sand (CHOPS) subsector, where end-use technologies are the same, but energy intensities vary. The SAGD subsector demand tree is shown in Table 3-4 and the CHOPS subsector demand tree is shown in Table 3-5.

Table 3-4: LEAP-Oil sands end-use technologies for the SAGD subsector

Subsector	Steam assisted gravity drainage
Technology	Steam pumps Compressors Mixers Process heat

Table 3-5: LEAP-Oil sands end-use technologies for the CHOPS subsector

Subsector	Cold heavy oil production with sand
Technology	Steam pumps Compressors Mixers Process heat

3.2.2 Transformation module

The LEAP-Oil sands transformation module only contains electricity generation technologies in order to account for the GHG emissions directly associated with oil sands production. The energy and GHG emissions associated with fuels supplied to the oil sands (natural gas and diesel) are accounted for in their own production sectors, and fuels generated in the end-use process (produced gas and fuel oil) have their production emissions accounted for in the demand module. The two processes modelled for electricity generation are shown in Table 3-6. While electricity usage in oil sands production is complex, this model assumes merit order distribution, wherein cogeneration capacity is used first and any shortfall is supplied by the Alberta grid. Capacities and the associated GHG emission factors for each process are outlined by Katta et al. [12].

Table 3-6: LEAP-Oil sands transformation module technologies

Module	Transformation - Electricity generation
Technology	Cogeneration AB grid mix

3.3 Results and discussion

The reference scenario was run from 2009 to 2050 to determine expected energy requirements and subsequent GHG emissions from oil sands processes.

3.3.1 Reference case energy use

The energy demand from oil sands subsectors will vary over the years depending on many factors including industry growth, fuel prices, and technology breakthroughs. This can be seen in Figure 3-2, which shows the total energy demand from oil sands processes broken down by subsector from 2009 to 2050. In 2009, from the LEAP-Oil sands model, total energy demand was 665 PJ, of which SAGD contributed 18%. By 2018, energy demand had nearly doubled to 1296 PJ and SAGD accounted for 42% of demand. Further, forecasts imply that if current technologies continue to be used as they are now, energy demand will be 2025 PJ by 2050, 58% from SAGD. Upgrading and surface mining also contribute significantly to the energy demand projections and are expected to contribute 23% and 10% of energy demand in 2050, respectively, but to grow at lower rates (1.1% and 1.0% from 2019 to 2050, respectively).

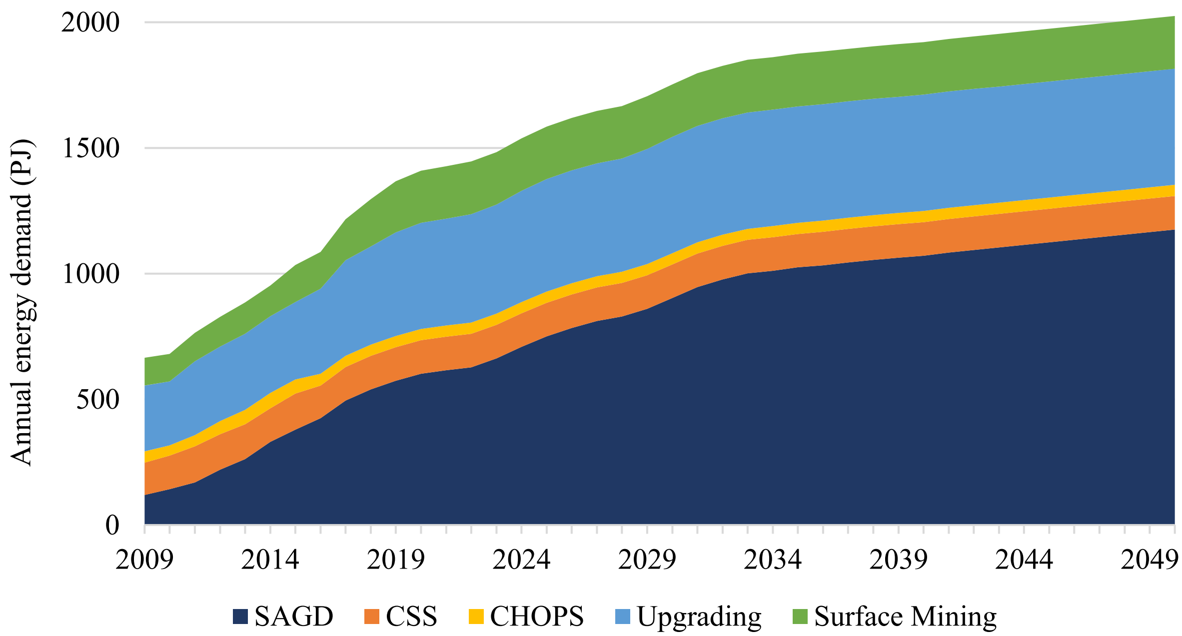


Figure 3-2: Annual energy demand by subsector

Viewing the same energy demand results by fuel type instead of subsector helps give an understanding of how this energy demand will need to be met. These results are shown in Figure 3-3. The results show that natural gas has been and is expected to continue to be the key source of energy for the oil sands industry if the current suite of technologies continues to be used. Natural gas contributed 55% of energy supply in 2009 and expected to contribute 66% of energy supply in 2050 in the business-as-usual scenario.

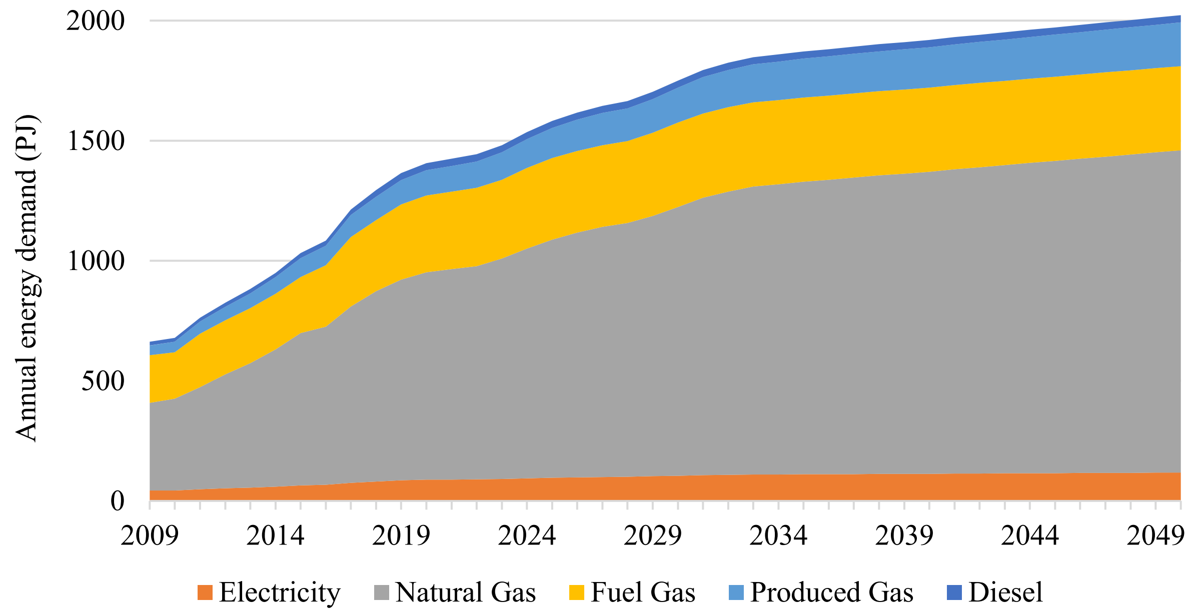


Figure 3-3: Annual energy demand by fuel source

Electricity demand is met through a combination of cogeneration plants and Alberta grid power. Electricity demand is expected to increase from 44 PJ in 2009 to 118 PJ in 2050. An increasing share of electricity demand is expected to need to be met through Alberta grid electricity, where 11% was supplied from the grid in 2009 and 27% is expected in 2050. Expected electricity demand for the oil sands industry is shown in Figure 3-4.

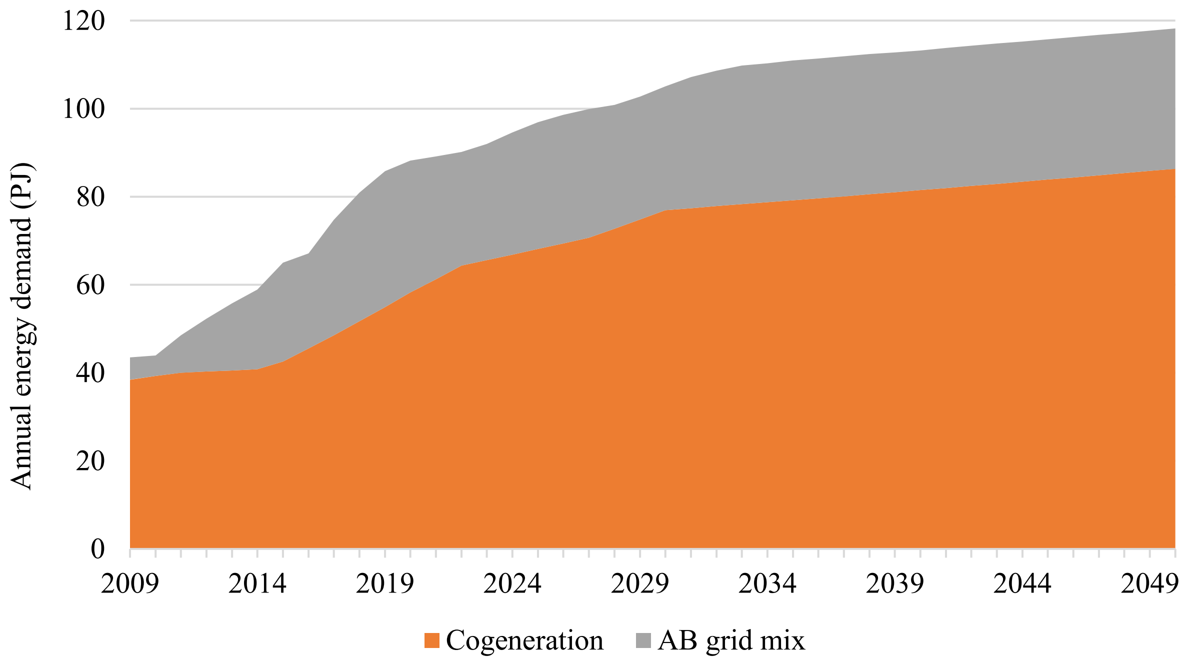


Figure 3-4: Annual electrical energy output from the transformation sector by energy source

3.3.2 Reference case emissions

The LEAP-Oil sands results for GHG emissions in the BAU scenario were also determined, and the annual GHG emissions by subsector are shown in Figure 3-5. 2009 GHG emission levels were 41 Mt, with 37% coming from the upgrading subsector, 16% from CSS, and 15% from SAGD. By 2018, total emissions were 81 Mt, with 35% from SAGD, 28% from upgrading, and 14% from electricity generation. These results show the shift in production that occurred in that time period, with fewer upgraders constructed and a large growth in SAGD. 2050 emissions results predict 120 Mt of industry-wide emissions with 52% from SAGD, 23% from upgrading, and 9% from electricity generation. Again, these results reflect the expectation of continued growth in the SAGD subsector and minor growth in the upgrading subsector.

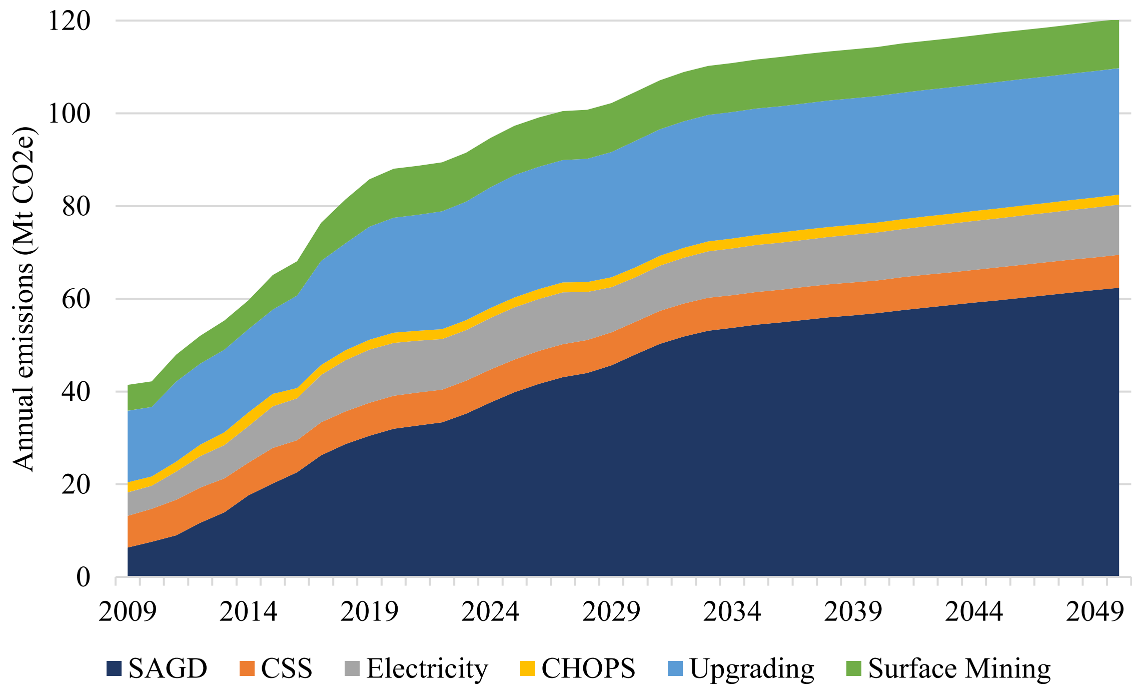


Figure 3-5: Annual emissions by subsector

Recent provincial policy has led to a 100 Mt GHG emissions cap on the oil sands industry, with some sector's emissions subject to exclusions [9]. Excluded GHG emissions are from several areas, the most significant being GHG emissions from cogenerated electricity and upgraders built or expanded after 2015. Figure 3-6 shows the industry GHG emissions, including exclusions, again broken down by subsector. The LEAP-Oil sands model results show that in the BAU scenario, the GHG emissions cap would be exceeded in 2041.

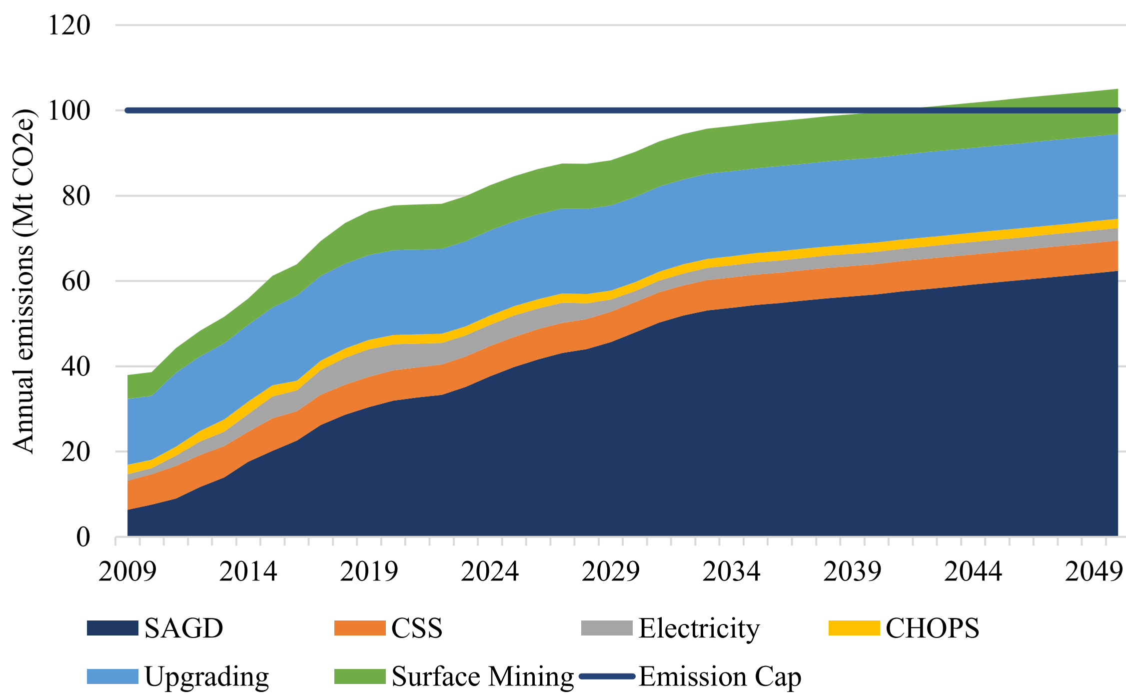


Figure 3-6: Annual emissions cap relevant emissions by subsector

3.3.3 Further results in chapters below

These results for the BAU scenario in the LEAP-Oil sands model are used to determine GHG abatement potential and marginal costs for alternative technology scenarios developed in the chapters below. The alternative technologies replace specific end-use technologies in the demand module of the model at a rate determined by the market penetration model and results can be compared back to the GHG emissions provided above.

3.4 Conclusion

In summary, previous research that developed a bottom-up energy accounting model of the Alberta oil sands industry was continued and a technology-level model, LEAP-Oil sands, capable of forecasting Alberta oil sands' energy requirements and GHG emissions from 2009 to 2050, was constructed. The model structure is described, and energy requirements by oil sands subsector and fuel source are determined for the evaluation period. The SAGD subsector is expected to drive energy demand, and the most significant energy source both in growth in use and quantity used is natural gas. Additionally, GHG emissions were determined throughout the evaluation period by subsector; the SAGD subsector drives emissions' growth as well. Finally, emissions results were compared to the recently legislated emissions cap, and it was determined that the BAU case is expected to exceed the cap in 2041. The model can be used to see the impact on energy requirements and GHG emissions through the development of scenarios that replace currently used technologies with other options or specify energy intensity reductions based on technological improvements.

4 Greenhouse gas emission abatement potential and associated costs of integrating renewable and low carbon energy technologies into the Canadian oil sands[1]

4.1 Introduction

Economic growth and environmental sustainability are critical concerns of any society. A key aspect of economic growth is access to affordable and reliable energy sources. Globally in 2017, an estimated 81% of energy consumption is sourced from fossil fuels in the form of coal, natural gas, or oil [65] showing that these are currently the most accessible energy sources in many parts of the world. Projections suggest that global energy demand will continue to grow as well, with estimates of 25% energy demand growth from 2018-2040 [66]. Global greenhouse gas (GHG) emission are also a growing environmental concern, most recently acknowledged by many countries in the Paris Agreement [3]. Analysis of global GHG emissions shows that at least 65% are from fossil fuel consumption and industrial processes [1]. Due to the competing demands of meeting global energy needs and addressing urgent environmental issues there is a clear global need to develop ways of producing energy with lower GHG emissions.

Canada's oil reserves rank third globally, and 97% of them are found in Alberta's (a western province in Canada) oil sands deposits [17]. Moreover, current hydrocarbon production in Canada is dominated by oil sands resources. In 2016 crude bitumen production averaged 2.4 million bbl/day; this represents 62% of Canada's oil production [67] and was a 56% increase from 2010.

[1] A version of this chapter has been submitted for publication, titled: R. Janzen, M. Davis, A. Kumar, "Greenhouse gas emission abatement potential and associated costs of integrating renewable and low carbon energy technologies into the Canadian oil sands," Journal of Cleaner Production (Submitted), 2019.

It is projected to grow to 4.4 million bbl/day by 2035 [13]. The oil sands industry contributed CAD$82.6 billion to the Canadian economy, or roughly 5% of the GDP, in 2016 [21]. In the Canadian province of Alberta, both economic growth and environmental sustainability are significant in the oil sands industry [68] [69].

Oil sands is a productive part of the Canadian economy and are a large contributor to Canada's GHG emissions. Canada has made international commitments to reduce GHG emissions, most recently as part of the Paris Agreement, a global effort to curb emissions and limit global warming to well below 2°C above pre-industrial levels. Bitumen production currently uses emission-intensive processes and, in 2016, accounted for about 10% of Canada's GHG emissions [67]. Governments at federal and provincial levels in Canada have made GHG reduction a priority, with the oil sands identified as a key sector [9] [4]. The Alberta government has capped oil sands emissions at 100 MT/year [9]. Despite these efforts, projections suggest that GHG emissions will continue to increase [70]. Hence, there is a need to develop ways for reduction of GHG emissions from oil sands sector.

Most of the existing literature on the integration of renewable energy technologies in oil sands processes is focused on either evaluating life cycle energy and GHG emissions performance [22] or assessing the cost of implementation [23] [24]. A number of techno-economic assessments were performed for a wide range of renewable energy technologies: geothermal [25] [26], nuclear energy [27], hydrogen from biomass [28] [29], electrolysis of hydropower [30], electrolysis of wind energy [31] [32], and solar energy for steam production [33]. Studies on GHG emissions and techno-economic assessments provide important insights into the environmental sustainability and economic viability of energy technologies. However, these assessments do not address the wide deployment or GHG mitigation potential of the technologies in a broader context. Both require an investigation of the market penetration potential of the technologies to determine how quickly the options could be implemented and what is the extent of potential GHG mitigation through penetration of various renewable energy technologies in the oil sands sector.

An earlier study focused on selected renewable energy technologies as options of GHG mitigation for oil sands using optimization models [34]. However, the study did not include biomass pyrolysis, hydro electrolysis, nuclear energy technologies, or hydroelectricity, all of which are potential options for reducing GHG emissions in the oil sands. These technologies need to be assessed in terms of their long-term penetration and GHG emissions mitigation potentials. There is limited focus on the literature on the assessment of impacts of carbon incentive policies on the use of low emission technologies for oil sands. Optimization models used in an earlier study [26] are generally used to identify the lowest cost scenario using linear programming given a set of constraints, such as emissions not exceeding a specified limit and meeting a certain product demand. The implicit assumption in this model is that the lowest cost option in each area is always selected, but this is not always true in practice due to the differing circumstances and strategies of the private organizations investing in them [35]. A logistic distribution based on technology cost is often used by analysts to capture a more realistic representation of how new technologies penetrate a market [36], but this approach has yet to be used to evaluate technology adoption in the oil sands. A bottom-up energy accounting model, such as those constructed using the Long-range Energy Alternatives (LEAP) model [37], is a transparent and flexible modelling method that allows non-least-cost scenario analysis, thereby broadening the scope of analysis.

LEAP is a bottom-up energy accounting tool; it was used to determine emissions from each technology scenario [37]. The LEAP model is broken into energy demand and transformation modules in which each module is made up of technologies and processes with energy requirements and usage rates. The energy demand module contains all the technologies used in a particular sector. Each technology is defined by the type of energy it consumes and its energy intensity (energy consumed/product mined). Each technology also has a GHG emission intensity that is used to calculate system-wide emissions. Emission factors are user-defined or taken from LEAP's built-in emission factors, which are sourced from the IPCC [1], depending on the fuel. The energy transformation module supplies the energy demand module with the fuels required.

The LEAP model has been used to develop an oil sands specific model (LEAP-Oil Sands) previously, where the authors modeled a reference case for the oil sands and validated the results using historic data to be within 0.4% of actual reported energy consumption values and 4% of reported GHG emissions [12]. Energy intensities for each technology were developed using various publications, industry reports, and projections from the National Energy Board (NEB).

In light of the studies presented above, the knowledge gap the present study addresses is long-term evaluation and comparison of a wide range of renewable energy options for GHG mitigation in the oil sands. This research work makes three unique contributions:

- A novel framework is developed through the integration of a technology penetration model with a bottom-up energy accounting model using LEAP;
- The study evaluates feasible scenarios that incorporate renewable and low carbon technologies into oil sands processes that have not yet been looked into (hydrogen electrolysis using wind and hydro energy, nuclear steam and electricity, solar steam, hydrogen generation from biomass, geothermal process heat, and hydroelectricity) and that can reduce fossil fuel consumption and subsequent GHG emissions;
- The effectiveness of potential carbon incentive regulations to encourage the adoption of renewable and low carbon energy technologies to reduce GHG emissions is determined.

The overall objective of this research is to investigate the GHG emission abatement potential and associated costs of integrating renewable technologies into the oil sands. The results will ultimately provide decision makers in industry and government with emission reduction potentials and costs for renewable technologies over the next 30+ years. These contributions are achieved through the following specific objectives:

- The assessment of 10 low-carbon technologies including their penetration rate over a planning horizon from 2019-2050.
- The development of 30 scenarios across oil sands extraction (cyclic steam stimulation, steam-assisted gravity drainage, and surface mining), upgrading, and electricity generation over a planning horizon of 31 years.
- The estimation of GHG emissions mitigation potential (tonnes of CO_2) and associated cost ($/tonne of CO_2).
- The determination of each technology's long-term economic performance and GHG mitigation potential under different carbon incentive schemes.
- The development of GHG mitigation cost curves for integration or renewable energy technologies in oil sands sector.

4.2 Oil sands background

Oil sands are made up of crude bitumen and other mineral material found in large quantities in northeastern Alberta, Canada. Crude bitumen is a type of heavy crude oil characterized by high viscosity, generally greater than 500 Pa·s; high density, between 970 kg/m^3 and 1015 kg/m^3; and low hydrogen-to-carbon ratios [10]. Crude bitumen from oil sands is produced through surface mining or in situ techniques. Surface mining is used for ores near the surface and is similar to traditional mining, in which ores are dug in open pits and transported with mobile mining equipment to an extraction facility where they are mixed with heated water to separate bitumen from sand. The bitumen is then collected and processed further, and the sand is disposed. In situ techniques are used when the reservoir is 200 m or more underground, and the resources are extracted through pumped wellbores [11]. Various techniques are used for in situ extraction, the most common being SAGD and cyclic steam stimulation (CSS). Both involve injecting steam into the reservoir to heat the bitumen and reduce its viscosity, allowing it to be pumped to the surface. Recent trends have shown growth in the oil sands industry and an increase in the share of in situ methods, especially SAGD, compared to surface mining. In 2010, 53% of bitumen produced (313 million bbl) was from surface mines, and in 2017 this figure dropped to 46%, or 475 million bbl [13]. Once bitumen is produced, it is either upgraded to higher quality synthetic crude oil (SCO) or diluted with lighter hydrocarbons and sold as diluted bitumen (dilbit). Bitumen upgrading has grown in the last decade, though not at the same rate as bitumen production. In 2009, approximately 263 million bbl bitumen was upgraded, or 48% of bitumen production, while in 2017, 384 million bbl was upgraded, or 35% of bitumen production [13, 14].

The energy intensity and subsequent GHG emissions related to producing bitumen differ substantially depending on the production method. Current technologies used in oil sands processes are mainly powered by natural gas, electricity, or diesel fuel. Natural gas is used extensively for process heat in surface mining, steam generation for in situ processes, and for steam methane reforming in upgrading. Electricity is used for plant operation and equipment across all production methods as well as for some mobile mining equipment in surface mining. Electricity for oil sands operations is either generated on site in natural gas cogeneration plants or sourced from the Alberta grid. Diesel fuel is used for mobile mining equipment. Natural gas consumption is considerably higher for in situ techniques, with the average SAGD plant without cogeneration consuming 148 MJ of natural gas per GJ of bitumen produced, while surface mining averages are 74 MJ of natural gas per GJ of bitumen produced [16]. Steam production is responsible for the largest portion of industry emissions – 50% of industry-wide carbon emissions – and steam requirements are expected to be the key determinant of future emissions From 2009 to 2012 industrial natural gas demand increased by 51% in Alberta, where increases in oil sands consumption accounted for 80% of the demand growth [20]. Because of the growth of in situ methods, GHG emissions from oil sands have increased and will continue to grow in business-as-usual (BAU) scenarios.

4.3 Review of renewable and low carbon energy technology options

Studies on renewable energy technologies applicable to the oil sands are reviewed here. Technologies are categorized as biomass feedstock, nuclear, hydro, geothermal, solar, and wind. In addition to the review, the technologies' functions are explained and the level of data currently available is discussed. Additionally, technologies potentially applicable in oil sands processes that could benefit from oil sands-specific studies is discussed briefly. A summary of the reviewed technologies can be found in Table 4-1 below.

4.3.1 Biomass feedstocks

Biomass feedstocks are any plant or algal materials that can be used to produce fuels. Energy sources like these can be regrown in short time spans (unlike fossil fuels) and are therefore viewed as carbon neutral despite the carbon emissions from processing them. Western Canada has significant quantities of forestry and agricultural products that could be used for energy consumption [71], and the Alberta government is actively encouraging the development of bioenergy through the Bioenergy Producer Program [72]. These feedstocks could present a carbon-neutral energy alternative to the natural gas that dominates energy consumption in oil sands processes. There is high demand in the oil sands for hydrogen in bitumen upgrading processes; biomass feedstocks can be used for hydrogen production. Hydrogen for bitumen upgrading is currently produced through steam methane reforming (SMR), which uses natural gas as a feedstock, making prices of hydrogen highly dependent on natural gas markets. Researchers have studied the conversion of whole tree products to hydrogen via thermal gasification and found that hydrogen could be produced and delivered to upgraders at $2.20/kg [28]. That study also investigated the use of forest residues and straw and found that forest residue could be used for hydrogen at $2.19/kg [73]. In yet another study, the researchers investigated the conversion of biomass to bio-oil via fast-pyrolysis (the bio-oil can be used in SMR to produce hydrogen) and found that whole tree feedstocks were optimal and could produce and deliver hydrogen for $2.40/kg [29]. These options all represent opportunities to replace natural gas in the SMR used at bitumen upgrading facilities. Research on improving catalysts for H_2 production from bio-oil [74] indicates continued interest in the processes and the possibility of further reducing production costs. Key challenges in using these technologies are the cost of collecting and transporting biomass feedstock or products [28] and the technical challenges of purifying and storing produced hydrogen [75].

Several processes and technologies incorporating biomass feedstocks into oil sands processes are still in the early stages of investigation or have yet to be investigated at all. The economic viability of using biomass-based diluent produced through hydrothermal liquefaction to replace current fossil fuels used has been investigated [23]. Further research is needed to determine the viability of the technology and what impact it has on GHG emissions. Currently, many countries, including Canada, use biomass feedstock to operate power plants on steam cycles [76]. Given the oil sands' large steam and heated water requirements and changing carbon pricing policies, the use of biomass for thermal energy for oil sands processes should be investigated. Other hydrogen production processes are currently in development, including dark fermentation and catalyzed oxygenation, which could offer other alternatives [75].

4.3.2 Nuclear

While nuclear power is not considered a renewable energy source, with respect to GHG emissions mitigation it is similar to renewable energy because it has no carbon-based emissions. Nuclear energy is used extensively around the world, generally for baseload electricity generation. Considerable public concern about the safety of nuclear plants has delayed substantial growth, but increased volatility in fossil fuel prices and emerging reactor designs are improving the outlook of nuclear options [77]. Recent advances in nuclear technology suggest that smaller and safer plants could be built, to be used for industrial processes and more flexible electricity production rather than strictly large baseload plants [78]. The heat, electricity, and hydrogen requirements of oil sands operations make the industry a good candidate for these newer generation systems [79]. Specifically, plants built for combined steam and electricity production based on market conditions offer significant advantages in the oil sands industry [80]. The Canadian government has identified nuclear energy, specifically through small modular reactors, as a key low carbon development opportunity and the mining sector in particular as a potential area for deployment [81].

Several studies have been conducted to determine the techno-economics of incorporating nuclear technology into a variety oil sands processes. Different reactor designs including the CANDU6, the ACR-700, and small modular reactors have been investigated for both steam and electricity production in oil sands settings [82]. An earlier study found that the pebble bed modular reactor (PBMR), a small modular reactor, showed promise economically for incorporation into SAGD operations for steam production [27]. They also found that an ACR-700 reactor could competitively supply electricity over the Alberta grid or local cogeneration options [27].

Studies have been conducted on using nuclear energy for hydrogen production and for further improvement of small modular reactor designs. Thermochemical hydrogen production has been investigated and could prove to be a more economical option than electrolysis-based systems [83]. Combining electricity production and hydrogen production through load following has also been shown to have potential applications [84]. Finally, other small modular reactor designs that could outperform the PBMR have been reviewed; several designs have significant promise but need to be researched further [78]. Research into the techno-economics of any of these technologies as they develop may provide opportunities to incorporate nuclear energy into oil sands processes to reduce GHG emissions.

4.3.3 Hydro

Canada has considerable hydropower resources available. In 2016, 59% of Canada's electricity was sourced from hydropower, with the provinces of Quebec and British Columbia having the highest capacities [85]. Currently, oil sands processes use electricity generated from cogeneration at oil sands sites or from the Alberta grid, both predominantly using fossil fuels. Incorporating hydroelectricity into oil sands processes, for instance by importing energy from other provinces or increasing Alberta's hydro resources, would reduce their emission intensity [86].

Studies have considered the role of hydropower in oil sands processes, such as using hydro for hydrogen production [30] and to provide low-carbon electricity [86]. Dedicating a hydro dam to electrolysis for hydrogen production has been shown to be a competitive option to current hydrogen production techniques under certain circumstances [30]. Researchers have conducted a large study on opportunities to incorporate hydropower into oil sands processes, specifically with respect to large power supply opportunities that offer steady power output [86]. The results of this study were developed to include British Columbia's Site C Dam and an upgraded intertie to British Columbia's electricity grid into a long-range bottom-up model to forecast economic performance; the study's authors found that the intertie expansion could mitigate 0.7 MT/year of emissions annually at \$72.50/tCO_2e, while the use of Site C could mitigate 1 MT/year at \$226/tCO_2e [87]. An important challenge and source of costs is the infrastructure requirements to transport the electricity from the dam to the oil sands sites.

Studies have not yet considered the use of small-scale or run-of-river hydro dams. Run-of-river hydro plants have the benefits of flexible operation, low construction costs, shortened transmission distances, and lower environmental impact [88]. Run-of-river hydropower is often an economical solution in rural areas long distances from power generation centers [89]. The oil sands meet this criteria, and locations on the Athabasca River near oil sands operations have been identified recently as potentially viable [90]; in other words, transmission distances could be relatively small. Further research into run-of-river hydropower for the oil sands would help understand its potential.

4.3.4 Geothermal

Several studies have been conducted in the Athabasca oil sands region to characterize the geological properties and potential to use geothermal energy [91] [25] [26]. The average temperature gradient in the area is around 21 °C/km, and at the depths where useful temperatures (~5 km) are achieved, the formations are characterized as dry granite, which is challenging to drill through and not generally porous [26]. Overall, the characteristics of the geothermal heat in the oil sands region are not considered optimal, but because of the unique nature of oil sands processes, there is still potential to use geothermal heat. Oil sands extraction from surface-mined products is done with natural gas-heated water in the range of 35-50°C, much lower than required for traditional uses of geothermal energy [91]. Because a large amount of heated water is needed (currently supplied by burning natural gas fuel), there is an opportunity to replace some of the heated extraction water with geothermally heated water. A previous study conducted a simulation study to determine the viability of this practice and found that engineered geothermal systems, where the formation is hydraulically fractured, can meet the required performance of oil sands processes and reduce natural gas demand [25]. Basic studies on geothermal characteristics done through an existing deep well in the area and economic estimates suggest that more research is needed both on well characteristics and cost. Techno-economic studies have found that these systems could be competitive with natural gas heating over 30-year time horizons [26].

Despite the promise shown in the referenced studies, some limitations in the analyses warrant further research. All three studies cited above use data from a single 2.6 km deep well in the Athabasca oil sands and conclude that in general wells would need to be at least 4 km deep to use geothermal heat. There are many unknowns associated with how well-induced fracturing will aid in formation porosity. Additionally, the viability of the results is sensitive to the input fuel costs for natural gas systems, which are influenced by commodity prices and carbon tax. Ultimately, there is substantial room to increase knowledge of expected geothermal well performance in the Athabasca oil sands region.

4.3.5 Solar

The use of solar energy in oil sands processes has not been extensively studied, likely due to the relatively low insolation in oil sands production areas in Northern Alberta. However, there may be an application for intermittent steam supplied by solar energy for certain in situ production applications. An earlier study investigated the use of solar generated steam in the Athabasca oil sands for a 10,000 bpd CSS facility and found that despite the lower insolation values, the system was still cost competitive over the long term [23]. Another study investigated the use of solar steam for heavy oil recovery in the San Joaquin Valley in California [92]. The wells have similar properties to oil sands, making them useful for comparison. A key observation from the study was that the intermittency of steam production from solar power did not have a major impact on well productivity, validating the method of production.

Further research is warranted for oil sands-specific incorporation of solar energy. We did not find any published techno-economic studies on the impact of solar photovoltaic (PV) electricity. Decreasing PV cell costs and high electricity demand in oil sands processes suggest there could be merit in such studies. Additionally, technological developments in solar hydrogen production should be considered for oil sands bitumen upgrading. Solar thermal hydrogen production prospects have improved in recent years [93] and could be cost competitive with SMR under certain conditions.

4.3.6 Wind

Wind energy is a growing form of renewable energy most commonly used for electricity generation. The province of Alberta has had a steady increase of electricity generation through wind power, largely in its southern regions. While the south is geographically separated from the oil sands, research has shown that hydrogen produced through wind-powered electrolysis could be used in upgrading operations. Systems using wind energy to produce hydrogen have been shown to offer a 95% reduction in GHG emissions before transportation compared to SMR hydrogen production, making them an attractive emissions reduction option [22].

Both small-scale single turbine systems and large-scale dedicated wind farms have been evaluated in terms of hydrogen production for oil sands consumption and electricity produced for export to the Alberta grid. In an earlier study, it was assumed the small-scale system used a single 1.8 MW wind turbine with an electrolyser to produce hydrogen that is transported to upgraders by truck [31]. A study by the same authors on large-scale wind farms evaluated their potential in Alberta and the cost of a large electrolyser plant with a hydrogen pipeline feeding bitumen upgraders [32]. The geographical separation between the province's established wind resources in the south and bitumen upgrading facilities in central Alberta means that transporting the produced hydrogen would be a major cost component. No studies were found on the incorporation of wind energy into oil sands processes in other ways.

Table 4-1: Summary of oil sands technology options

Renewable energy technology	Integration options	Technoeconomic data available?	Key technoeconomic results	Comments/sources
Biomass gasification	Bitumen upgrading	Yes	\$2.19-2.31/kg of H_2	Hydrogen production to replace SMR plants [28]
Biomass pyrolysis	Bitumen upgrading	Yes	\$2.40-4.55/kg of H_2	Hydrogen production to replace SMR plants [29]
Biomass hydrothermal liquefaction	Dilbit production	No	-	Production of diluent to replace use of fossil-based light hydrocarbons [23]
Biomass dark fermentation	Bitumen upgrading	No	-	Hydrogen production to replace SMR plants [75]
Biomass catalyzed oxygenation	Bitumen upgrading	No	-	Hydrogen production to replace SMR plants [75]
Nuclear ACR-700 reactor	Electricity	Yes	Competitive with natural gas at \$10/MMBtu	Electricity generation for general industry use [27]
Nuclear small modular reactor	In situ	Yes	Competitive with natural gas at \$6.50/MMBtu	Steam production for SAGD facilities [27]
Nuclear thermochemical hydrogen production	Bitumen upgrading	No	-	Hydrogen production to replace SMR plants [83]
Hydro energy electrolysis	Bitumen upgrading	Yes	\$1.87-2.60/kg of H_2	Hydrogen production to replace SMR plants [30]
Hydro dam	Electricity	Yes	GHG mitigation cost of \$73/tCO_2e	Electricity generation for general industry use [86]
Run-of-river hydro	Electricity	No	-	Electricity generation for general industry use [88]
Geothermal energy	Surface mining	Yes	\$0.06/kWh thermal cost of heat	Further understanding of geothermal gradients in oil sands areas required [91] [26]

Renewable energy technology	Integration options	Technoeconomic data available?	Key technoeconomic results	Comments/sources
Solar heat	In situ – heat	Yes	ROI range of 14 to 20 years	Steam production for CSS facilities [33]
Solar photovoltaic cells	Electricity	No	-	Electricity generation for general industry use
Wind energy electrolysis	Bitumen upgrading	Yes	\$7.48-10.15/kg of H_2	Hydrogen production to replace SMR plants [31] [94]

4.4 Methods

Figure 4-1 shows the overall study framework, that is, the input data and assumptions, the interaction between the models we developed, including the market penetration model and the bottom-up energy accounting model (LEAP), and the outputs. Each section of the framework is explained in further detail below. Economic data is made up of forecasted trends in industry production levels, policies that have a financial impact on the industry, fuel price forecasts for fuels used in the industry, and values used in financial analysis such as the discount rate applied. The reference technologies are those that are currently being used in the industry and alternative technologies are those that are being investigated in this study to potentially replace the reference technologies. The market penetration model is used to project usage rates of competing technologies based on their costs, and the LEAP model is a bottom-up energy accounting model used to calculate energy usage and emission levels of each technology being considered. These models are explained in dedicated sections below.

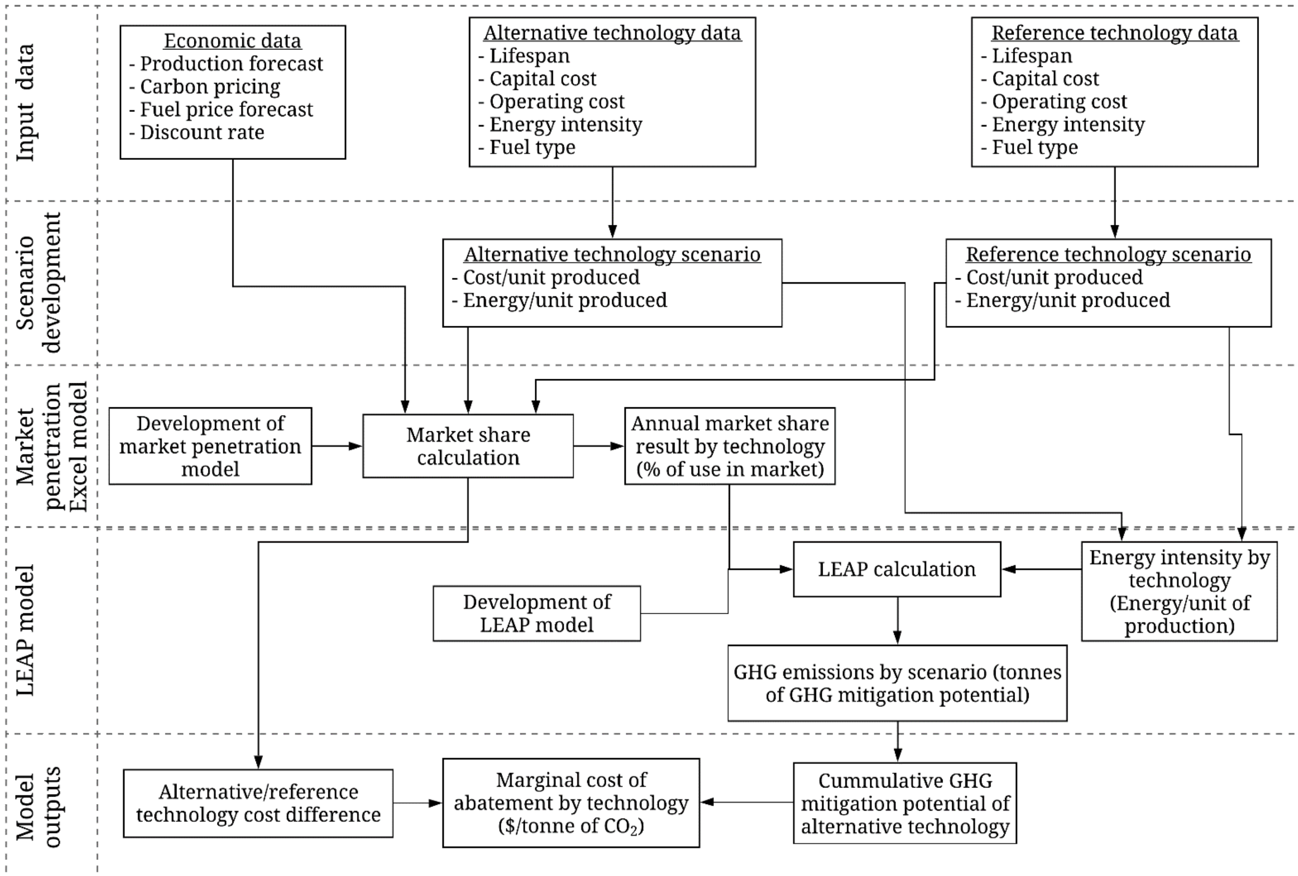


Figure 4-1: Developed analysis framework for assessment of GHG mitigation cost

4.4.1 Input data and assumptions

Economic data for bitumen production forecasts by subsector and fuel price forecasts were taken from the NEB [13] and the Alberta Energy Regulator (AER) [20]. The production forecast used is shown in Figure 4-2 below. NEB data is provided to the year 2040 and trends are extrapolated to 2050. Details of the forecast values entered into the model can be found in Appendix A.

Three different carbon incentive policies were considered for each scenario, each using the outlined carbon incentives in real 2019 $CAD. The first, titled "CP0," does not take any carbon incentive impact into consideration. This allows technologies to be compared independently of policy decisions. The second, "CP30," uses a real price of $30/tCO_2e$ from 2018 to 2050, corresponding to a carbon incentive at this level [95]. The third, “CP50,” uses a real price of \$30/tCO_2e until 2021 and an incentive of \$50/tCO_2e from 2022 to 2050, matching the cost of carbon mandated in the federal government’s Pan-Canadian Framework on Clean Growth and Climate Change [4]. The actual taxable GHG emissions are based on assumed benchmark emission levels for each subsector based on earlier policies [8]. GHG Emissions above the given benchmarks are assumed to be taxable and emissions below them are subject to credits. The market value of the credits is less than the taxation rate [8], with their exact value changing with demand and availability. In this study, the credits are assumed to be 85% of the taxation rate. Sensitivity analysis was performed to determine the impact of a wider range of values. Table 4-2 below shows the GHG emission benchmarks for the industries considered in this study.

Alternative and reference technology data are described in detail in the scenario development section (Section 4.4.2). The costs, lifespans, fuel types, and energy intensities for the alternative technologies were developed and taken from the literature wherever available. Fuel types and energy intensities for current technologies were taken from the previously developed LEAP model for the mining sector [70].

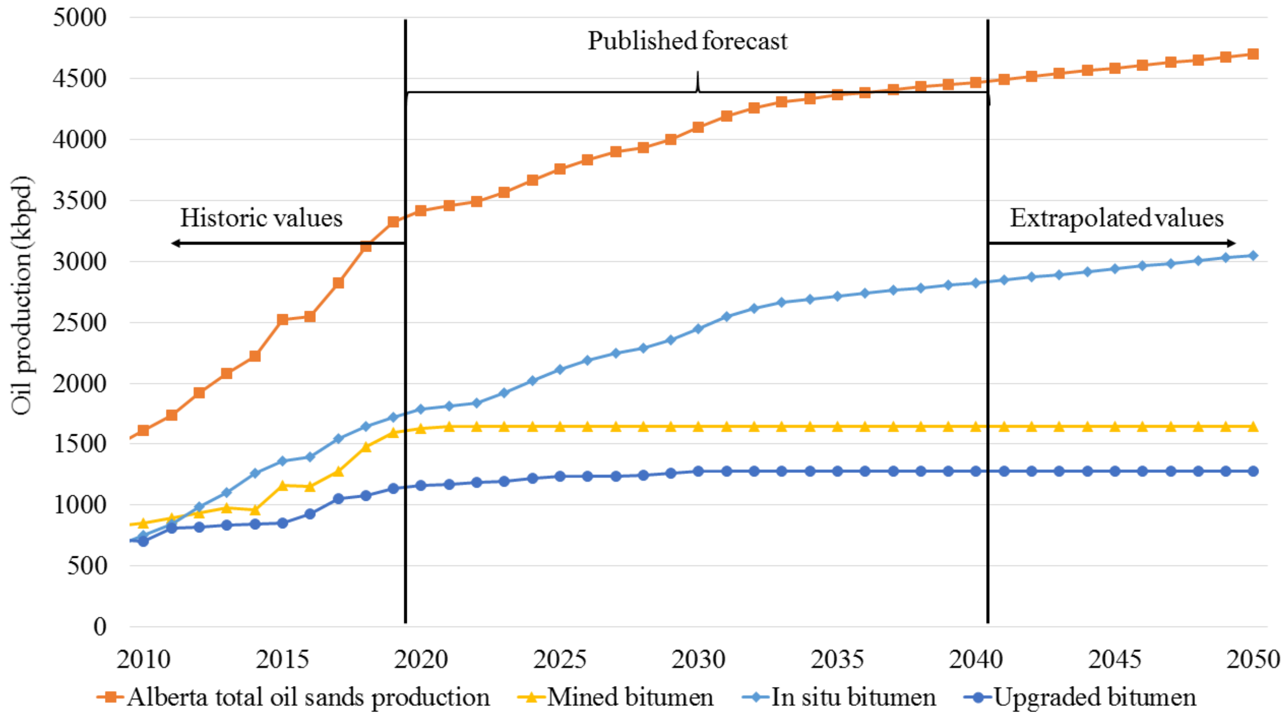


Figure 4-2: Production forecast entered into the LEAP model

Table 4-2: Assumptions based on earlier policies and associated benchmark values [8]

	BE_y: Established benchmark for year *y* (tCO_2e per product unit)						
Product	**2018**	**2019**	**2020**	**2021**	**2022**	**Subsequent years**	**Product unit**
Electricity	0.37	0.37	0.3663	0.3626	0.3589	$BE = BE_{y-1} - 0.0037$	MWh
Hydrogen	7.97	7.97	7.89	7.81	7.73	$BE = BE_{y-1} - 0.08$	Tonne
Oil sands in situ bitumen	0.3504	0.3504	0.3469	0.3434	0.3399	$BE = BE_{y-1} - 0.0035$	m^3 bitumen
Oil sands mined bitumen	0.1954	0.1954	0.1934	0.1914	0.1894	$BE = BE_{y-1} - 0.002$	m^3 bitumen

4.4.2 Scenario development

Developing scenarios involved breaking down bitumen production from the oil sands into major processes and examining the technology options that can be used to reduce emissions in those processes. Figure 4-3 highlights these major oil sands processes and the different renewable and low carbon energy sources that could be integrated in these processes. Technologies with sufficient economic and technical data for scenario development are shown in Figure 4-3. The scenarios were evaluated for the years 2019 to 2050, from the time of this study to the end year of Canada's Mid-Century Long-Term Low-GHG Development Strategy [96] to align with federal clean development strategies.

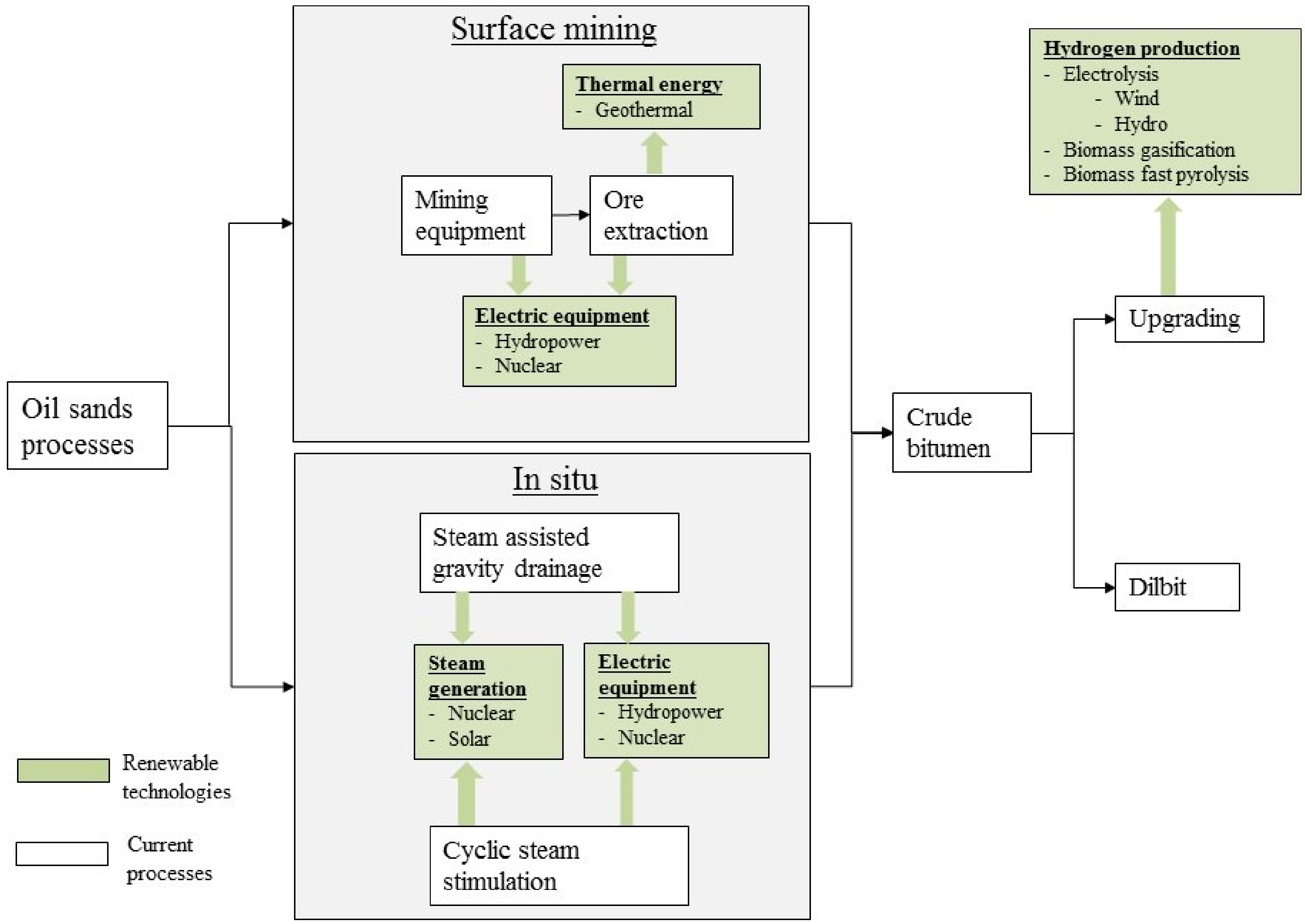


Figure 4-3: Developed framework for integration of renewable technologies applicable to oil sands operations

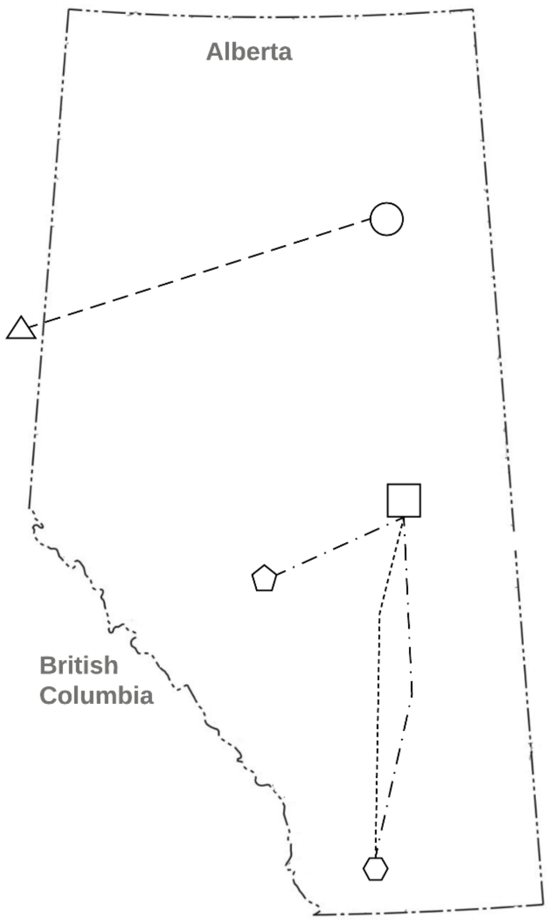
Table 4-3 lists each alternative technology scenario developed. The table shows the scenario names, applicable subsectors, current (reference) technologies that will be replaced in the scenario, fuel sources, annualized lifetime costs, and emission factors (discussed in more detail in Section 4.4.4). Annualized lifetime costs were developed using Equation 4-1 below. Scenario names are based on the fuel or energy source consumed by the technology, the subsector the technology will be used in, and the specific technology used. Scenarios were based on techno-economic data developed for the use of these technologies in oil sands applications. Figure 4-4 shows the approximate geographical locations of technologies when products require transportation and includes details on how the products are transported.

Scenario names are used to differentiate which carbon incentive option is evaluated; the first uses "CP0," the second adds "CP30" to the name, and the third adds "CP50." As an example, the solar CSS scenario under the third carbon pricing option is labelled SOL-CSS-CP50.

Table 4-3: Scenario inputs to penetration model

Subsector integration	Scenario product	Scenario name	Description of technology	Fuel source	Annualized lifetime cost (2019 CAD $/Unit produced) *	Emission factor (kg CO_2/unit produced)	Production unit
Bitumen upgrading	Hydrogen production	Reference	Steam methane reforming (SMR)	Natural gas	1.15 + 0.15*P_{NG} [39]	11.9 [28]	kg H_2
		WIN-H2-TURB	Wind electrolysis - Single turbines	Wind	14.39 [31]	6.4 [31]	kg H_2
		WIN-H2-FARM	Wind electrolysis - Wind farm	Wind	9.69 [32]	1.6 [32]	kg H_2
		HYD-H2-DAM	Hydro electrolysis - Hydro dam	Hydro	2.58 [30]	1.6 [30]	kg H_2
		BIO-H2-GAS	Biomass gasification	Whole tree	2.55 [28]	1.2 [28]	kg H_2
		BIO-H2-PYR	Bio-oil pyrolysis	Whole tree	2.76 [29]	1.6 [29]	kg H_2
Cyclic steam stimulation	Steam production	Reference	Boiler steam	Natural gas	1.39 + 1.43*P_{NG} [33]	63.6	bbl
		SOL-CSS	Solar steam plant	Solar	19.81 [33]	-	bbl
Steam-assisted gravity drainage	Steam production	Reference	Boiler steam	Natural gas	1.23 + 1.30*P_{NG} [27]	56.3	bbl
		NUC-SAGD-MOD	Small modular nuclear reactor	Nuclear	6.20 + EC [27]	-	bbl
Surface mining extraction	Process heat production	Reference	Natural gas heating	Natural gas	0.32*P_{NG} [26]	41	bbl
		GEO-EXT-LOW	Geothermal - Low well flow	Geothermal	10.41 [26]	14.4 [26]	bbl
		GEO-EXT-HI	Geothermal - High well flow	Geothermal	2.6 [26]	14.4 [26]	bbl
Electricity	Electricity for general industry use	Reference	Cogeneration plants	Natural gas	37.98 + 7.72*P_{NG} [27]	440	MWh
		NUC-ELEC-ACR	ACR700 reactor	Nuclear	68.51 + EC [27]	-	MWh
		HYD-ELEC-DAM	AB-BC intertie expansion	Hydro	81 [86]	-	MWh

* P_{NG} = *price of natural gas; EC = energy cost; a detailed breakdown of data used to develop these values is available in the Appendix B*



Scenario	Production location	End-use location	Transport method
WIN-H2-TURB	Pincher Creek	Fort Saskatchewan	Truck
WIN-H2-FARM	Pincher Creek	Fort Saskatchewan	Pipeline
HYD-H2-DAM	Brazeau Dam	Fort Saskatchewan	Pipeline
BIO-H2-GAS	Fort Saskatchewan	Fort Saskatchewan	N/A
BIO-H2-PYR	Fort Saskatchewan	Fort Saskatchewan	N/A
SOL-CSS	Fort McMurray	Fort McMurray	N/A
NUC-SAGD-MOD	Fort McMurray	Fort McMurray	N/A
GEO-EXT-LOW	Fort McMurray	Fort McMurray	N/A
GEO-EXT-HI	Fort McMurray	Fort McMurray	N/A
NUC-ELEC-ACR	Fort McMurray	Fort McMurray	N/A
HYD-ELEC-DAM	BC - Site C Dam	Fort McMurray	AC power line

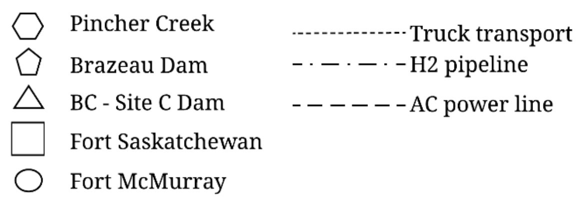


Figure 4-4: Overview of scenario locations and commodity transportation methods (map taken from NRCan and used in accordance with the Canadian Open Government Licence [97])

4.4.3 Market penetration model

The selected technologies were evaluated to determine their market penetration. The equations used in this study were developed in an earlier study for the energy industry to evaluate climate policy decisions using annualized costs [57]. The annualized cost of each technology includes capital costs, operating expenses, carbon costs, and energy costs and is shown in Equation 4-1, taken from literature [35].

$$\mathrm{LCC_j} = \left(\mathrm{CC_j} \times \frac{i}{1-(1+\mathrm{i})^{-n}}\right) + \mathrm{OC_j} + \mathrm{ECC_j} + \mathrm{EC_j} \tag{4-1}$$

In the equation, for technology j, LCC_j is the annualized lifetime cost of technology j, CC_j is the overnight capital cost, OC_j is the annual operation and maintenance costs, ECC_j is the annual emitted carbon cost (if a carbon incentive policy is in place), and EC_j is the annual energy or fuel cost. In order to get an annualized value for capital costs, the capital recovery factor is calculated using interest rate i and technology lifetime n. All economic evaluations of scenarios were conducted using the same key parameters for both reference and new technology scenarios. This includes converting costs to 2019 $CAD and using an internal rate of return (IRR) of 10% for the interest rate. Technology lifetime was determined for each technology specifically based on expected performance and is provided for each technology in Table 4-3. The results from the annualized lifetime costs were used in the market share algorithm shown in Equation 4-2, which simulates technology competition and is taken from literature [35].

$$\mathrm{MS_j} = \frac{\mathrm{LCC_j^{-v}}}{\sum_{\mathrm{j=1}}^{\mathrm{k}} \mathrm{LCC_j^{-v}}} \tag{4-2}$$

In Equation 4-2, $\mathrm{MS_j}$ is the market share for technology j in the year being calculated, v is the cost variance parameter, and k is the number of competing technologies in the subsector being considered. An earlier study discusses appropriate values for the cost variance parameters and assigns a value of 8 to the energy industry [35]. The annual market share of each technology is determined with this value based on the amount of new production forecasted that year and the percent market share determined through the penetration model. Annual new production amounts are driven by production forecasts. Inputs for the cost and GHG emission factors for the penetration model are shown in Table 4-3. P_{NG} is the annual forecasted price of natural gas and *EC* is from Equation 4-1 above; costs of non-natural gas sources are expected to vary from year to year.

Market share results are used directly in the bottom-up techno-economic model after the given technology has achieved enough market share to meet that technology's minimum plant capacity. Additionally, nuclear technology penetrations are delayed until 2028 to allow for a 10-year licensing period, given the complexity of gaining regulatory approval for new commercial nuclear reactors in Canada. Emission factors for reference scenarios were determined using LEAP's Technology and Environmental Database, which uses the latest International Panel on Climate Change (IPCC) emission factors.

4.4.4 Long-term energy and GHG accounting using LEAP

The model used in this study is a continuation of the LEAP (LEAP-Oil Sands) model discussed above in the introduction. The model was further developed here by adding technologies and their energy and emission information for each renewable/low carbon scenario considered, updating baseline data, and incorporating the market penetration results into the model. User-defined emission factors were used in all the bitumen upgrading subsector scenarios to account for the additional emissions related to transporting hydrogen from the production site to upgraders, as shown in Figure 4-4. User-defined emission factors were also used for geothermal scenarios because the geothermal energy used does not completely eliminate the need for natural gas boilers in these scenarios. Market penetration results were entered into the model as percentages to define the rate of use of each technology.

4.4.5 Model outputs

We calculated the expected cost of GHG mitigation in dollars per equivalent tonnes of carbon dioxide ($/t$CO_2$e) with the output from the LEAP-Oil Sands model for each of the three carbon pricing regimes and the life cycle costs of each technology.

$$Scenario_x\ GHG\ Mitigation\ [\$/tonne] = \sum_{n=i}^{n} \frac{ScenarioCost_{xn} - ScenarioCost_{BAUn}}{ScenarioEmissions_{BAUn} - ScenarioEmissions_{xn}} \tag{4-3}$$

In Equation 4-3, $Scenario_x\ GHG\ Mitigation$ is the total mitigation potential over the examined time period for scenario x, $ScenarioCost_{xn}$ is the annual cost associated with implementing scenario x in year n, $ScenarioCost_{BAUn}$ is the annual cost of the BAU scenario in year n, $ScenarioEmissions_{BAUn}$ is the emissions expected in the BAU scenario in year n, and $ScenarioEmissions_{xn}$ is the emissions expected from scenario x in year n.

The GHG emissions were determined using the emissions calculated in the LEAP model based on energy demand. Renewable technology scenarios with non-zero emission factors to account for transportation emissions were manually added into the LEAP model using the emission factors shown in Table 4-3. The forecasted total cost of mitigation was determined by calculating the difference between the annual costs of the renewable technology and the currently used technology in the reference case. Scenario costs were calculated using costs from the market penetration model, and future cash flows were discounted at a rate of 5% to 2019 dollars.

4.4.6 Sensitivity analysis

The sensitivity of market penetration and GHG abatement cost results to key variables – cost variance parameter, IRR, natural gas price, industry growth, and carbon credit values – was tested. The cost variance parameter was tested across a range of values that could be applied to the energy industry. The IRR was tested because most technologies considered in this study are in the early stages of development and the risk associated with investment is not well understood. Natural gas price was tested because it is the main form of energy competing with renewable energy technologies and is historically difficult to predict. Annual production is also historically difficult to forecast and was tested mainly to examine its impact on overall mitigation potential. Carbon credits vary depending on availability and demand, and average values are not publicly available. For that reason, the assumed market value of 85% of the taxation rate was changed by +/- 10% to determine the effect on results.

4.5 Results and discussion

4.5.1 Market Penetration

The technology penetration results for each scenario to 2050 with the maximum penetration possible are shown in Figure 4-5 below. The upgrading subsector, in which hydrogen production technologies were considered, has a maximum penetration of 18% based on forecasted growth. The penetration results from this subsector show that biomass gasification (BIO-H2-GAS-CP50) and hydro electrolysis - hydro dam (HYD-H2-DAM-CP50) will gain the largest market share, capturing 2.8% and 2.6% of the total by 2050 under the highest carbon pricing considered. Biomass gasification benefits from relatively low operating costs compared to the other options, and hydro electrolysis had significantly lower capital costs per unit of hydrogen produced to offset the higher operating costs of electrolysis and transportation costs. The different levels of carbon incentive more than tripled market shares; for instance, BIO-H2-GAS finished with 0.9% of the hydrogen market with no carbon incentive and 2.8% under the highest carbon incentive because of the reduced carbon emissions associated with the renewable hydrogen options. Wind energy scenarios (WIN-H2-TURB and WIN-H2-FARM) failed to gain any market share under any scenario because of their high capital costs and the high cost of transporting the produced hydrogen from the southern part of the province to the location where it is needed by the oil sands industry and therefore were not analyzed further. The results show that the renewable technologies considered for hydrogen production are only expected to gain a small market share, if any, during the analysis period because of their relatively high cost compared to currently used steam methane reforming technologies. Given the low penetration, it is expected that these technologies will not offer substantial GHG abatement in the analysis period.

Two technologies were considered for in situ production, one to replace natural gas based steam for SAGD and the other to replace natural gas based steam for CSS. The highest penetration in the SAGD subsector is 58%, and the CSS subsector does not currently forecast any growth. Nuclear modular reactors producing steam for SAGD (NUC-SAGD-MOD scenarios) showed the highest penetration of any technology considered. These results were based purely on the cost and performance projections of the technology and do not account for the varying levels of social acceptance of nuclear technologies. The level of social acceptance is expected to impact the ability of a technology to penetrate the market, however that is outside the scope of this research. Under high carbon incentive assumptions (CP50), NUC-SAGD-MOD captured over 11% of the total market share by 2050, despite a delayed start. Since the potential for market penetration is based on new production alone after 2018, SAGD scenarios have the highest market penetration potential. The nuclear-SAGD-steam scenarios perform well because of both the expected large growth of the SAGD subsector and the strong economic performance of the nuclear SMR technologies as shown in an earlier study [27] . Solar steam did not gain any market share in the CSS subsector during the analysis period, due to its high cost and the lack of growth expected in CSS.

Geothermal energy was considered for bitumen extraction process heat in surface mining applications in two well performance scenarios (GEO-EXT-LOW and GEO-EXT-HI). GEO-EXT-LOW did not gain any market share in any scenario. The maximum penetration possible in surface mining was found to be 23%. GEO-EXT-HI results for the CP30 and CP50 scenarios were similar during the evaluation period; both gained less than 1% of the market by 2050. Given the low penetration, this technology is not expected to have a major impact on overall emission abatement.

Hydroelectricity (HYD-ELEC-DAM) and nuclear electricity (NUC-ELEC-ACR) were both considered in the electricity generation subsector of the oil sands industry. Because of industry-wide increasing electricity demand driven by forecasted growth in various subsectors that use electricity, the maximum penetration in the electricity subsector was forecast to be 35%. HYD-ELEC-DAM gained some market penetration in certain scenarios but not enough to meet the minimum production requirement based on hydro dam sizes that could feasibly be used in the oil sands and was therefore not analyzed further. The penetration of NUC-ELEC-ACR justified constructing one reactor in both carbon pricing scenarios and resulted in a final-year market share of 17%. Because of the higher carbon pricing in CP50, the reactor could be justified earlier and therefore is expected to offer higher emission abatement potential.

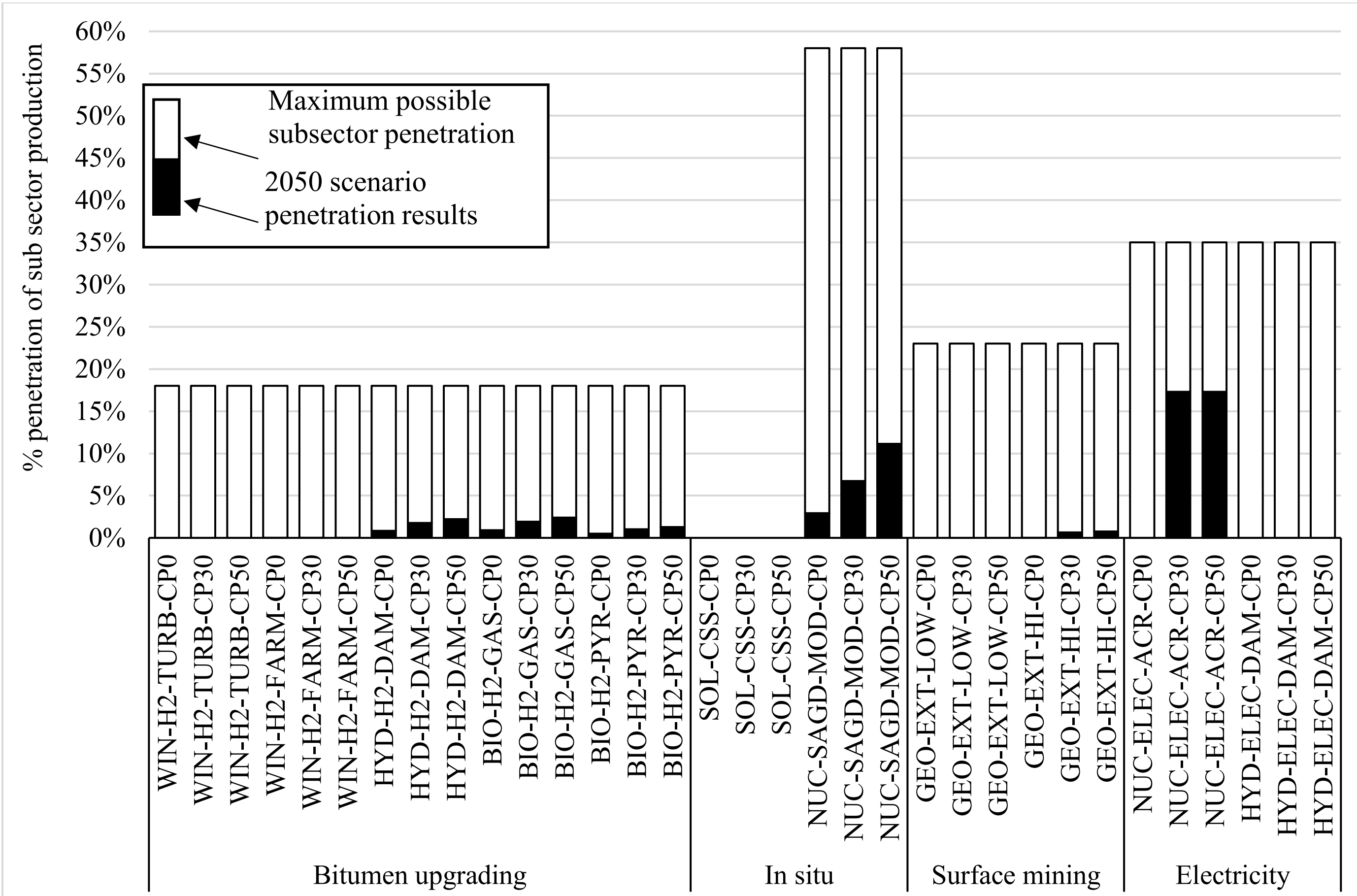


Figure 4-5: Market share results in 2050 by scenario based on maximum subsector penetration potential

It is worth noting that the market penetration models used in this study are based on the financial performance of each technology. Considerations such as increased risk of investment in new technologies are accounted for by performing sensitivity analysis on rate of return requirements for investment.

The effects of carbon incentives on technology penetration varied across the scenarios and generally resulted in increased penetration. Nuclear electricity scenarios (NUC-ELEC-ACR) did not gain any market share under no carbon pricing options but gained more than 17% of the market in both scenarios that used a carbon price. This is because the carbon incentive encourages enough penetration to meet the technology's minimum production level. In nuclear SAGD steam scenarios

(NUC-SAGD-MOD), the 2050 market shares were 2.9%, 6.7%, and 11.1% for no carbon incentive, CP30, and CP50, respectively; these results show the most substantial change from no carbon cost to CP30, while the difference between the CP30 and CP50 results is less pronounced. This trend is consistent for the bitumen upgrading subsector technologies that gained market shares.

4.5.2 GHG emissions mitigation

The cumulative mitigation potentials from all the technologies for the 2019-2050 evaluation period under CP0, CP30, and CP50 are 24 MT, 64 MT, and 116 MT, respectively. These values translate to 0.7%, 1.8%, and 3.3% reductions in total oil sands emissions for the three scenarios. The results show significantly increased penetration and resulting GHG emission reductions due to carbon incentives, with the CP50 scenarios providing 92 MT more abatement potential than the CP0 scenarios. These results are mainly driven by the nuclear SAGD steam (NUC-SAGD-SMR) and nuclear electricity (NUC-ELEC-ACR) scenarios, which show 18 MT and 0 MT of cumulative abatement potential in CP0, and 82 MT and 17 MT of cumulative abatement potential in CP50.

Figure 4-6 shows the annual GHG emissions results for all scenarios and for scenarios with GHG emissions from sources excluded from the current 100 MT annual emissions cap removed and the emissions cap shown. The cap excludes emissions from upgrading operations built or expanded after 2015 and emissions from the electricity generation portion of cogeneration plants [98], therefore upgrading subsector scenarios were not included in the GHG emissions cap relevant scenario results. The reference case projection shows the GHG emissions cap will be exceeded in 2040. The only scenario that resulted in GHG emission reductions significant enough to delay the cap being exceeded in 2040 was the nuclear SAGD steam (NUC-SAGD-MOD-CP30) scenario, where the cap was not exceeded until 2047. The nuclear electricity scenario (NUC-ELEC-ACR) shows GHG emissions slightly decreasing in 2048. This is because penetration levels reach a point where a nuclear reactor dedicated to electricity production is constructed. Given the size of the ACR-700 reactor modeled in this scenario, the nuclear electricity scenario's market share will increase from 0% to 17% and thus make a noticeable impact on overall GHG emissions when the facility begins to generate electricity.

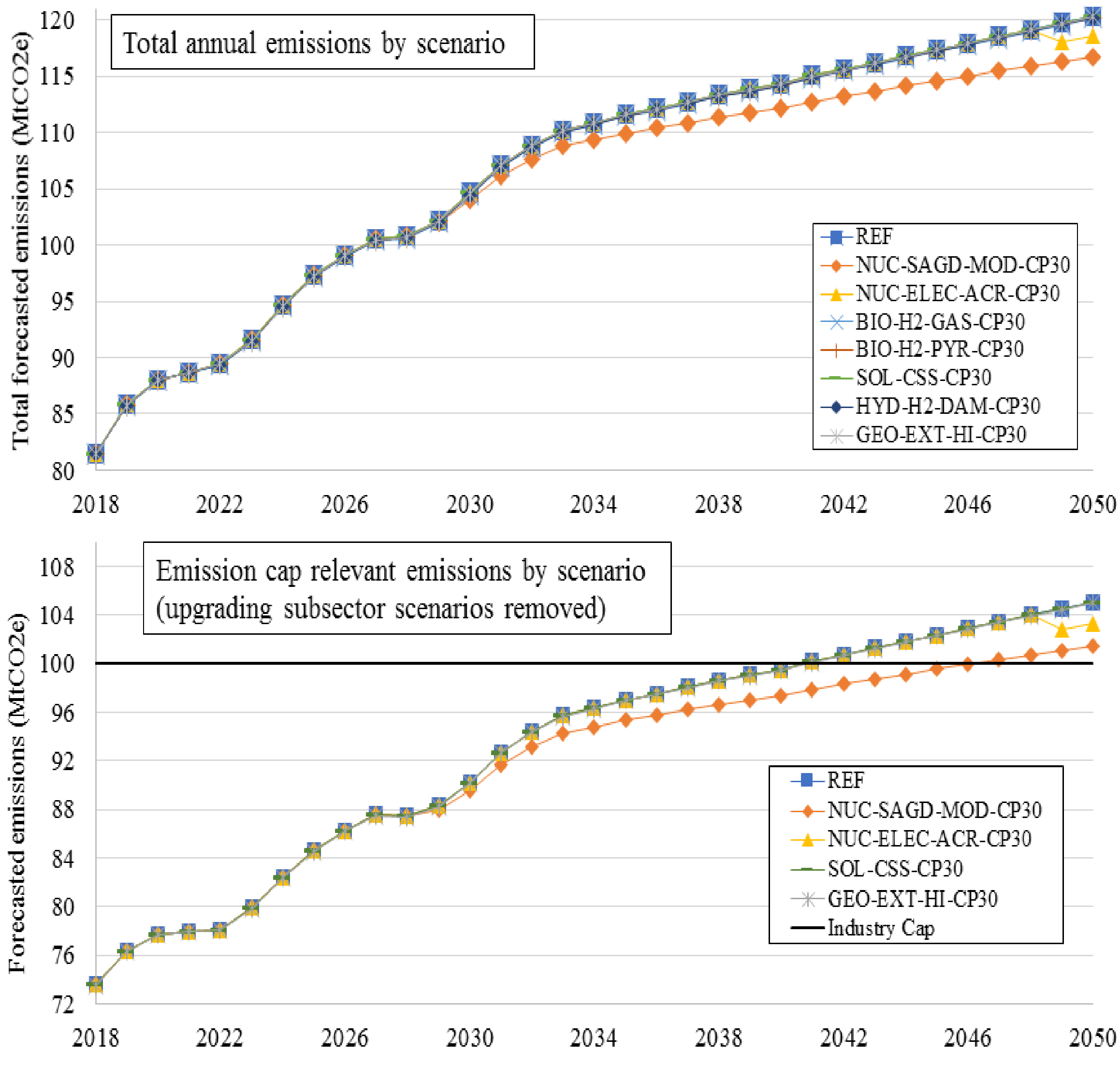


Figure 4-6: CP30 scenario annual emission results including total emissions (top) and emissions cap (bottom) relevant emissions

Figure 4-7 shows the breakdown of individual scenario impact on the overall GHG emission levels for the oil sands for the years 2030, 2040, and 2050 to provide further understanding of the proportion of mitigation offered by each scenario. The mitigation from the nuclear SAGD steam scenario (NUC-SAGD-MOD) consistently provides the greatest portion of mitigation after 2040 despite the delay in penetration until 2028. This is due to the relatively fast penetration of the technology (because of its low cost) compared to the reference scenario and the high expected growth of the SAGD subsector giving the technology opportunity to grow. Other scenarios perform much more closely, with biomass gasification and hydro electrolysis for hydrogen production offering the next greatest mitigation levels under all carbon prices. These technologies were consistently projected to be more expensive than the reference technology's, resulting in lower abatement potential. Carbon incentives were found to have a significant impact on the nuclear electricity scenario, however. Given the large size of ACR-700 nuclear electricity plants, penetration levels did not justify building a reactor until 2048 under CP30 conditions, thus the scenario offers no mitigation potential until later years. This delay results in a low cumulative abatement potential of the nuclear electricity scenario, despite high penetration levels after the facility is constructed.

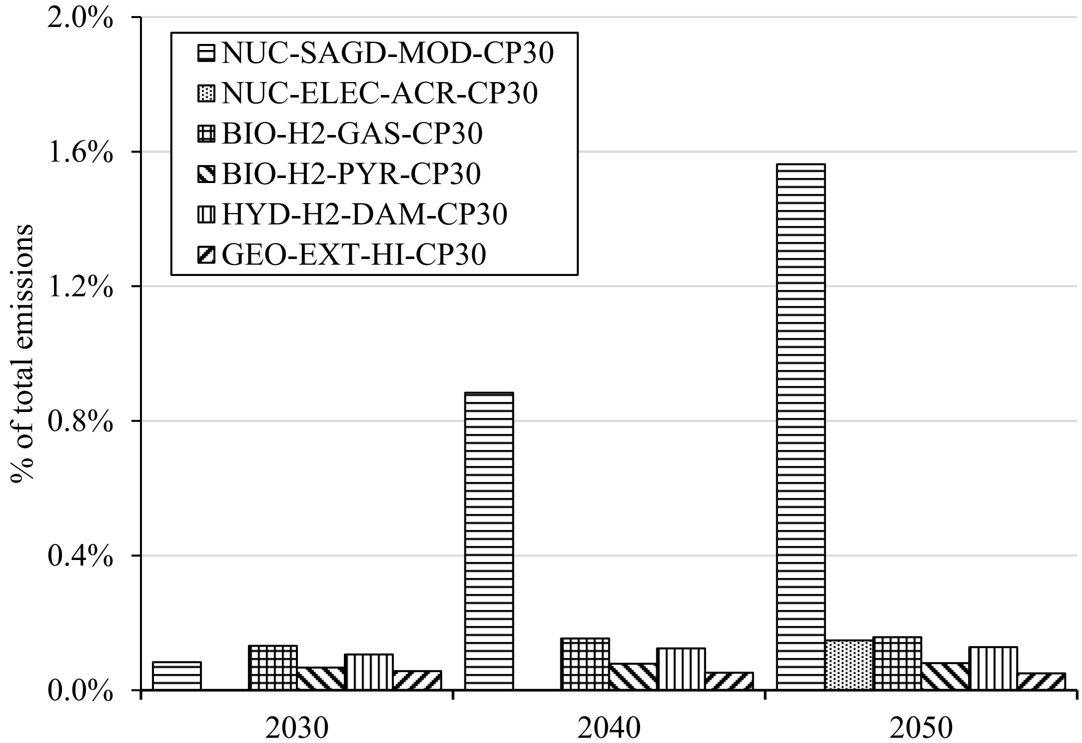


Figure 4-7: Mitigation potential as a percent of total oil sands emissions by scenario

4.5.3 Marginal GHG abatement cost curves

The cost curves in Figure 4-8 depict the mitigation potential and associated cost forecasted for each scenario in the 2019-2050 evaluation period under each carbon incentive option. The cost curves show a combination of the GHG abatement potential and the marginal cost of abatement for each scenario evaluated. Because all the scenarios can, in theory, be implemented together, the total mitigation possible for each carbon incentive is shown in the highest horizontal axis value.

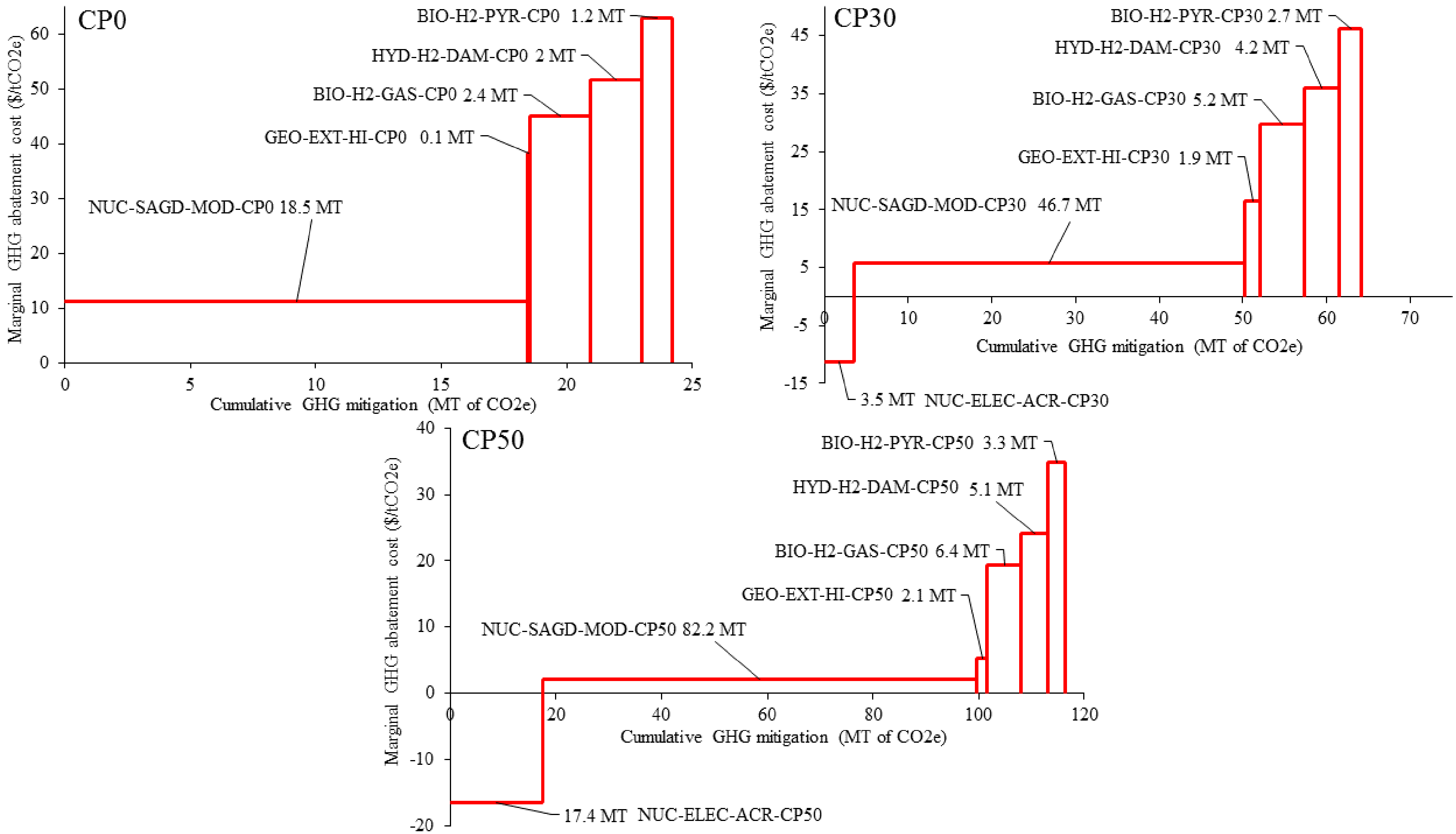


Figure 4-8: 2019-2050 GHG mitigation cost curves with no carbon price (top left), $30/t carbon price (top right), and $50/t carbon price (bottom) policies

Nuclear electricity (NUC-ELEC-ACR) is the only scenario that shows cost savings; the marginal abatement costs are -\$11/tCO_2e at CP30 and -\$17/tCO_2e at CP50. These results are from a combination of expected increases in natural gas prices that fuel cogeneration electricity and the high productivity of nuclear electricity plants. Implementing all the scenarios together results in cumulative mitigation prices of \$20.70/tCO_2e at CP0, \$10.68/tCO_2e at CP30, and \$2.25/tCO_2e at CP50. These results show that the carbon incentive policies have a significant impact on the viability of these technologies; the marginal cost of abatement falls by more than half from the no carbon pricing to a \$30/t situation. Following the CP50 policy framework would result in technology deployment at near breakeven marginal costs.

4.5.4 Sensitivity analysis

Sensitivity analysis was conducted on key variables for each scenario to determine the impact of changes on market penetration, GHG abatement potential, and marginal cost of abatement. The sensitivity analysis results of the CP30 scenario are presented here, as these are most relevant to current policies in Canada. No major differences in sensitivity trends were observed in the results from the other carbon incentive scenarios. The results of the sensitivity analysis showed that key results were most sensitive to changes in natural gas price and internal rate of return used, suggesting that low natural gas price forecasts and perceived risks associated with the technologies are two key barriers for the considered technologies becoming more viable in the market.

An earlier study suggests that an appropriate cost variance parameter in Equation 4-2 could range from 6 to 10 [35]. Therefore, sensitivity analysis was conducted on market penetration results over that range, with results shown in Figure 4-9. NUC-SAGD-MOD-CP30 changed the most, gaining 8.4% of the market at value 6 and 5.3% of the market at value 10. Due to the large minimum production for single facilities, NUC-ELEC-ACR-CP30 scenarios remained at the same market penetration at higher cost variance parameter values, not gaining enough additional market to justify a second facility. At lower values of 6 and 7, NUC-ELEC-ACR-CP30 did not achieve the minimum production for a single facility, therefore the 2050 penetration results were 0% in both cases. When the value was 6, NUC-ELEC-ACR-CP30 did not penetrate sufficiently during the evaluation period to justify constructing a plant.

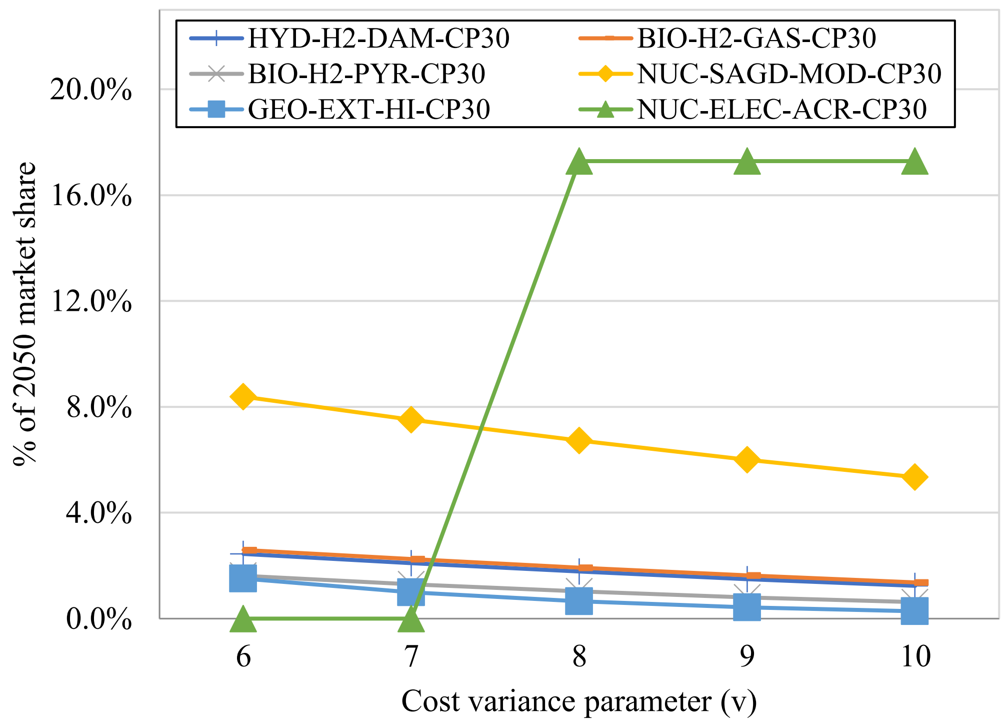


Figure 4-9: Sensitivity of the 2050 market share results to changes in the cost variance parameter.

Changes in natural gas prices and the IRR used in the financial analysis had more substantial impacts on market penetration results than changes in cost variance. Figure 4-10 shows the expected 2050 market share of each scenario as the forecasted natural gas price is changed by +/- 20%, roughly matching the high and low price scenarios forecasted in literature [20]. The NUC-SAGD-MOD-CP30 scenario changes most substantially, gaining only 2.1% of the market if natural gas prices are 20% lower than forecasted and gaining nearly 14.2% of the market if natural gas prices are 20% greater than expected. At lower natural gas prices than the base case, the NUC-ELEC-ACR-CP30 scenario did not gain enough market share to meet the minimum production for a single facility. Figure 4-11 shows the expected 2050 market share when financial analysis is conducted using IRR values of 5% to 15%. Again, the most substantially impacted scenario is NUC-SAGD-MOD-CP30, in which market share reaches 22% at 5% IRR and is as low as 1.2% at 15% IRR. This change can be attributed to the high capital cost of nuclear facilities compared with natural gas boilers and shows the value in reducing the perceived financial risk of nuclear technologies through further research.

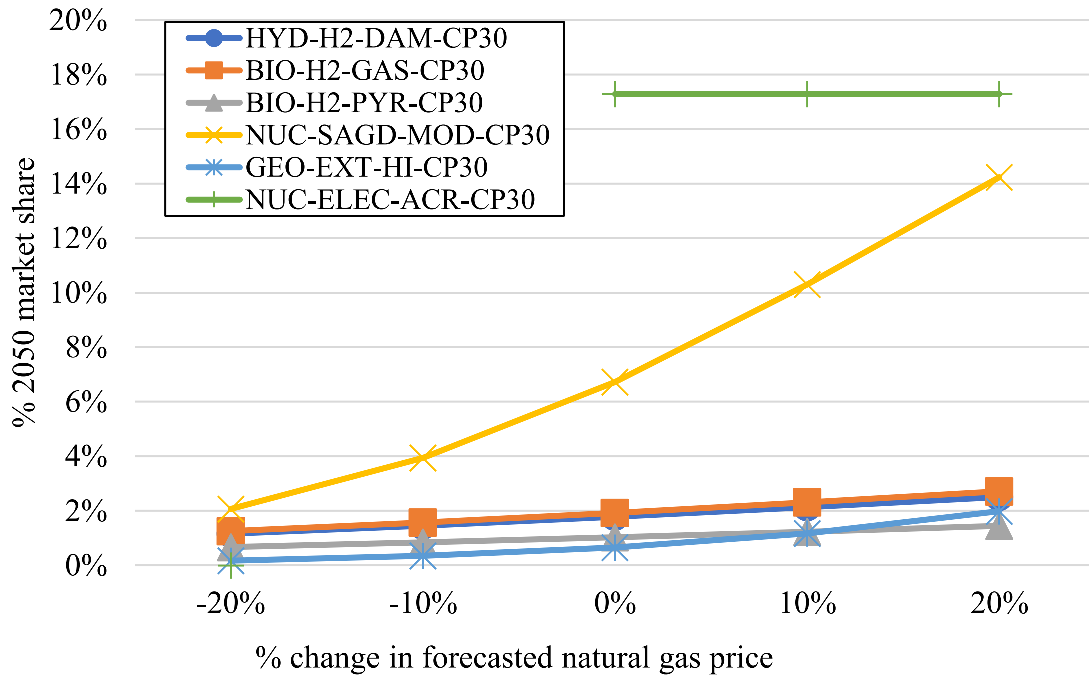


Figure 4-10: Sensitivity of 2050 market share results to changes in the natural gas price forecast.

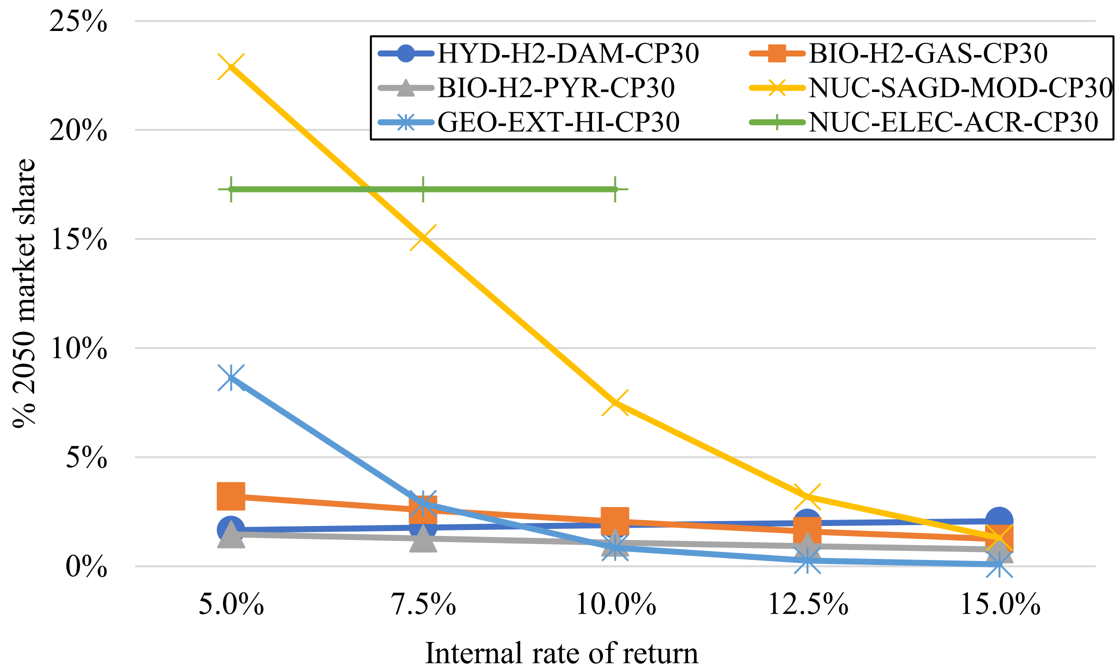


Figure 4-11: Sensitivity of 2050 market share results to changes in IRR.

The sensitivity of marginal GHG abatement cost results to changing the forecasted natural gas price by +/- 20% is shown in Figure 4-12. The scenarios show similar sensitivity trends to changes in natural gas price. NUC-SAGD-MOD-CP30 and BIO-H2-GAS-CP30 show less variance than other scenarios. NUC-SAGD-MOD-CP30 and GEO-EXT-HI-CP30 both result in overall cost savings when natural gas prices are 20% greater than forecasted. NUC-ELEC-ACR-CP30 did not have great enough penetration to justify use when natural gas prices were lower than forecast but in all other cases provided overall cost savings.

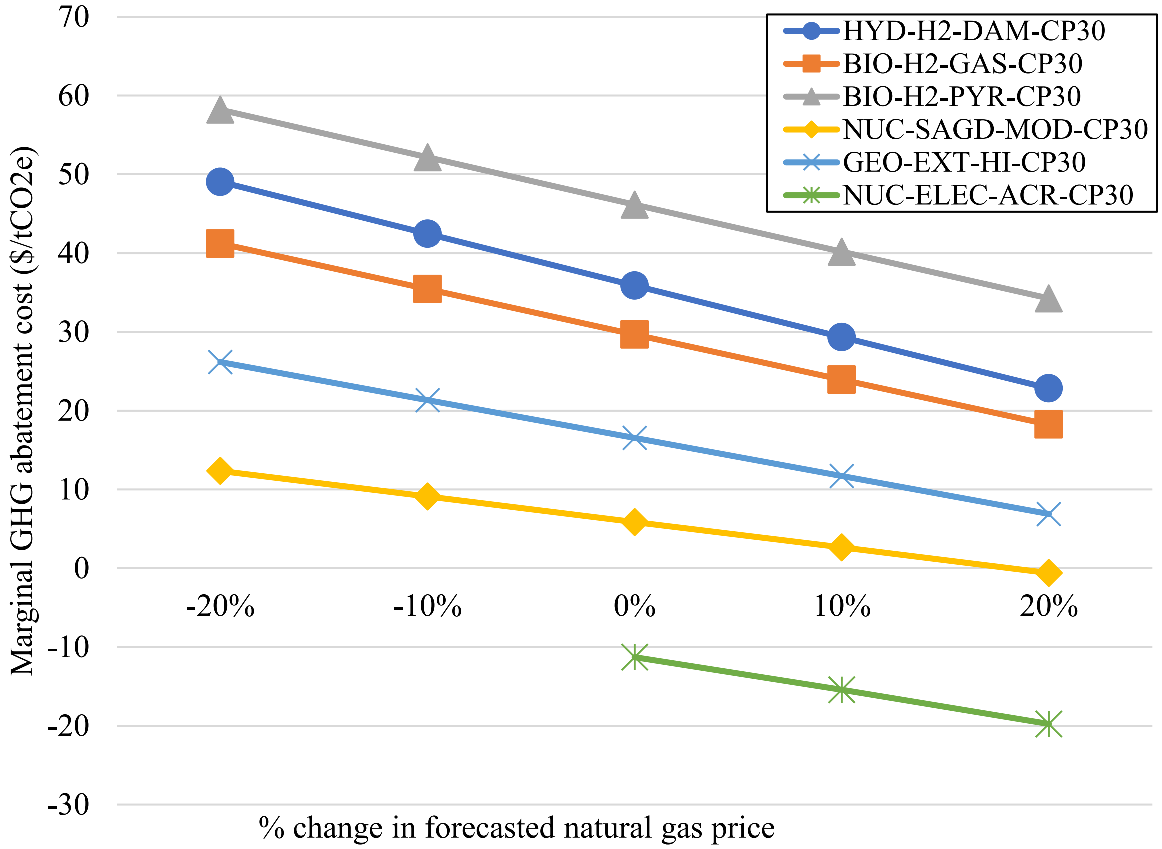


Figure 4-12: Sensitivity of marginal cost of GHG abatement to changes in the natural gas price forecast.

The sensitivity of total abatement results to changes in market growth is shown in Figure 4-13. Market growth projections were changed from -20% to +20% of forecast and the total abatement in each scenario was determined. This range roughly captures the range of values in the "low growth" and "high growth" scenarios provided in the NEB forecast [13]. NUC-ELEC-ACR-CP30 failed to gain enough penetration to build a plant in reduced growth scenarios and thus resulted in 0 MT of mitigation. The same scenario ranged from 5 MT of abatement at forecasted market growth to 24 MT of abatement when growth forecasts are increased by 20%. The remaining scenarios changed linearly, with NUC-SAGD-MOD-CP30 differed most substantially, from 43 MT to 63 MT. The bitumen upgrading subsector scenarios varied similarly, with

BIO-H2-GAS-CP30 ranging from 2 MT to 3 MT.

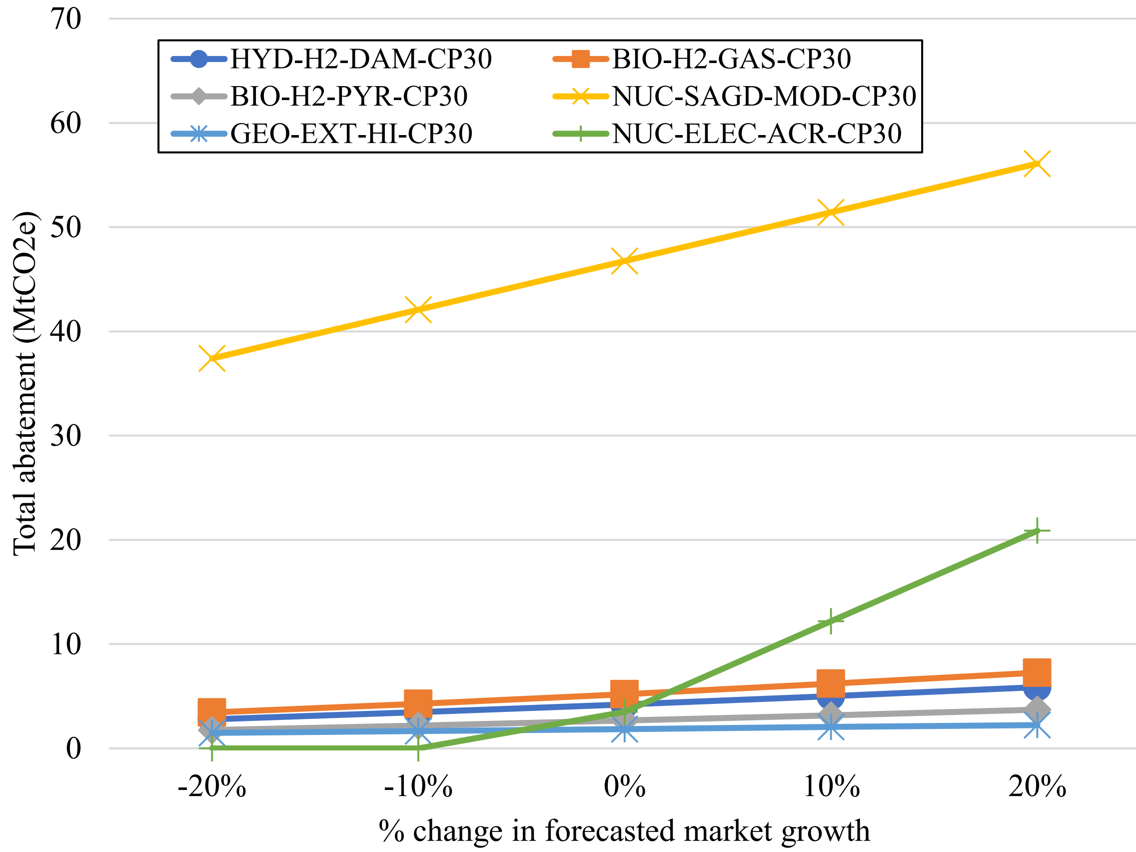


Figure 4-13: Sensitivity of total GHG abatement potential to changes in the market growth forecast.

Figure 4-14 shows the sensitivity of the marginal cost of GHG abatement results when IRR is changed from 5% to 15%. The IRR selected for evaluating the nuclear costs had the most significant impact on the penetration model and subsequently the total mitigation and technology mitigation cost. HYD-H2-DAM-CP30 showed the least sensitivity to changes in IRR, and both the GEO-EXT-HI-CP30 and NUC-ELEC-ACR-CP30 scenarios had expected cost savings from 5% to 10% IRR. No results for NUC-ELEC-ACR-CP30 were recorded above 10% IRR because penetration was not significant enough to justify constructing a reactor. In the case of NUC-SAGD-MOD-CP30, results ranged from -\$6/t at 5% IRR to \$19/tCO_2e at 15% IRR. Considering that this scenario provided the highest total mitigation, the resilience to changes in IRR is an added benefit to its use. The sensitivity results for IRR also reveal the importance of further performance research into these technologies in order to reduce perceived risk in their use.

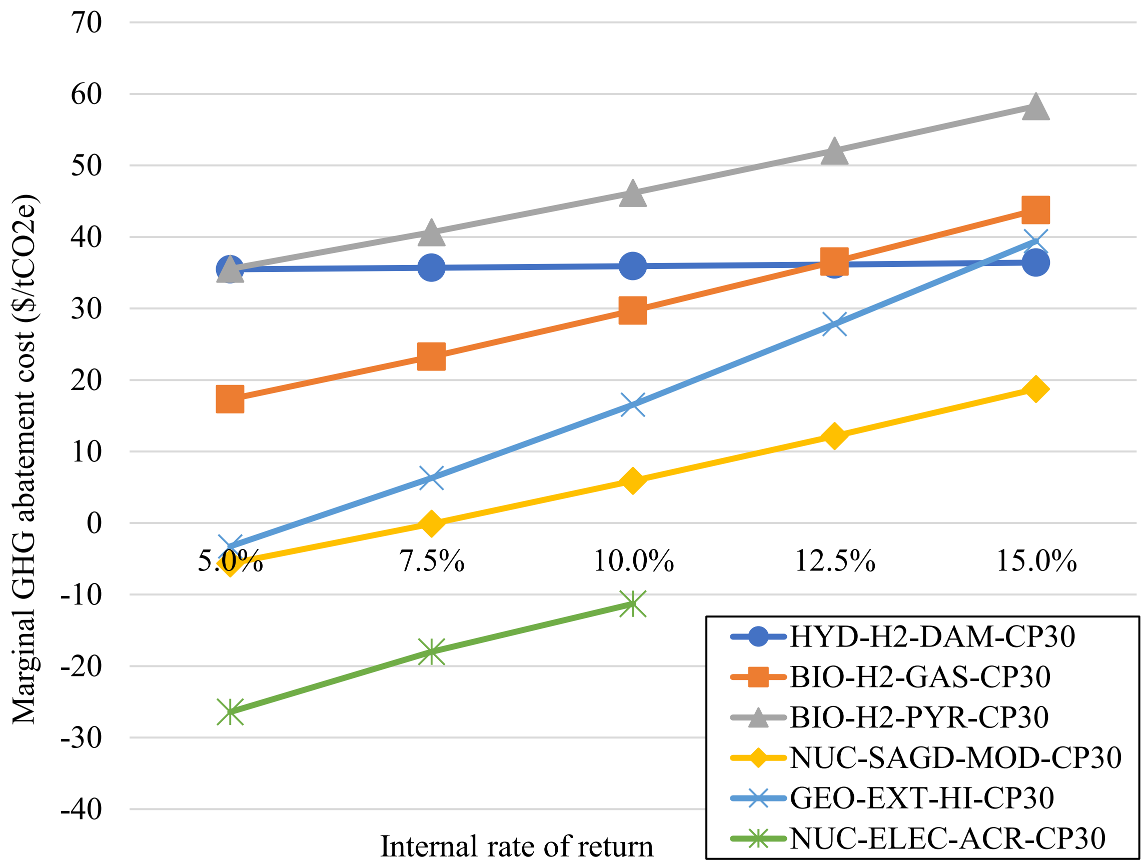


Figure 4-14: Sensitivity of marginal GHG abatement cost results to changes in IRR.

The impact on marginal cost of GHG abatement results in each scenario to changes in the relative value of carbon credits is shown in Figure 4-15. The average change in the marginal cost across the scenarios was $1.74 from credits being sold at 75% and 95% of the taxation rate. The results were relatively consistent across the scenarios with the greatest difference being $2.04/tCO_2e$ in GEO-EXT-HI-CP30 and the lowest being $0.95/tCO_2e$ in NUC-SAGD-MOD-CP30. When credits were at or below 80% of the taxation rate value, penetration results no longer justified the construction of a facility in the NUC-ELEC-ACR-CP30 scenario.

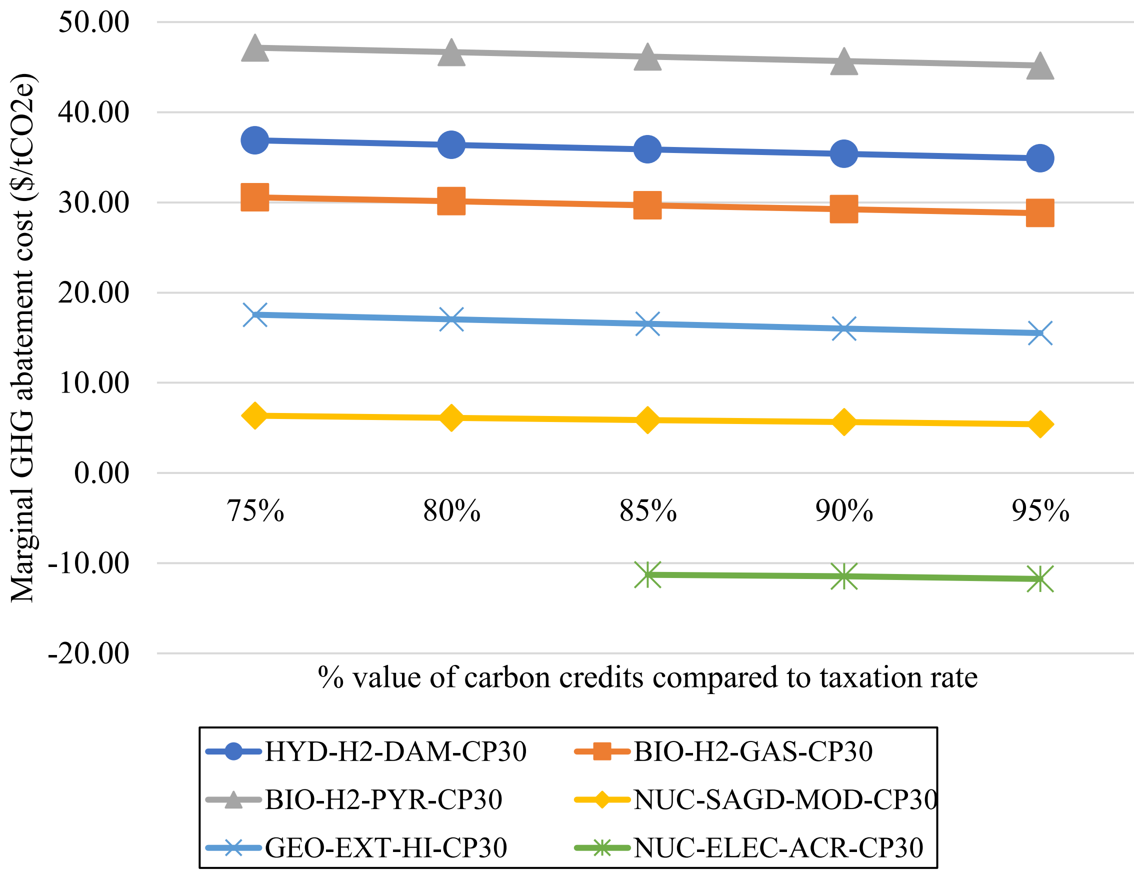


Figure 4-15: Sensitivity of marginal cost of GHG abatement results to changes in carbon credit relative value

4.5.5 Limitations

Some limitations for this analysis need to be considered to properly understand the results. First, the results are based on economic forecasts developed by the Canadian agencies, which rely on assumptions for inherently volatile items such as crude oil prices and current environmental policy. Higher crude oil prices could result in higher market growth, and technological advances could result in evaluated technologies being less costly than expected or certain subsectors growing more than expected. The sensitivity analysis conducted shows the impact of some of these results, but it is also important for the model to be updated as more information becomes available.

The methods used for predicting market penetration are based on market diffusion principles that assume new technologies follow a symmetric logit curve as they gain market share. Technologies generally follow this shape as they penetrate a market, reflecting slow initial uptake as they become better understood, followed by maximum penetration rates as the extent of the technology's applicability becomes known, and finally the slowing of penetration as the market becomes saturated. However, as an earlier study found, the assumption that technology penetration is symmetric cannot be validated with the level of data available [52]. More detailed market penetration models can be developed as more data on the technologies and market becomes available. The market penetration values are calculated based on new capacity requirements to meet the production growth forecast. This means that the potential for new technologies to be retrofitted onto an existing facility to replace aging equipment was not considered as data was not available to quantify the potential for this. The costs of such projects would also be different and unique to the project, making cost comparison difficult.

Emission regulations set by governing bodies also have a significant impact on the viability of new technologies, especially if the key advantage of a technology is to lower carbon emissions. Government policies are subject to change depending on the officials who are elected and the Canadian federal government's long-term carbon pricing policy, which is currently being challenged in court by several provinces. Additionally, current legislation results in some uncertainty around the exact value of the carbon credits received for operating under the emission benchmarks outlined in the taxation policy. This study addressed the uncertainty by using an estimated reduction in carbon credit value and performing sensitivity analysis on the chosen value; however, there is no publicly available data to determine the exact value of these credits.

Despite these limitations, the study results provide validated and applicable information for both private industry stakeholders and government policy makers for encouraging emission reductions.

4.6 Conclusion

This study reviewed and evaluated options for incorporating renewable energy technologies into oil sands processes. Using market penetration modelling and bottom-up energy accounting, ten different feasible renewable and low carbon energy technology scenarios across three different carbon pricing policies were assessed through the 2019-2050 time period. Penetration, GHG mitigation, and cost results from each scenario were compared to the reference scenario based on business-as-usual expected growth and the legislated oil sands 100 MT emission cap.

Under the highest carbon incentive policy (i.e. \$50/tonne of CO_2), 138 MT of cumulative GHG emission mitigation was available with an average cost of \$0.51/tCO_2e, showing near breakeven costs over the evaluation period. The most promising technology investigated was the use of small modular nuclear reactors for SAGD steam, with 98 MT of mitigation at -\$0.98/tCO_2e under the \$50/ tonne of CO_2 carbon incentive policy. The 100 MT emission cap was met through the evaluation period in the nuclear small modular reactor scenario under high carbon incentive scenario, and under low carbon incentive the same scenario delayed exceeding the cap by 6 years. Incorporating renewable energy technologies under current carbon incentives can result in industry GHG emissions remaining under the legislated cap using renewable and low carbon energy technologies, especially if multiple technologies are used. The analysis is highly sensitive to natural gas prices and the choice of IRR, so it is important to consider that the results are subject to change with changes to these key input variables.

The technology review and scenario results are of value to government policy makers and industry representatives for understanding the options available for low carbon technologies in the oil sands and the potential of specific technologies over a long-term planning horizon in order to focus sustainable development efforts.

5 Evaluating long-term greenhouse gas mitigation opportunities through carbon capture, utilization, and storage in the Canadian oil sands[2]

5.1 Introduction

Global oil production has been increasing over the last 20 years, with 2017 oil production 17% higher than it was in 2000 [99]. This trend is expected to continue with forecasts suggesting global oil demand will rise until at least 2030 [100]. Many countries around the world have agreed that carbon based emissions from the consumption of fossil fuels are causing detrimental effects to the planet and have agreed to reduce their emissions [3]. Emission data suggests that at least 65% of global carbon emissions are a result of producing and consuming fossil fuels such as crude oil [1]. Canada is home to the third largest proven oil reserves in the world known as the oil sands [67], but they are currently among the most energy intensive oil sources to produce [101]. Carbon capture, utilization, and storage technologies are currently the only option for gaining significant emission reductions while continuing to produce and consume fossil fuels [102] and could be used in the Canadian oil sector to reduce the carbon emissions from producing its vast oil resources.

In 2015 the Alberta (one of the provinces in Canada) oil sands contributed the largest share of greenhouse gas (GHG) emissions to Canada's oil and gas sector, 37%, and 10% to Canadian-wide GHG emissions [103]. The sector is thus one in which GHG emission intensity reductions would have a major impact on national GHG emission levels. The oil sands industry contributed 5% to the Canadian GDP in 2016 [21] and is expected to grow from 3,123 thousand barrels per day (kbpd) of crude bitumen in 2018 to 4,700 kbpd of crude bitumen in 2050 [13] and is thus a key

[2] A version of this chapter has been submitted for publication, titled: R. Janzen, M. Davis, A. Kumar, "Evaluating long-term greenhouse gas mitigation opportunities through carbon capture, utilization, and storage in the oil sands," Energy (Submitted), 2020.

aspect of the Canadian economy. Because of the economic importance and high GHG emissions of oil sands production, finding cost-effective GHG emission reduction strategies is an area of focus for industry and government, so much so that a firm GHG emissions cap has been imposed on the sector. These competing pressures have led to an urgency to lower the GHG emission intensities of oil sands processes while permitting industry growth and economic contribution, but doing so is a major challenge since most production requires large amounts of fossil fuels. Furthermore, in order to meet the targets of the Paris Agreement, immediate action must be taken to reduce GHG emissions [3].

The oil sands industry produces bitumen from oil sands formations in the northeastern part of the province of Alberta. Bitumen is a low hydrogen-to-carbon ratio product characterized by high viscosity and high density. It is extracted either through traditional surface mining techniques (when the product is within 80 m of the surface) or through in situ techniques (when the product is more than 150 m below surface) [10]. In situ techniques currently involve pumping steam underground to heat the oil sand and reduce bitumen viscosity so the bitumen can be pumped to the surface [16, 104]. Once the bitumen is extracted from either method, it is either diluted using hydrocarbon diluents, and the final product (dilbit) is shipped via pipeline or rail, or it is upgraded to the higher quality synthetic crude oil (SCO) through the addition of hydrogen (called upgrading) and then shipped [105, 106].

Oil sands operators currently use a combination of fossil fuels and electricity to meet the energy requirements for producing crude bitumen. Natural gas is the main energy source consumed and is used for process heat in surface mining extraction, steam generation for in situ production, combined steam and electricity in cogeneration plants, and hydrogen production in upgrading. The rate of natural gas consumption and the subsequent GHG emissions depend on the process and the mine characteristics. Without cogeneration, emissions from natural gas in surface mines range from 144 - 202 $kgCO_2e/m^3$ of bitumen produced, while in steam assisted gravity drainage (SAGD) facilities the range is 338 - 1052 $kgCO_2e/m^3$ [16]. Diesel fuel is also consumed for mobile mining equipment and electricity is used to power equipment and facilities in all processes and for some mobile mining equipment, contributing around 20 $kgCO_2e/m^3$ of crude bitumen produced. Due to the expected growth of the in situ sector and its high fossil-fuel use, in situ is predicted to be the main source of GHG emissions from the oil sands in the future [17].

Carbon capture, utilization, and storage (CCUS) technologies have been identified as the only option for substantially reducing GHG emission intensities while using fossil-fuel based processes [102]. The three stages involved in CCUS processes are capturing the CO_2, transporting it from the source to a suitable geological formation, and storing it in the formation. In some instances, it is possible to use the captured carbon during the storage process. CCUS technologies can be broken into three general categories: pre-combustion, post-combustion, and oxyfuel [107]. Pre-combustion technologies process fossil fuels into hydrogen and carbon dioxide streams, then capture the CO_2 and use the H_2 for energy. Post-combustion captures CO_2 after normal fuel combustion from the flue gas stream. This process is the simplest to retrofit into existing fossil fuel-based processes, but the CO_2 concentrations in the flue stream are typically low in conventional fuel combustion [108] because of the use of atmospheric air in the combustion process (0% - 10% concentrations in hot water and steam generation in the oil sands [109]). This results in the need for an expensive separation process involving a separation medium to remove the CO_2 from the flue gas stream, which usually accounts for around 80% of post-combustion capture and storage costs [108]. Oxyfuel processes attempt to deal with the CO_2 concentration issue by burning fossil fuels in high oxygen environments, resulting in higher CO_2 concentrations (typically 80% - 98%) [107]. The key challenge of this approach, which requires an air separation unit that adds to capital and operating expenses, is to produce oxygen at a scale necessary for many industrial processes. Post-combustion technologies are more mature than oxyfuel processes but have challenges with capture efficiency. Oxyfuel processes have high capture efficiency but are currently limited by the high energy requirements and costs of generating oxygen [107].

After capturing the carbon, it must be transported and stored. Transportation is the most mature aspect of CCUS technologies, and currently trucks, ships, and pipelines are used. Pipelines are the most economical for high-volume long-term projects [106, 110]. Storage, the third stage of CCUS, can be done in oil and gas fields, coal beds, or saline aquifers. These are all options in Alberta where favorable geological formations are available for saline aquifer storage [111] and an abundance of depleted oil wells suitable for CO_2 storage are also available [112]. Oil and gas fields can use captured CO_2 to pressurize reservoirs and increase oil production (known as enhanced oil recovery or EOR) or displace methane currently trapped in coal seams in existing coal beds; or the captured CO_2 can be pumped into aquifers that are suitable to hydrodynamically trap it [111]. In all cases, the captured carbon is stored; however, when captured CO_2 is used to pressurize oil wells or produce methane from coal beds, it has some commercial value (it can be used to produce saleable goods). This is the key difference between "utilization and storage" options and "storage" options. In cases where the captured CO_2 can be utilized and then stored, some value can be assigned to the captured carbon, improving the overall economics of potential projects. Sequestration sites must be analyzed before injection to ensure leakage will not occur [113] and monitored to verify that the injected CO_2 is staying in place. Many monitoring methods are available [107], but monitoring is critical, as even 0.1% leakage per annum would substantially reduce the climate benefit of the stored CO_2 [114].

Studies on the applicability of CCUS technologies in the Alberta oil sands have not analyzed their long-term GHG emission abatement potential. Ordorica-Garcia et al. conducted a study to identify the optimal carbon capture technology for each major oil sands process [38]. This study identified post-combustion capture for surface mines, oxyfuel boilers for in situ mines, and gasified bitumen (pre-combustion capture) for upgrading; however, the study lacked quantitative analysis of performance or cost of any of these options. Olateju and Kumar conducted techno-economic assessments of hydrogen production from underground coal gasification (UCG) with pre-combustion capture and of steam methane reforming (SMR) with post-combustion capture in Alberta [39]. This study estimated the costs of using CCS with SMR to be \$2.11-\$2.70/kg H_2 and CCS with UCG to be \$2.41/kg H_2 but did not determine the cost of mitigated GHG emissions or the GHG abatement potential. Verma and Kumar conducted a life cycle assessment of the carbon emissions from UCG with carbon capture in Alberta but did not perform economic analysis [40]. Verma et al. developed the marginal cost of GHG abatement for carbon capture applied to UCG and SMR in the two studies above and found that cost savings for reduced emissions were possible if the captured CO_2 could be sold to EOR operators and that UCG was the lowest cost mitigation option [41]. The long-term GHG abatement potential of each technology was not discussed in these studies. Bolea et al. developed the costs of using oxyfuel boilers with both natural gas and bitumen as fuel and found that bitumen-fueled oxyfuel boilers can be competitive with currently used once-through natural gas boilers [42]. However, this study only considered carbon capture costs, not transportation and storage, and did not determine the GHG emission abatement potential of the options considered. Key limitations in all of these studies are that year-to-year changes in operation costs based on expected changes in fuel prices are not accounted for and that a single value for the marginal cost of abatement is given. This is useful for determining the basic competitiveness of these technologies with what is currently used but does not allow cumulative abatement potential to be calculated over a long-term evaluation period. This is critical for long term decision making and policy formation.

Moreover, in studies of CCUS technologies, minimal consideration has been given to market penetration modeling. None of the studies discussed above considered the rate at which the CCUS technology being evaluated could enter the market. Ordorica-Garcia et al. conduct an optimization study by setting emission reduction targets and using linear optimization with several CCUS options to determine the lowest cost of achieving the targets [115]. This study found that GHG emissions could be reduced by 39% by implementing CCS with a 20% increase in production cost. Later, these same authors considered the costs of CCUS options based on the CO_2 concentration of the flue gas streams, again using linear optimization to determine the technology combination that offers the lowest capture cost at a particular concentration [109]. This study found that CCS costs almost tripled from high purity (>15% CO_2 concentration in flue stream) to low purity (<10% CO_2 concentration in flue stream) and that oil sands emissions are dominated by low purity sources. Also, this study identified gasification for hydrogen production in upgrading operations as the most promising technology. A key issue with linear optimization studies, however, is that they do not account for the rates at which technologies can feasibly enter markets. Rather, they assume that the lowest cost approach can immediately be applied in the period evaluated, which does not reflect how decisions are necessarily made in industry due to the different information available to private companies making investments, unique factors that impact site-by-site costs, and strategic plans unique to each organization [35]. Additionally, these studies do not consider any carbon utilization options, such as selling captured carbon to EOR operations and the impacts on GHG emission capture costs associated with that approach. It would be helpful to compare the results from these studies to a study using market penetration modeling and incorporate other technology options.

There is also no analysis in the literature of the long-term GHG emission abatement potential of using CCUS technologies in oil sands processes. This study performs an assessment of long-term GHG emission abatement from the use of CCUS in the oil sands and ranks the options in terms of marginal cost of GHG emission abatement. The study's novelty includes using a diffusion-based market penetration model to determine the penetration of each CCUS technology then evaluating the GHG emission impacts related to the use of those technologies in a bottom-up energy accounting model. The bottom-up energy accounting model in this study was developed as a continuation of the LEAP-Canada model developed previously [116]. The oil sands subsector of that model further developed for CCUS technologies and integrated with the market penetration model to give a comprehensive analysis of the market viability and GHG abatement potential of these technology options. CO_2 utilization and carbon pricing are also investigated for the first time in terms of how they affect the adoption and, in turn, the GHG emission abatement potential and marginal cost of each technology.

The purpose of this research is to investigate CCUS technologies for GHG emission abatement potential and marginal GHG abatement costs when used in oil sands processes. The results from the technology scenarios will provide industry and government decision makers with an outlook for the expected GHG emission reduction potential of CCUS technologies, associated costs, and impacts of different climate policies from the present day to 2050. The results will be achieved by the following study objectives:

- Create feasible technology scenarios under different carbon pricing policies for the implementation of CCUS technologies into oil sands processes in Alberta.

- Develop market penetration models to determine the rate CCUS technologies could enter the market.
- Use bottom-up energy modeling with integration of the market penetration model results to determine each technology's long-term GHG abatement potential and associated marginal costs over a planning horizon of 2020-2050.
- Assess 24 different GHG mitigation scenario through penetration of CCUS technologies in oil sands.
- Conduct a case study for Alberta, a western province in Canada

5.2 Methods

5.2.1 Study framework

This study evaluates CCUS technologies for use in the oil sands from 2019-2050. Figure 5-1 shows the study overview, providing the flow of data from inputs through modeling to the final output data. Scenario development, discussed in detail in Section 5.2.2, involves developing a reference scenario that reflects current practices and potential CCS and CCUS technology options that can replace technologies in specific processes in the reference scenario. Modeling work involves two key components. The market penetration model determines how quickly new technologies could gain market shares based on their projected costs and published market forecast data. The LEAP-Oil Sands model calculates energy use and subsequent GHG emissions in each scenario, using results from the market penetration model and published forecasts. These models and their respective inputs and outputs are discussed in Section 5.2.3. Results are provided in terms of a cost-benefit analysis, detailed in Section 5.2.4. Here, the GHG abatement potential and marginal costs of each scenario compared to the reference scenario are determined and the relative performances of CCS and CCUS technology options are compared.

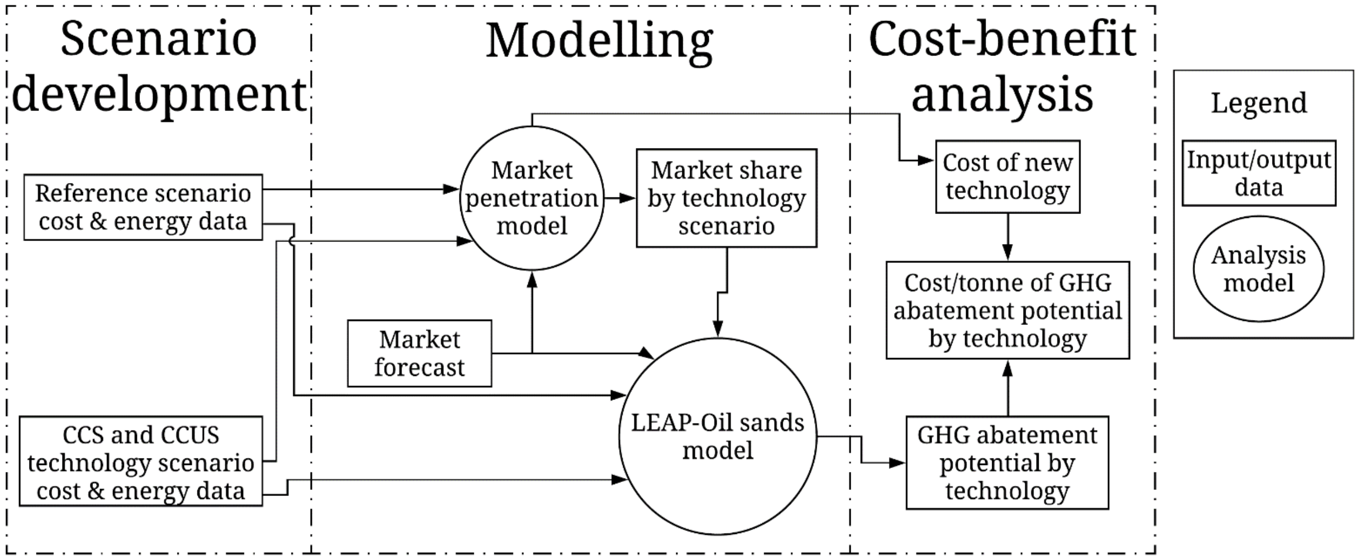


Figure 5-1: CCUS study framework

5.2.2 Scenario development

A reference scenario was developed to represent business-as-usual practices and serve as a baseline against which to compare alternative technology scenarios. The reference scenario considers currently used technologies in the oil sands, their energy and emission intensities, and their costs. An assumption is made in the reference scenario that currently used technologies and their respective energy intensities will be consistent through the evaluation period.

CCS and CCUS scenarios were developed by considering the feasible CCS technologies available to oil sands producers. Figure 5-2 shows the general pathways for producing bitumen from the oil sands including the three main subsectors of surface mining, in situ mining, and upgrading, as well as the range of concentrations of carbon in their process flue streams outlined in the literature [117]. Surface mining involves mobile mining equipment, for which current CCUS technologies cannot be used, and process heat for bitumen extraction. In situ production involves steam production through natural gas boilers. Current processes for process heat and steam generation have relatively low carbon concentrations. Upgrading consumes energy primarily through hydrogen production using steam methane reforming and hydrogen production processes have substantially higher concentrations of carbon in their flue streams. All of these subsectors also consume electricity to power various equipment and facilities; this electricity comes from either site cogeneration facilities or the Alberta grid.

A literature review on available CCUS technologies was conducted for these processes, and where techno-economic data on those technologies was available to allow for long-term modeling of the process, it was developed into a scenario for this study. There is insufficient data on pre-combustion carbon capture options for use in oil sands to develop any scenarios. A pre-combustion carbon capture study investigated options for decarbonizing natural gas feedstocks in Alberta and provided some supply cost estimates [118]. However, the cost of implementing these technologies was not provided in detail; more techno-economic data applied to oil sand's context is still needed in order to develop practical scenarios from these options. 2 post-combustion and 2 oxyfuel technology options were found to have sufficient data to allow for feasible scenario development in the oil sands in situ and upgrading sectors; these are shown in Figure 5-2. There is insufficient techno-economic data for CCUS integration into the surface mining subsector; thus, this sector was not considered. This subsector likely has not been the focus for CCUS due to the lower expected growth compared to in situ options and the higher difficulty of capturing GHG emissions from flue streams due to low and unrecoverable CO_2 concentrations, as shown in Figure 5-2.

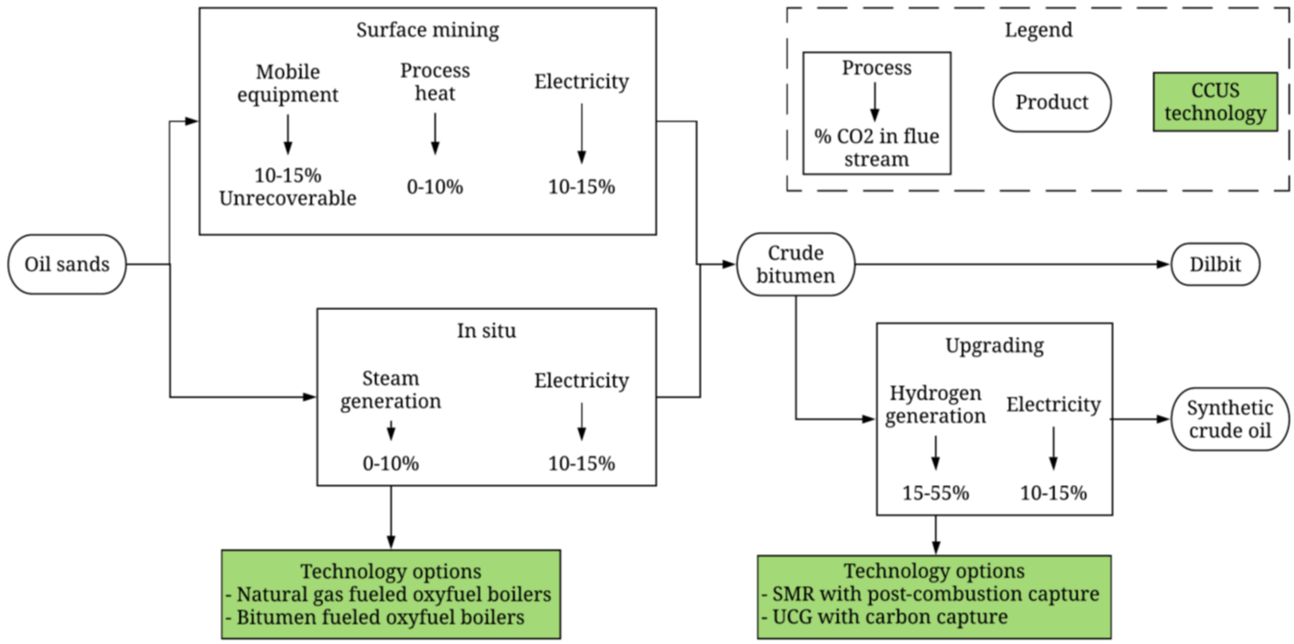


Figure 5-2: Overview of CO2 emission sources in oil sands processing and potential CCS technology applications (CO2 concentration in flue streams found in [109])

The 2 in situ technologies compete with current natural gas boiler steam generation and are both oxyfuel boilers in the SAGD subsector, one fueled by natural gas and the other by bitumen. The 2 upgrading technologies incorporate carbon capture into hydrogen generation for upgrading through post-combustion capture with SMR and through UCG with carbon capture. As Figure 5-2 shows, the SMR process has substantially higher CO_2 concentrations than other processes, making post-combustion capture possible [109]. The UCG plant involves gasifying underground coal to produce syngas. The syngas is processed to separate hydrogen, which is compressed and transported to upgraders, and CO_2, which is captured [39].

Each scenario's key metrics are outlined in Table 5-1. Costs for the upgrading and SAGD reference cases were calculated from overnight construction costs and estimated operating costs for facilities of average size for the industry [119]. In the evaluation of each technology, two options were considered for the disposition of captured CO_2: 1 – captured CO_2 is transported into saline aquifers and stored (CCS); 2 – captured CO_2 is transported and sold to EOR operators where it is used for oil recovery operations and permanently stored in the depleted oil reservoir (US).

Costs for carbon capture scenarios are based on the use of the technology for producing the required product and the lifetime costs associated with capturing, transporting, and storing (or utilizing and then storing) the emissions. The oxyfuel boiler scenarios (SAGD-OFNG-CCS, SAGD-OFBIT-CCS, SAGD-OFNG-CCUS, SAGD-OFBIT-CCUS) include the cost of an air separation unit for oxygen production, extra equipment for capturing and compressing the flue gas, and any heating value differences in the case of the bitumen fuel option [42]. Oxyfuel boiler costs associated with the operation of the boilers and the capture and compression of CO_2 at the site were based on techno-economic data taken from literature [42]. In order to account for the transportation and storage costs, the transportation and storage models developed in Verma et al. were adapted to the flow rates and transportation distances required in the oxyfuel boiler scenarios developed in this study [41]. The SMR plant with CCS scenario (H2-SMR-CCS) considers the additional cost of energy and equipment for incorporating post-combustion capture to currently used SMR processes for hydrogen production [41]. The UCG with CCS scenario (H2-UCG-CCS) considers the cost of producing and transporting hydrogen to upgrading sites as well as capturing and transporting GHG emissions [41]. For carbon utilization scenarios, the revenue from the sale of captured CO_2 was assumed to be \$47/tonne in 2020, which was previously identified as an acceptable market value [41].

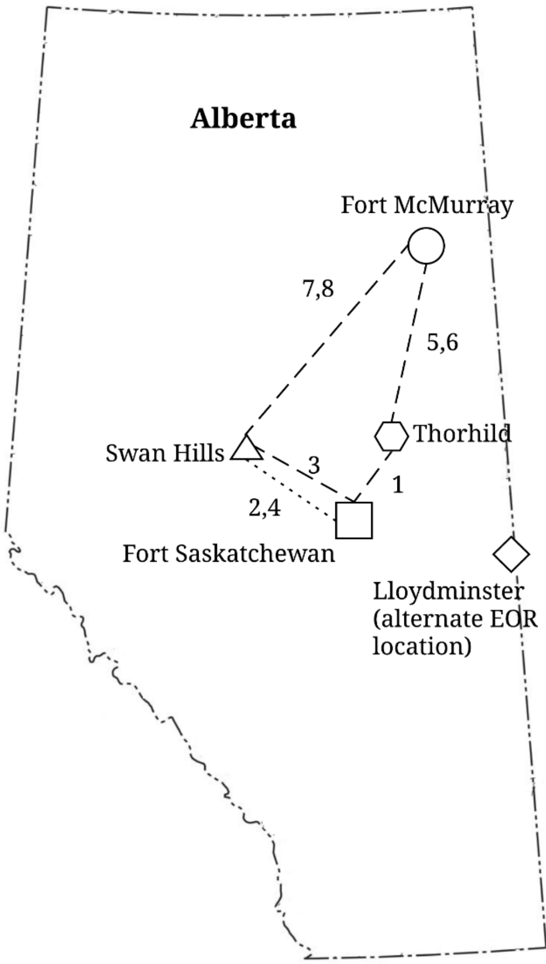
GHG emission factors for the reference case technologies are from the LEAP Technology and Environment Database that includes emission factors for major fuels [37]. GHG emission factors for CCUS technologies are based on the expected GHG emission intensity and capture efficiency of each process. They consider the parasitic energy required to operate the additional equipment needed and the energy needed for transportation and injection. GHG emission factors for the CCUS technologies considered in this study are based on the rate of capture presented in the techno-economic literature used to develop new technology scenarios and cited throughout this work.

Table 5-1: Key scenario information

Subsector	Scenario name	Description	Carbon transport location	Annualized cost* ($/kg H_2)	Emission factor (kg CO_2/kg H2)
Upgrading (hydrogen production)	Reference	Steam methane reforming (SMR)	Emitted to atmosphere	$1.41 + 0.15 \times P_{NG}$	8.47
	H2-SMR-CCS	Steam methane reforming with CO_2 storage	Aquifer storage	$1.69 + 0.15 \times P_{NG}$	2.98 [41]
	H2-UCG-CCS	Underground coal gasification with CO_2 storage	Aquifer storage	$2.63 + 0.40 \times P_{Coal}$	1.52 [41]
	H2-SMR-CCUS	Steam methane reforming with CO_2 enhanced oil recovery	Depleted oil wells	$1.55 + 0.15 \times P_{NG}$	2.98 [41]
	H2-UCG-CCUS	Underground coal gasification with CO_2 enhanced oil recovery	Depleted oil wells	$2.37 + 0.40 \times P_{Coal}$	1.52 [41]
SAGD (steam production)	Reference	Natural gas boilers	Emitted to atmosphere	$21.67 + 1.12 \times P_{NG}$	60.4
	SAGD-OFNG-CCS	Natural gas oxyfuel boilers with CO_2 storage	Aquifer storage	$24.75 + 1.13 \times P_{NG} + 4.7 \times P_{ELEC}$	6.0 [42]
	SAGD-OFBIT-CCS	Bitumen oxyfuel boilers with CO_2 storage	Aquifer storage	$25.12 + 1.54 \times P_{BIT} + 4.7 \times P_{ELEC}$	12.1 [42]
	SAGD-OFNG-CCUS	Natural gas oxyfuel boilers with CO_2 enhanced oil recovery	Depleted oil wells	$21.59 + 1.13 \times P_{NG} + 4.7 \times P_{ELEC}$	6.0 [42]
	SAGD-OFBIT-CCUS	Bitumen oxyfuel boilers with CO_2 enhanced oil recovery	Depleted oil wells	$22.24 + 1.54 \times P_{BIT} + 4.7 \times P_{ELEC}$	12.1 [42]

*Detailed information about the development of these values is provided in Table 5-3. P_{NG} = price of natural gas ($/GJ); P_{COAL} = price of coal ($/tonne); P_{BIT} = price of bitumen ($/GJ); P_{ELEC} = price of electricity ($/kWh)

The geographical location of commodity production, use, and storage is an important factor in the costs and practicalility of each scenario. Figure 5-3 shows this information for each scenario, highlighting the location of the carbon source, sequestration site, and required major pipelines. The associated costs of the required pipelines are considered in each scenario. Current scenario costs are based on carbon utilization scenarios selling captured CO_2 to EOR operators in the Swan Hills area; however, recent reports have suggested that Lloydminster, Alberta may also be an optimal area for these operations [120]. Differences in transportation distances from Fort Saskatchewan or Fort McMurray to either location were analyzed and considered negligible. The cost to implement the scenarios in both locations would be similar.



#	Scenario	Production location	Sequestration location	Transport method
1	H2-SMR-CCS	Fort Saskatchewan	Thorhild	CO2 Pipeline
2	H2-UCG-CCS	Swan Hills	Swan Hills	H2 Pipeline
3	H2-SMR-CCUS	Fort Saskatchewan	Swan Hills	CO2 Pipeline
4	H2-UCG-CCUS	Swan Hills	Swan Hills	H2 Pipeline
5	SAGD-OFNG-CCS	Fort McMurray	Thorhild	CO2 Pipeline
6	SAGD-OFBIT-CCS	Fort McMurray	Thorhild	H2 Pipeline
7	SAGD-OFNG-CCUS	Fort McMurray	Swan Hills	CO2 Pipeline
8	SAGD-OFBIT-CCUS	Fort McMurray	Swan Hills	CO2 Pipeline

Figure 5-3: Overview of scenario locations and captured carbon or produced hydrogen transportation methods (map taken from NRCan and used in accordance with the Canadian Open Government License [97])

Each scenario is also considered under three different carbon taxation policies. First, scenarios are considered in the absence of any carbon pricing to allow for a clear comparison of cost performance without regard to emissions. Second, a price of \$30/tCO_2 is applied [95]. Third, a price of \$30/tCO_2 is applied until 2020, is increased to \$40/tCO_2 in 2021, to \$50/tCO_2 in 2022, and remains static for the remainder of the evaluation period. This final option follows the Pan-Canadian Framework proposed by the federal government [4]. Emissions above the given benchmark are taxable and GHG emissions below the given benchmarks are subject to credits equivalent to the taxation rate. Table 5-2 below provides the emission benchmarks for industries considered in this study.

Table 5-2: Taxable GHG emissions benchmark values [8]

	BE_y: Established benchmark for year *y* (tCO_2e per product unit)						
Product	**2018**	**2019**	**2020**	**2021**	**2022**	**Subsequent years**	**Product unit**
Hydrogen	7.97	7.97	7.89	7.81	7.73	$BE = BE_{y-1} - 0.08$	Tonne
Oil sands in situ bitumen	0.3504	0.3504	0.3469	0.3434	0.3399	$BE = BE_{y-1} - 0.0035$	m^3 bitumen

Scenario names are used to differentiate the carbon pricing options being evaluated. The zero carbon price scheme is indicated by "CP0" added to the scenario name, "CP30" is added for the scheme reaching $30/$tCO_2$, and "CP50" indicates the scheme reaching $50/$tCO_2$.

5.2.3 Modeling

5.2.3.1 Market penetration

The rate at which a prospective technology can feasibly enter the market is determined through market penetration modeling using the costs of the prospective technology and the currently used technology. Several methods exist to assess technology market penetration. For technologies that have been demonstrated but have little existing market penetration, cost and diffusion modeling are useful approaches [52]. Technology diffusion involves assigning market share based on a logit curve that represents the assumption that technology uptake is slow both early on and when the technology has become saturated but is quick in the intervening period. An earlier study presents an equation for calculating annual market share of technologies based on technology lifetime cost shown in Equation 5-1 [57]:

$$\mathrm{MS_j} = \frac{\mathrm{LCC_j^{-v}}}{\sum_{j=1}^{k} \mathrm{LCC_j^{-v}}} \tag{5-1}$$

where MS_j is the market share of technology j in the examined year, LCC_j is the annualized lifetime cost of technology j in the examined year, v is the cost variance parameter discussed in more detail below, and k is the number of competing technologies in the subsector being examined. The cost variance parameter is included to represent market research showing that decision makers do not always choose the cheapest technology but may select a more expensive technology for a variety of reasons such as long-term outlook of the technology. For the energy industry, a range of 6 to 10 is considered appropriate [35]. In this study a value of 8 is used and sensitivity analysis is conducted over the entire range consider appropriate in the literature [35].

The annualized lifetime cost is developed so that a year-by-year cost per unit of production for each technology is determined using all the major cost components of that technology. This value is calculated by adapting equation proposed in literature [57] to oil sands costs:

$$\mathrm{LCC_j} = \left(\mathrm{CC_j} \times \frac{\mathrm{i}}{1-(1+\mathrm{i})^{-\mathrm{n}}}\right) + \mathrm{OC_j} + \mathrm{ECC_j} + \mathrm{EC_j} \tag{5-2}$$

In our Equation 5-2, CC_j is the overnight capital cost of technology j, i is the interest rate, n is the technology lifetime, OC_j is the annual operating and maintenance costs of technology j, ECC_j is the annual cost of emitted carbon for technology j calculated using the emission benchmarks in Table 5-2 and the carbon price, and EC_j is the annual energy cost for technology j. Technology costs are evaluated using an internal rate of return (IRR) of 10% for the interest rate and converting all dollars to 2020 $CAD. IRR selections are variable and based on the perceived risk of the technology; we used 10%, as found in earlier studies for new technologies [28, 94]. Sensitivity analysis was also conducted on the value.

Annual market share results from Equation 5-1 are multiplied by the forecasted new production in the considered subsector to calculate the new production each year from every considered technology, based on the production forecasts shown in Figure 5-4. The production forecasts up to 2040 are taken directly from LEAP-Canada model and are in line with the Canadian National Energy Board (NEB) [13]. Production beyond 2040 was determined by extrapolation using each subsector's growth between 2030 and 2040 using the LEAP-Canada model. New production available for CCUS technologies is the difference between the forecasted production in the evaluation year and the forecasted production from the previous year. The calculated market share for each technology is used to determine what share of the production increase in each year is assigned to each technology. If there is no production increase in that year, then there is no change in market share for the technologies.

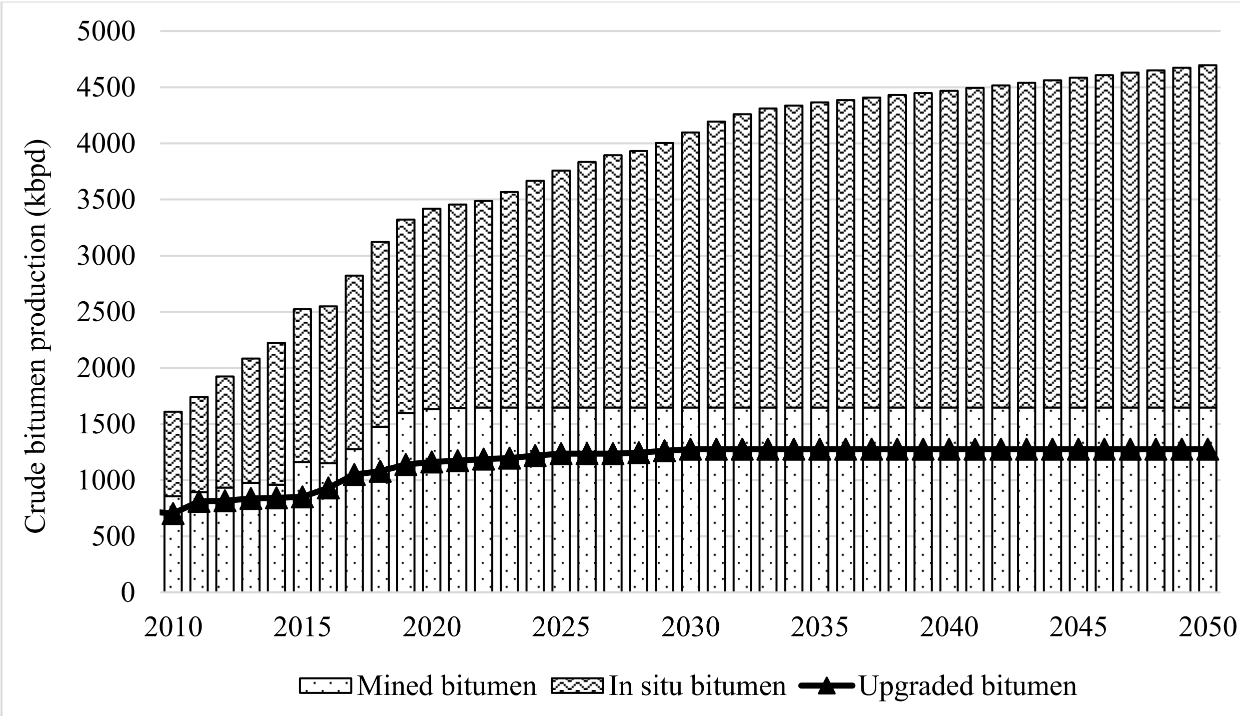


Figure 5-4: Relevant subsector production forecasts entered into the LEAP-Oil sands model

In situ scenario costs are based on earlier studies for facilities from production rates of 30 to 100 kbpd. Currently active commercial SAGD facilities range from 1.5 to 180 kbpd with an average of 48 kbpd in 2019 [121]. Expected production growth in the SAGD subsector is 20 million barrels/year from 2020 to 2040 [13], suggesting ample room for new technologies to penetrate the market. Thus, no size constraints for technology adoption were applied.

The upgrading subsector has a lower rate of expected growth of 196 kbpd from 2020 to 2040 [13], an 18% capacity increase. The additional hydrogen required to meet the increased production would be approximately 670 tonnes H_2/day. Since the CCUS technology facility sizes considered in this study are 607 and 660 tonnes H_2/day for SMR and UCG plants [41], respectively, the forecasted growth allows for upgrading with CCUS to be considered in this study. There is also the potential for bitumen upgrading to grow beyond the NEB forecasts as there are currently interest and financial incentives for alternative upgrading options in Alberta that would require additional hydrogen if successful [122, 123]. Therefore, despite the lower forecasted growth of the upgrading subsector, there is value in investigating technology options in it. The potential to implement CCUS technologies at existing facilities was not considered due to the lack of available economic data and the range of facility sizes currently operating. New growth offers the most cost-effective implementation pathway for new technologies (because the additional capital costs can be somewhat absorbed into the construction activities of the new facility) and is the focus of the present work. Input costs for Equation 5-2 developed from earlier studies for each scenario are shown in Table 5-3.

Table 5-3: Key input data for Equation 5-1 by technology

Technology	CC	OC	ECC	EC*	Units	Lifetime (years)	Source
Reference – Bitumen upgrading	1.14	0.27	0.008	$0.15*P_{NG}$	\$/kg H_2	20	[41]
H2-SMR-CCS	1.37	0.32	0.003	$0.15*P_{NG}$	\$/kg H_2	20	[41]
H2-UCG-CCS	2.25	0.38	0.002	0	\$/kg H_2	20	[41]
H2-SMR-CCUS	1.26	0.3	0.003	$0.15*P_{NG}$	\$/kg H_2	20	[41]
H2-UCG-CCUS	2.01	0.36	0.002	0	\$/kg H_2	20	[41]
Reference - SAGD	13.02	8.64	0.056	$1.12*P_{NG}$	\$/bbl	20	[119]
SAGD-OFNG-CCS	16.11	8.64	0.006	$1.13*P_{NG}$	\$/bbl	20	[42]
SAGD-OFBIT-CCS	16.47	8.64	0.012	$1.54*P_{BIT}$	\$/bbl	20	[42]
SAGD-OFNG-CCUS	15.5	6.09	0.006	$1.13*P_{NG}$	\$/bbl	20	[42]
SAGD-OFBIT-CCUS	15.87	6.37	0.012	$1.54*P_{BIT}$	\$/bbl	20	[42]

*P_{NG} = price of natural gas; P_{BIT} = price of fuels derived from produced bitumen (approximated as 1/3 of natural gas price [42])

5.2.3.2 LEAP-Oil sands model

Long-range Energy Alternatives Planning (LEAP) model [37] was used to develop an energy and GHG emission accounting model for the oil sands (LEAP-Oil sands) and to determine the emission reduction potential of the technology scenarios. The LEAP-Oil sands model was developed and validated as part of previous research [64, 70]. Validation included comparing the LEAP-Oil sands model results to publicly available energy consumption values provided by the Canadian Energy Research Institute [124], which were within 1% of reported values, and GHG emissions values from Environment and Climate Change Canada [6], which were within 2% of reported values. The model is structured into demand and transformation modules. The demand module includes the energy-consuming technologies used for oil sands production, with their energy intensities (energy required per barrel of production activity) and fuel types defined. The energy requirements calculated in the demand module are met from the transformation module, where energy sources and conversion processes are defined in the model. The model is driven by production forecasts with the latest production forecasts published by the NEB [13]; the relevant subsector data, shown in Figure 5-4, gives total production from the surface mining and in situ subsectors (the two combined gives total oil sands production) and the portion of product upgraded. Intergovernmental Panel on Climate Change (IPCC) and user-defined GHG emission factors are used for the specific fuels consumed in the oil sands to calculate GHG emissions. Emission factors for existing technologies are based on the values provided in LEAP's Technology and Environmental Database, which applies IPCC emission factors from the Fifth Assessment Report [1]. For a more detailed breakdown of the model structure, assumptions, and function see Katta et al. [12].

The structure of the LEAP-Oil sands model described in Katta et al. [12] is shown below in Table 5-4. This model was updated in this study to include the 8 technology scenarios that consider the replacement of current SAGD and upgrading subsector technologies with CCS and CCUS options. In the SAGD branch of the model, oxyfuel boilers fueled by bitumen and natural gas are added, along with their emission factors from Table 5-3, to compete with non-CCUS steam generation. In the upgrading branch of the model, SMR equipped with carbon capture and UCG with carbon capture are added along with their emission factors from Table 5-3, to compete with non-CCUS SMR operations. The activity levels of the competing technologies were determined by the market share model results that were input to the LEAP-Oil sands model.

Table 5-4: LEAP-Oil sands model structure

Sub sector	Surface mining	
Technology	Pumping (steam, bitumen, and tailings)	
	Conveyor belts for slurry transport	
	Power shovels	
	Crushing	
	Mixing	
	Flotation	
	Air compression	
	Steam generation	
	Raw bitumen transport	
Sub sector	**In situ mining**	
Technology	Steam pumps	
	Compressors	
	Mixers	
	Process heat	
Sub sector	**Upgrading**	
Process	**LC fining & hydrotreatment**	**Coking & hydrotreatment**
Technology	Distillation	Crude distillation
	Residue hydroconversion with integrated hydrotreatment	Vacuum distillation
	Sulphur recovery	Gasoil hydrotreater
	Hydrogen generation	Other hydrotreatment
	Solvent deasphalting	Hydrogen generation
	Steam generation	Coking unit
	Other utilities	Steam generation
		Sulphur plant
		Other utilities

5.2.4 Cost-benefit analysis

The results from the LEAP-Oil sands model and the market penetration model are combined to develop marginal GHG abatement cost curves for each scenario, which provide the GHG emission abatement potential and marginal cost of GHG abatement for each scenario.

Equation 5-3 is used to calculate the cost of mitigation in each scenario using the GHG emission quantities from LEAP-Oil sands and the costs calculated in the market penetration model.

$$Scenario_x\ marginal\ cost\ [\$/tonne] = \sum_{n=i}^{n} \frac{SC_{xn} - SC_{BAUn}}{SE_{BAUn} - SE_{xn}} \tag{5-3}$$

In the equation, $Scenario_x\ marginal\ cost$ is the cost per tonne of CO_2 equivalent for scenario x, SC_{xn} is the annualized cost of using technology x per unit produced in year n, SC_{BAUn} is the annualized cost of using the business-as-usual technology per unit produced in year n, SE_{BAUn} is the GHG emissions from using the business-as-usual technology in year n, and SE_{xn} is the GHG emissions from using the technology x in year n. The results are summed for the entire evaluation period (2020-2050) for a cumulative cost of mitigation for each scenario. Future scenario costs are discounted at a rate of 5% to 2020 dollars based on earlier studies for GHG mitigation [28].

5.2.5 Sensitivity analysis

Sensitivity analysis was conducted on key variables that are subject to variation and influence results in order to examine the factors that most impact the results of this work. The cost variance parameter used in Equation 5-1 was changed over the range applicable to the energy industry (6 to 10) and the resulting changes in technology market shares were recorded. Carbon credits changes with availability and demand. Average values of how much less credits are typically traded for are not publicly available. For that reason, the assumed market value of 85% of the taxation rate is changed by +/- 10% to determine the effect on results. Natural gas prices have historically varied considerably in North America and have a significant impact on the costs of operating the business-as-usual technologies; therefore, technology penetration and cost of GHG mitigation results were tested for prices +/- 20% of forecasted values, roughly matching the ranges in the "high price"/"low price" scenarios provided by the Alberta Energy Regulator [20]. Forecasted market growth depends on many factors, including the global price of oil, infrastructure for shipping product, and government policy for new project approvals; therefore, the results were tested for changes of +/- 20% in growth projections, roughly matching the "low growth" and "high growth" scenarios provided by the NEB [13]. Finally, the results were recorded with IRRs of +/- 5% to cover general IRR values used for low- and high-risk technologies and determine the impact of internal policies and perceived risk of new technologies on their market potential.

5.3 Results and discussion

5.3.1 Market penetration

The 2050 market share results from the market penetration model are shown for carbon storage scenarios in the upper portion of Figure 5-5. Technologies consistently achieve higher market shares with increased carbon pricing; however, the increase from no carbon pricing to CP30 is more significant than the difference between CP30 and CP50. The highest performing scenario was oxyfuel bitumen boilers (SAGD-OFBIT-CCS); the technology achieved market shares of 17.6% with CP0, 21.1% with CP30, and 23.1% with CP50. The high penetration resulted from two factors; the improved operating costs from lower-cost fuel as the natural gas price increased over time and the relatively similar capital costs compared to the reference scenario. Oxyfuel natural gas boilers (SAGD-OFNG-CCS) achieved significant market share, though lower than the bitumen-fueled option. Market shares were 9.4% with CP0, 11.6% with CP30, and 12.8% with CP50. The highest potential penetration in the SAGD subsector was 58%, with the top performing scenario capturing 40% of the available growth. The lower market shares are due to the higher forecasted cost of oxyfuel boilers fueled by natural gas as natural gas prices increase.

Hydrogen-producing scenarios generally achieved lower market shares than technologies in the SAGD sector because of lower expected growth in the upgrading sector, where the highest potential penetration in the upgrading subsector was 18% (because of the lower growth expected in the subsector). SMR with CCS (H2-SMR-CCS) gained 4.3%, 6.2%, and 6.8% market shares for CP0, CP30, and CP50 scenarios, respectively, while UCG with CCS (H2-UCG-CCS) gained 1.3%, 1.9%, and 2.3% market shares for CP0, CP30, and CP50 scenarios, respectively. The top performing scenario in the upgrading sector (H2-SMR-CCS-CP50) captured 38% of the available market growth. In these scenarios, the additional cost of UCG facilities and the additional transportation distance of captured CO_2 to the sequestration site contributed to the lower cost competitiveness of UCG options. The expected increases to natural gas prices were not significant enough to make UCG cheaper than SMR in these scenarios. Additionally, the limited forecasted growth of the upgrading subsector restricted the market share available to be gained by both UCG and SMR technologies, and the large size of a new SMR or UCG plant may restrict the feasibility of implementing these scenarios unless similar costs can be achieved with scaled-down facilities.

Scenarios considering the utilization of captured CO_2 for EOR operations offered a revenue stream for captured carbon, thereby reducing costs. Reduced costs from the sale of captured CO_2 resulted in increased 2050 market shares for every scenario, as shown in Figure 5-5. Again, the top performing technology was the bitumen-fueled oxyfuel boiler used for SAGD steam, represented by the SAGD-OFBIT-CCUS scenarios. Market share results for this technology were 25% for CP0, 27% for CP30, and 30% for CP50. For these options, the top performing scenario captured 52% of the available growth.

For hydrogen options, SMR again outperformed UCG options, gaining 5.5%, 7.3%, and 8.5% market shares under no carbon cost, CP30, and CP50, respectively. Here, H2-SMR-CP50-CCUS gained 47% of the available market growth. These were more than double the market shares achieved by UCG. Although it is the highest performing scenario in the upgrading subsector, it represents a facility of only 315 tonnes H_2/day, while the optimal facility size, based on earlier studies, is a 607 tonnes H_2/day [41]. Because of the large facility size, limited forecasted growth in the upgrading subsector, and the resulting lower market shares, the feasible implementation of the upgrading subsector scenarios may be limited. In all the carbon utilization scenarios, carbon pricing had a smaller impact on market share results than when carbon was captured for storage.

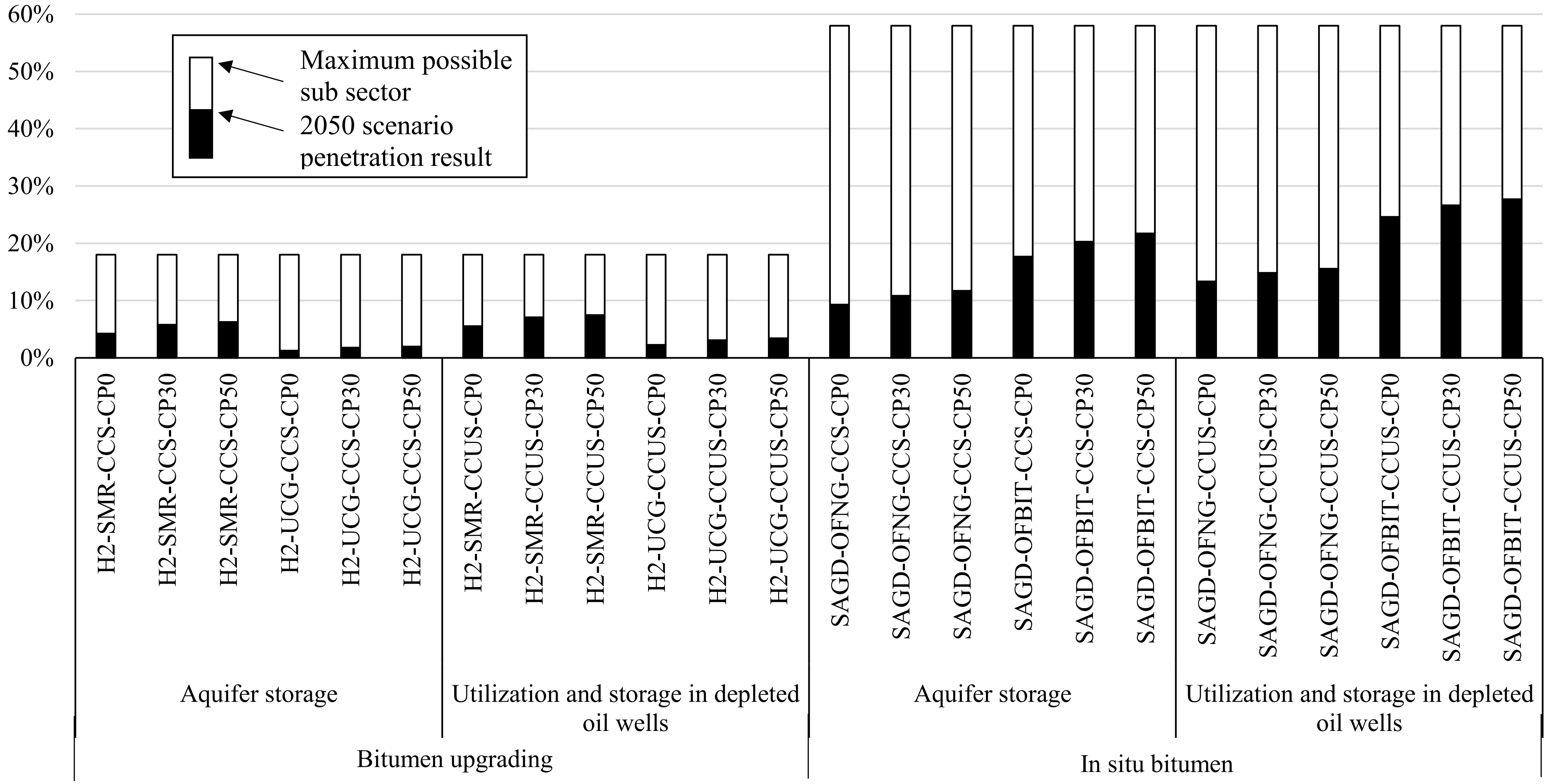


Figure 5-5: 2050 market share results for scenarios with respect to maximum subsector penetration

5.3.2 GHG abatement potential

Combining the top aquifer storage (CCS) scenarios from both sub sectors resulted in 157 Mt, 183 Mt, and 196 Mt of GHG abatement potential by 2050 for the CP0, CP30, and CP50 carbon pricing, respectively. These results translate to maximum reductions of 4.5%, 5.2%, and 5.6% of industry-wide GHG emissions during the evaluation period, respectively, depending on the carbon price. Carbon pricing resulted in an additional 26 Mt of abatement potential for CP30 and 39 Mt for CP50. If the results are similarly added for the top carbon utilization scenarios (CCUS scenarios), the results are 215 Mt, 236 Mt, and 245 Mt of GHG abatement potential by 2050, or 6.1%, 6.7%, and 7.0% reductions for CP0, CP30, and CP50 scenarios, respectively. These results show that the option to gain revenue from captured CO_2 increases the viability of these technology options significantly, providing a 1.5% increase in abatement potential on average. Carbon pricing resulted in an additional 21 Mt of abatement potential for CP30 and 30 Mt for CP50.

Annual GHG abatement potential from each scenario was calculated, and results from the CP30 scenarios are shown in Figure 5-6. The top performing technology was bitumen-fueled oxyfuel boiler for SAGD steam (SAGD-OFBIT), providing 170 Mt and 225 Mt of abatement potential in the carbon storage and carbon utilization scenarios, respectively. The highest performing upgrading technology was steam methane reforming with carbon capture, which provided 11 Mt and 13 Mt of abatement potential in the carbon storage and carbon utilization scenarios, respectively.

CP30 scenario results were adjusted to consider only the sources applicable to the legislated 100 Mt GHG emissions cap and are shown in Figure 5-6, to allow for comparison to the cap. Scenarios incorporating upgrading technologies are not considered here because upgraders constructed or expanded after 2015 are excluded from the cap. The reference case is expected to exceed the GHG emission cap in 2041, and all four scenarios incorporating carbon capture into SAGD are expected to provide GHG emission abatement significant enough to keep the industry below the emission cap. SAGD-OFBIT-CCUS performed the best, with 2050 emissions reaching only 93.7 Mt. SAGD-OFNG-CCS provided the lowest abatement potential, and 2050 emission levels are projected to be 99.7 Mt in 2050 and expected to exceed the emission cap if the industry continues to grow.

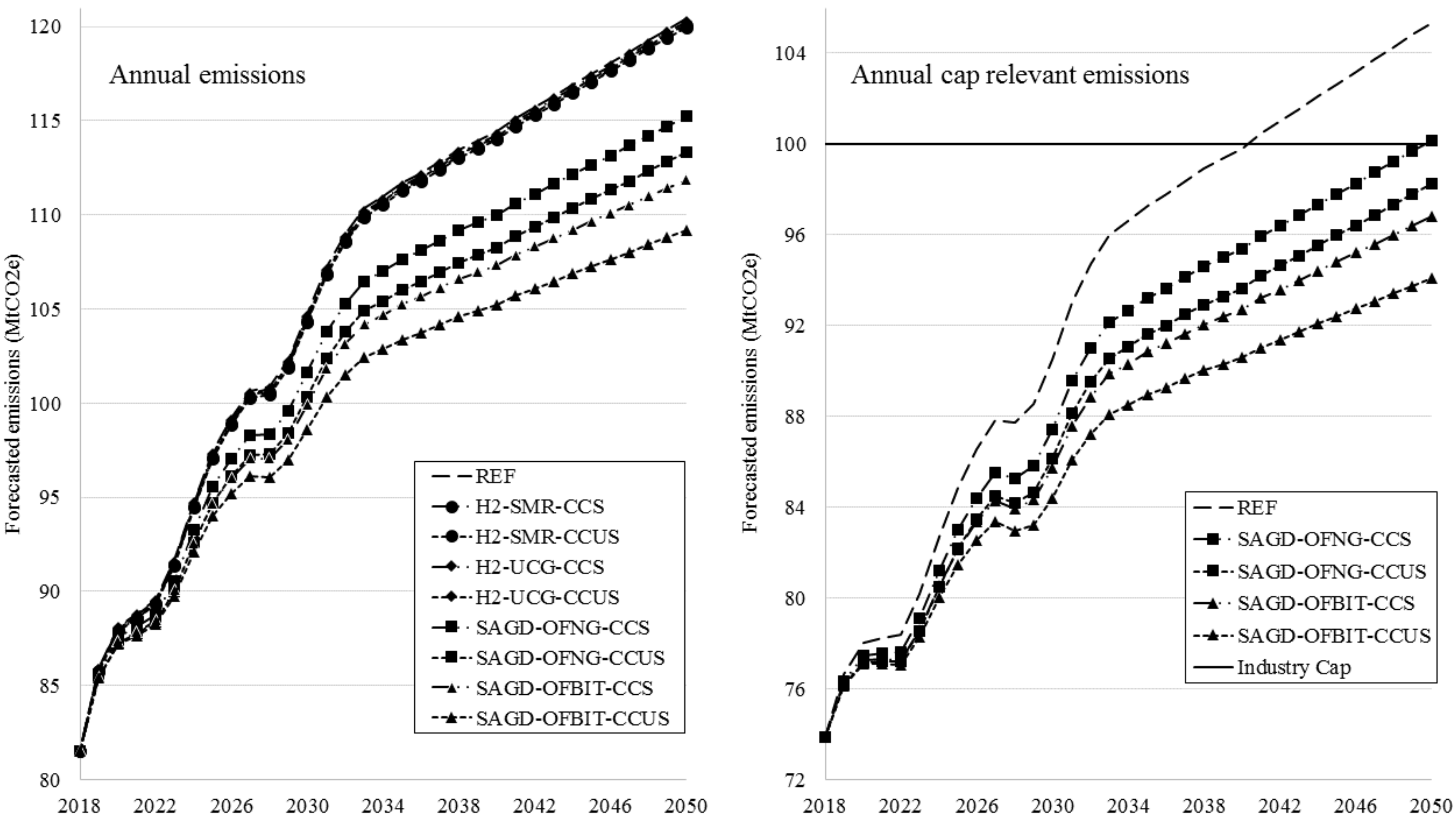
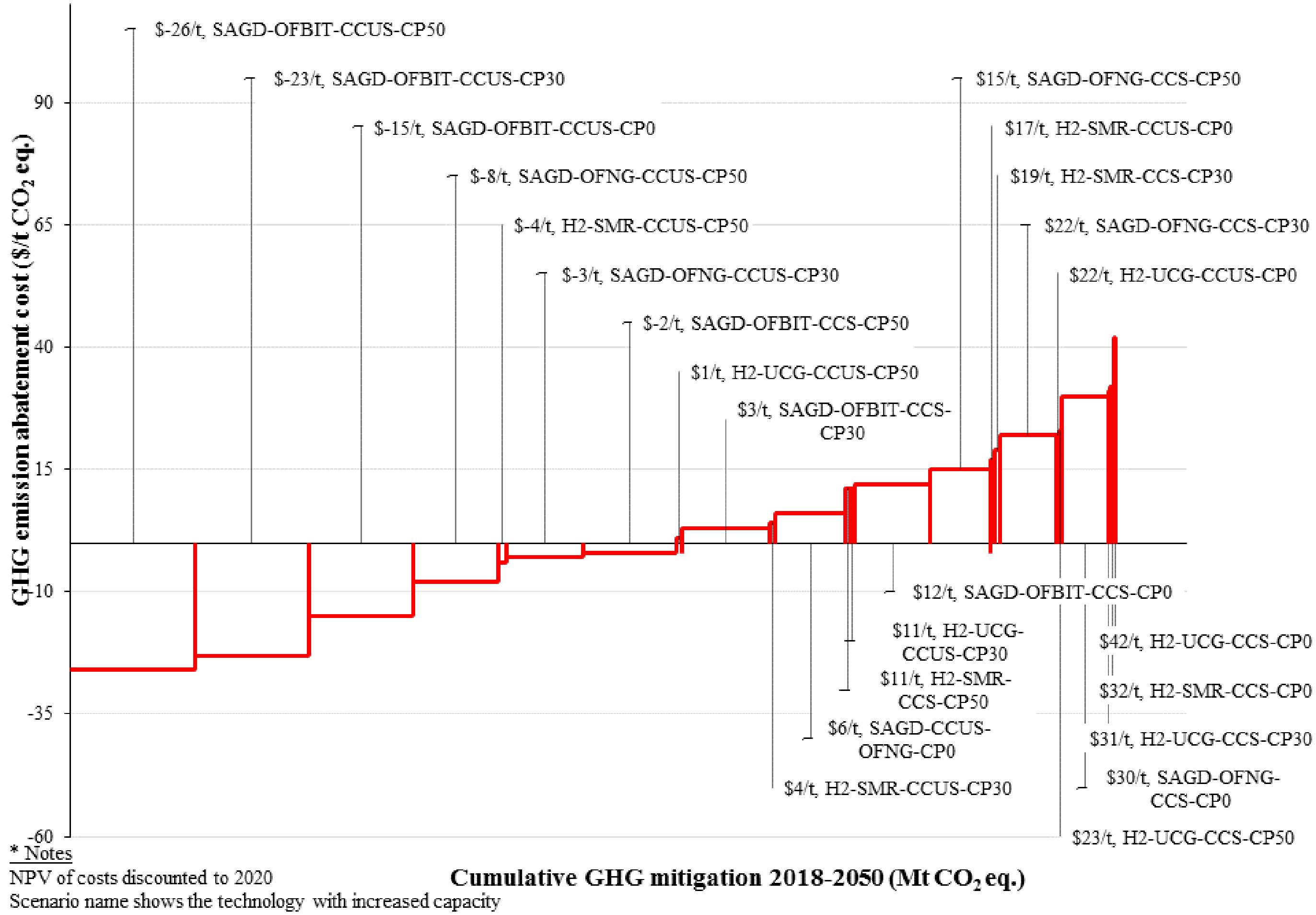


Figure 5-6: Annual emission results for CP30 scenarios

5.3.3 Cost-benefit analysis

The marginal cost of GHG emission mitigation for each scenario is presented in the cost curve in Figure 5-7. The marginal costs are discounted at a rate of 5% to give a net present value (NPV) of the scenario in the first year of evaluation (2020). For each scenario in the cost curve there is a rectangle whose width represents the potential GHG abatement available in the scenario and whose height represents the cost of mitigation. The scenarios are organized by cost from left (lowest) to right (highest), and scenarios that show negative costs indicate that selecting that scenario would result in cost savings over the evaluation period. The table on the right-hand side of the figure provides the total mitigation by scenario and the percent of all the GHG mitigation available for each scenario.



Scenario	Mitigation (Mt)	%
SAGD-OFBIT-CCUS-CP50	246	11.9
SAGD-OFBIT-CCUS-CP30	223	10.8
SAGD-OFBIT-CCUS-CP0	205	10
SAGD-OFNG-CCUS-CP50	169	8.2
H2-SMR-CCUS-CP50	15	0.7
SAGD-OFBIT-CCS-CP50	185	9
SAGD-OFNG-CCUS-CP30	152	7.4
H2-UCG-CCUS-CP50	9	0.4
SAGD-OFBIT-CCS-CP30	173	8.4
H2-SMR-CCUS-CP30	13	0.6
SAGD-OFNG-CCUS-CP0	136	6.6
H2-SMR-CCS-CP50	11	0.5
H2-UCG-CCUS-CP30	8	0.4
SAGD-OFBIT-CCS-CP0	150	7.3
SAGD-OFNG-CCS-CP50	117	5.7
H2-SMR-CCS-CP30	11	0.5
H2-SMR-CCUS-CP0	10	0.5
SAGD-OFNG-CCS-CP30	109	5.3
H2-UCG-CCS-CP50	5	0.2
H2-UCG-CCUS-CP0	6	0.3
H2-UCG-CCS-CP30	4	0.2
SAGD-OFNG-CCS-CP0	92	4.5
H2-SMR-CCS-CP0	8	0.4
H2-UCG-CCS-CP0	3	0.1

Figure 5-7: GHG mitigation cost curve to 2050

The three top performing scenarios were SAGD-OFBIT-CCUS-CP50, SAGD-OFBIT-CCUS-CP30, and SAGD-OFBIT-CCUS-CP0 with 253 Mt of abatement potential at -\$30/tCO_2e, 225 Mt of abatement potential at -\$24/tCO_2e, and 205 Mt of abatement potential at -\$15/tCO_2e, respectively. Negative abatement costs indicate that cost savings are forecasted in the associated technology scenario. The results show that the strongest financial performance came from the same technology, oxyfuel boilers using bitumen fuel for SAGD steam, and also that, regardless of the carbon tax policy, all scenarios resulted in cost savings. For comparison, SAGD-OFBIT-CCS-CP30 resulted in 170 Mt abatement potential at -\$4/tCO_2e, a \$20/tCO_2e cost increase, and a 55 Mt decrease in GHG abatement potential. This difference represents the effect of the ability to sell captured CO_2 rather than simply storing it. In the upgrading subsector, H2-SMR-CCUS-CP50 was the top performing scenario and resulted in 15 Mt of GHG abatement potential at -\$7/tCO_2e. Scenarios in the upgrading subsector where captured carbon was stored and no carbon price was applied performed the most poorly in both abatement potential and marginal GHG abatement cost. H2-UCG-CCS and H2-SMR-CCS were limited to 3 Mt at \$42/tCO_2e and 8 Mt at \$32/tCO_2e, respectively, because of the low expected growth in the subsector and the lack of financial benefit (either through the sale of captured carbon or carbon pricing policies). SAGD-OFNG-CCS suffered similarly high costs at \$30/tCO_2e, but still had relatively strong abatement potential at 94 Mt due to the high expected growth in the in situ subsector.

Research by Katta et al. into other GHG abatement opportunities for the oil sands gives insight into where CCUS options stand in terms of cost-effectiveness and abatement potential. Energy efficiency options from the Katta et al. study evaluated under policy conditions similar to CP50 scenarios in our study show that the in situ sector could provide an abatement potential of 165 Mt at -\$70/tCO_2e by 2050 [12]. In the same study, the upgrading sector was found to have 49 Mt at -

$145/tCO$_2$e by 2050 [12]. These results show that the cost-effectiveness of energy efficiency options may be superior to CCUS options, and if used in conjunction with each other could provide substantially more abatement potential for the oil sands industry.

5.3.4 Sensitivity analysis

The sensitivity analysis results presented here are from the CP30 carbon pricing policy. Sensitivity trends were found to be similar regardless of the carbon pricing. The cost variance parameter was changed from 6 to 10 and the resulting 2050 market share results are given in Figure 5-8. SAGD-OFBIT-CCUS-CP30, SAGD-OFBIT-CCS-CP30, and H2-SMR-CCUS-CP30 all gained market shares as the cost variance parameter increased, while the remaining scenarios showed a decreasing trend. Scenarios with increasing trends averaged lower production costs than the reference case. Changes in the parameter did not have a substantial impact on penetration results, which showed an average 0.9% change in 2050 market share across all scenarios.

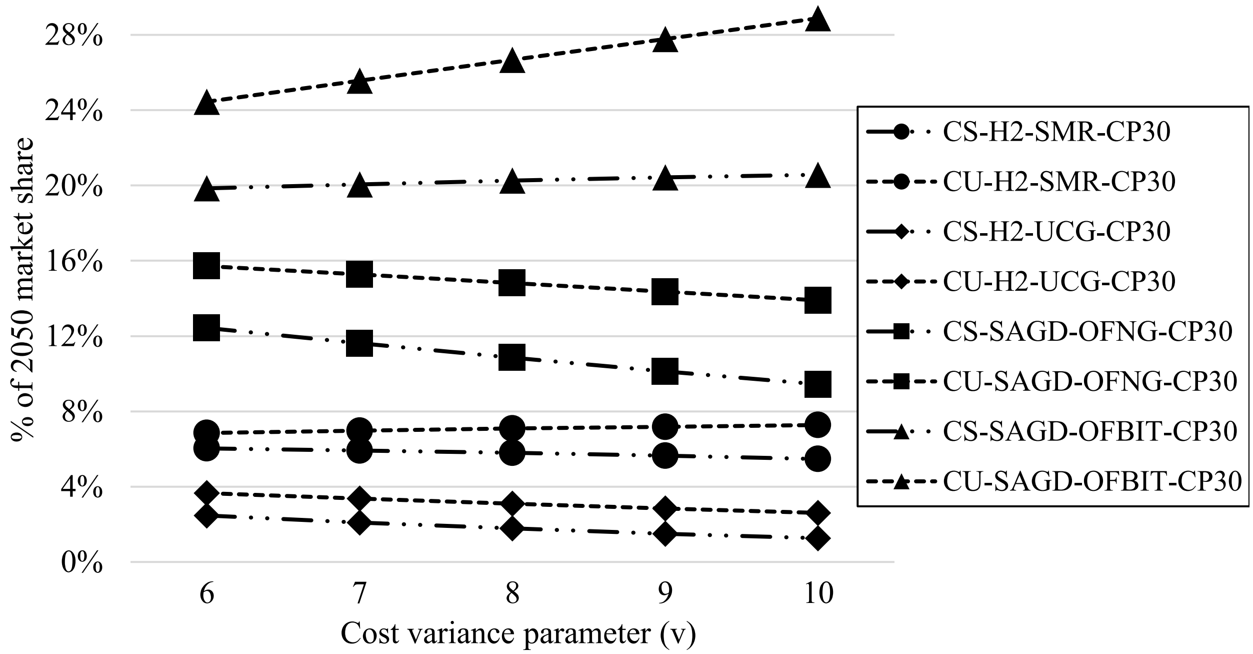


Figure 5-8: Sensitivity of the 2050 market share results to changes in the cost variance parameter

Changes to the forecasted natural gas price had a more substantial impact on 2050 market share results in certain scenarios; the results are shown in Figure 5-9. The SAGD-OFBIT-CCUS-CP30 market share changed by 8% across the range of natural gas prices examined, gaining 31% of the market when prices increased 20% and only 23% when prices decreased by 20%. The key reason for this result is that this technology is not fueled by natural gas, therefore its financial performance improves significantly with cost increases in the reference scenario in high gas price situations. Similar trends, though less pronounced, were observed in SAGD-OFBIT-CCS-CP30, H2-UCG-CCUS-CP30, and H2-UCG-CCS-CP30. The opposite trend was observed in SAGD-OFNG-CCUS-CP30, where market share reached 17% at a 20% price decrease and was as low as 13% at a 20% price increase. This technology is dependent on natural gas and consumes more than the reference case to supply additional energy for the carbon separation equipment, and therefore performs poorly in high gas price situations. The results for the remaining scenarios did not show significant changes. The observed trends are expected, as the technologies that do not depend on natural gas perform better when natural gas prices are higher.

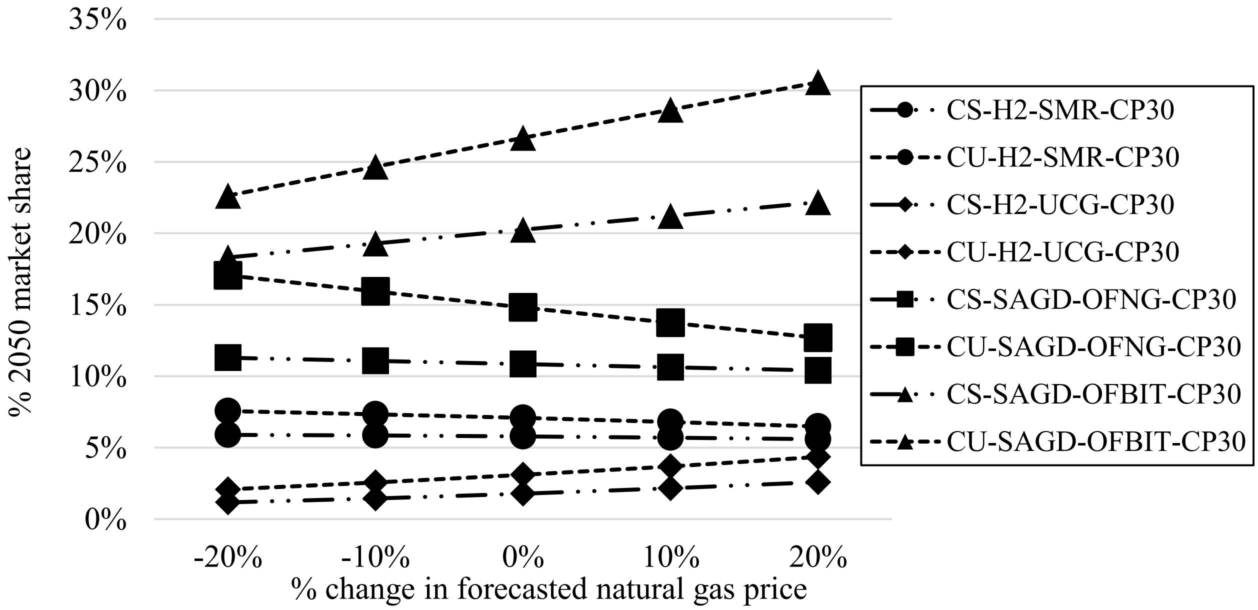


Figure 5-9: Sensitivity of 2050 market share results to changes in the natural gas price forecast

2050 market share results were also tested for their sensitivity to changes in the IRR used to perform economic analysis on the technologies, and the results are shown in Figure 5-10. SAGD-OFBIT-CCUS-CP30, SAGD-OFBIT-CCS-CP30, H2-UCG-CCUS-CP30, and H2-UCG-CCS-CP30 all showed consistent decreasing trends as IRR increased while the other scenarios were relatively unaffected by changes. Oxyfuel bitumen boilers and underground coal gasification technologies are more capital-intensive than the reference technologies they are compared to, which is the key reason for these trends.

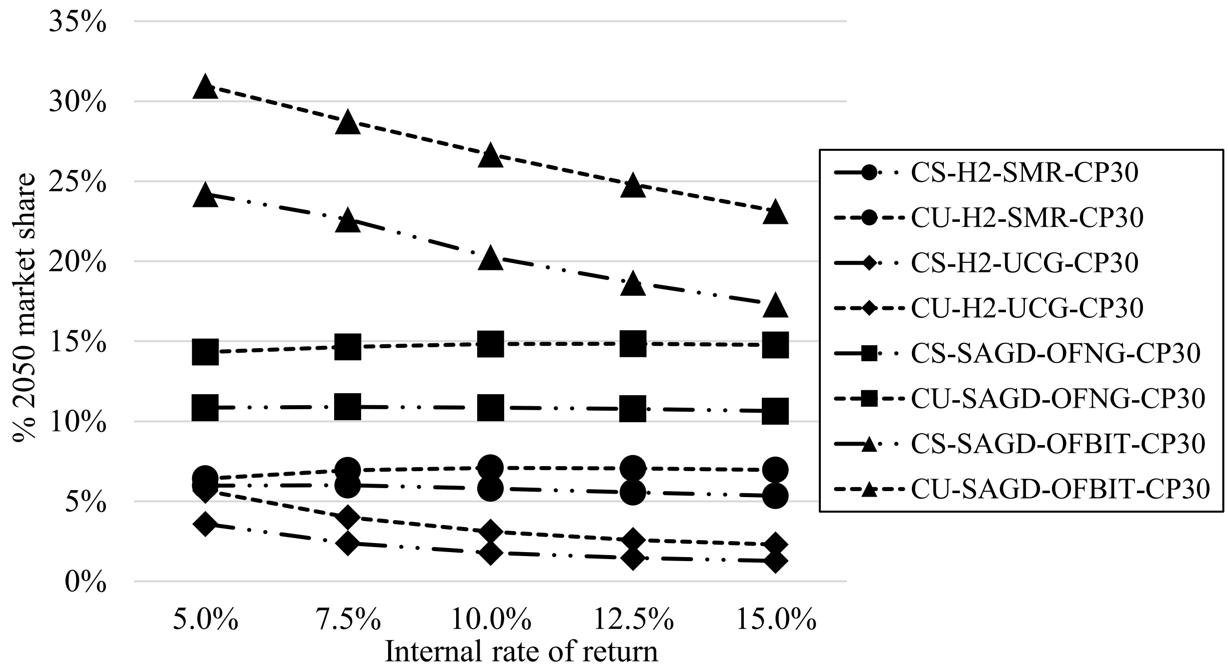


Figure 5-10: Sensitivity of marginal cost of GHG abatement to changes in the IRR

IRR selection also had a significant impact on the calculated cost of mitigation. The results from the sensitivity analysis are shown in Figure 5-11. The most significant difference observed was in H2-UCG-CCS-CP30, where the mitigation cost was \$6/tCO_2e when the IRR was decreased by 5% and \$53/tCO_2e when the IRR was increased by 5%. This technology had a high capital cost compared to the reference technology, with the result that IRR selection had significant impact on the technology. H2-UCG-CCUS-CP30, H2-SMR-CCUS-CP30, SAGD-OFBIT-CCS-CP30, SAGD-OFNG-CCUS-CP30, and H2-SMR-CCUS-CP30 all transitioned from negative marginal costs to positive marginal costs as the IRR increased, suggesting IRR selection can play a key part in financial viability of these technologies. These results show that the perceived risk of investing in these emerging technologies and the resulting IRR selected to conduct economic evaluation have a significant impact on the viability of the technologies examined in this work.

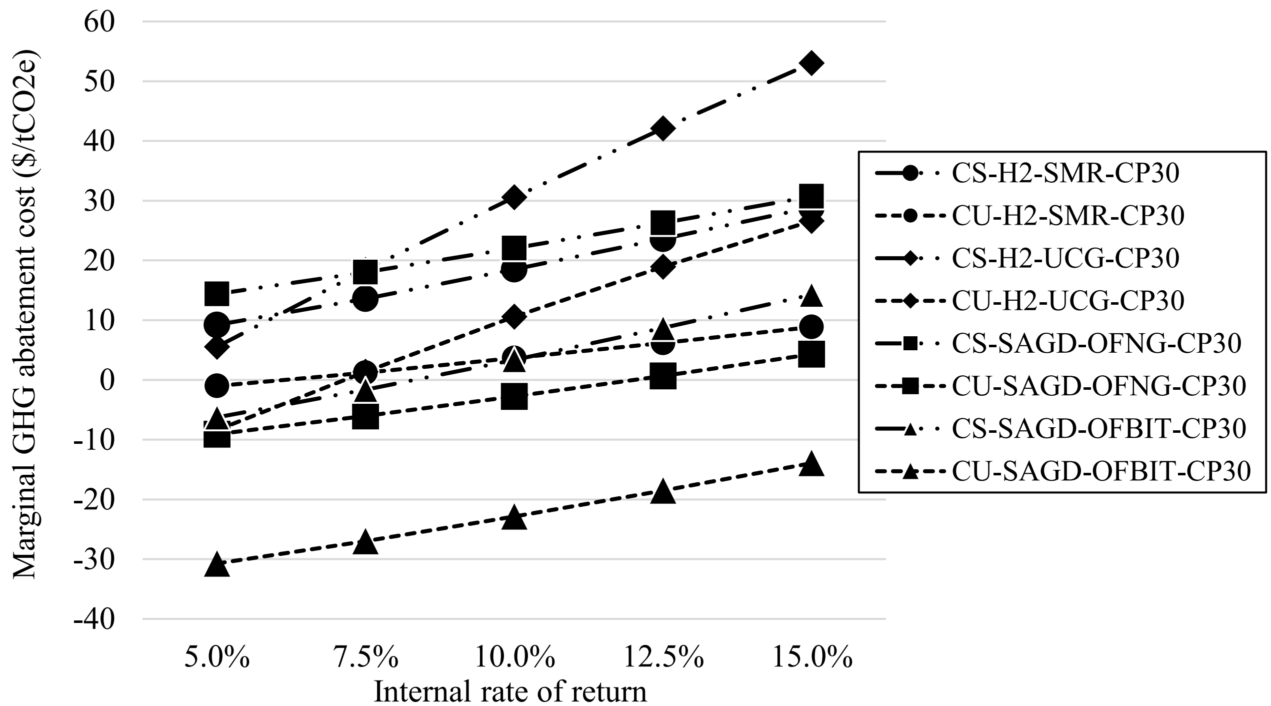


Figure 5-11: Sensitivity of marginal GHG abatement cost results to changes in IRR used for analysis

Market growth forecasts were tested for their impact on the total GHG mitigation potential of each scenario and are shown in Figure 5-12. In this evaluation, market growth was not found to have any impact on the relative cost of technologies, therefore market penetration results were not examined. Because of the larger expected growth of the in situ subsector than in the upgrading subsector, the SAGD technologies showed much more change in abatement potential. The most significant change was observed in SAGD-OFBIT-CCUS-CP30, where abatement potential was 138 Mt when growth forecasts were decreased by 20% and 207 Mt when growth forecasts were increased by 20%. The in situ subsector has the most significant growth forecast in the business-as-usual case, and SAGD-OFBIT-CCUS-CP30 was the best performing scenario, so further increases to expected market growth will have a larger impact on the abatement potential of the scenario.

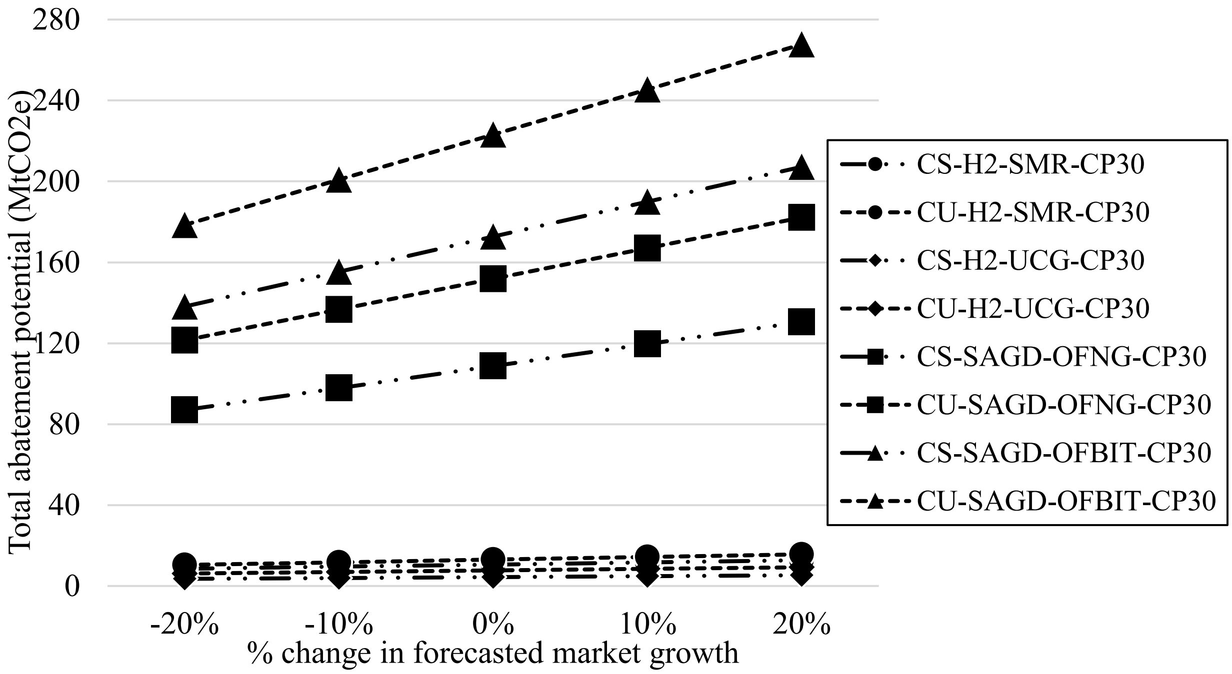


Figure 5-12: Sensitivity of total abatement potential to changes in the market growth forecast

The impact on marginal cost of GHG abatement results in each scenario to changes in the relative value of carbon credits is shown in Figure 5-13. The average change in the marginal cost across the scenarios was \$1.39/tCO_2e from credits being sold from 75% to 95% of the taxation rate, showing that this change does not have a significant impact on results. The results did not differ substantially from scenario to scenario; the largest difference was \$2.20/tCO_2e in SAGD-OFNG-CCS-CP30 and the smallest was \$0/tCO_2e in H2-SMR-CCS-CP30. The reason no change was observed in H2-SMR-CCS-CP30 is due to the low penetration of the technology in the first place, resulting in minimal emission abatement credits to add value to the scenario.

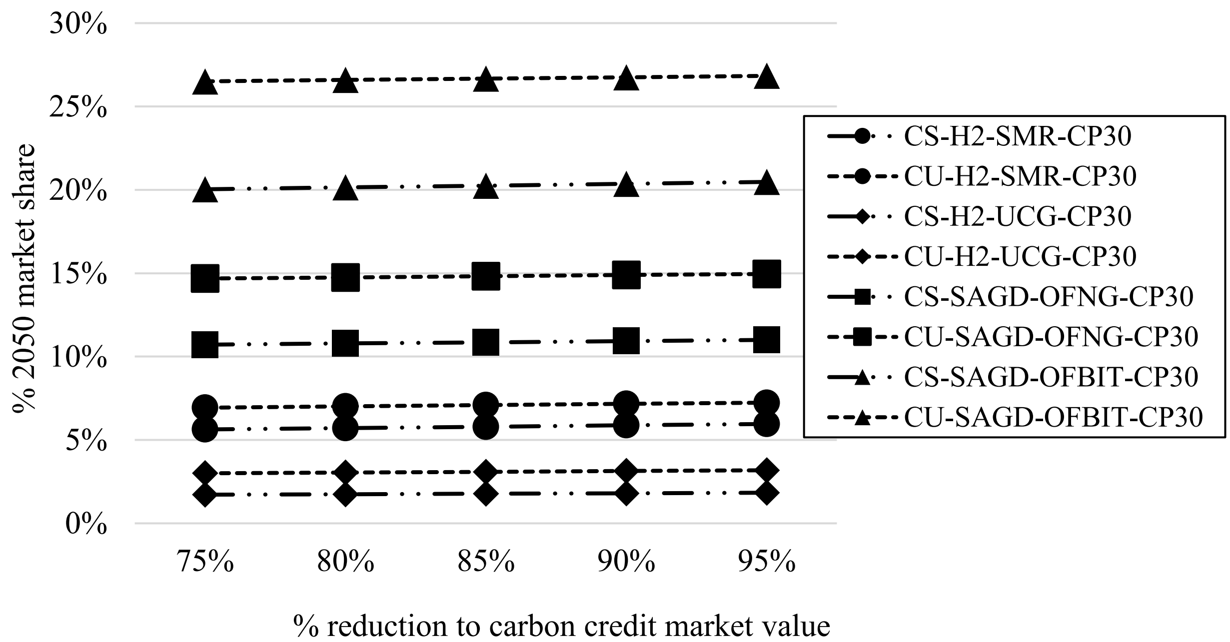


Figure 5-13: Sensitivity of the marginal cost of GHG abatement results to changes in carbon credit's relative value

The study results were most sensitive to the IRR parameter, which is expected due to CCUS technologies typically adding significant capital costs when compared to the business-as-usual technologies.

5.3.5 Limitations

The number of carbon capture and storage technologies considered in this study was limited due to the lack of research focused on the cost and performance of incorporating CCUS into oil sands processes. There are a growing number of technologies and processes available to conduct CCUS, and many show promise for reducing energy and costs [107]. Further research into these technologies applied to oil sands processes expand the present work to consider more options and other subsectors of the oil sands industry.

The methods used to evaluate technologies in this study also have limitations that are important to understand. The market penetration model uses diffusion principles for technologies gaining market share that assume a technology acceptance rate fits onto a symmetrical logit curve based on the cost of the incoming technology compared to what is currently used. While this approach is appropriate for estimating penetration with currently available information, a penetration rate is not necessarily symmetrical and is based on many factors besides costs. Unexpected technological improvements or limitations, social acceptance of one technology over another, and many other factors also impact the success of these technologies. Additionally, this study uses economic forecasts for industries and commodities that have fluctuated significantly throughout history. While the forecasts represent the best available knowledge currently, oil and gas markets are determined globally and are impacted by many factors that cannot be accounted for in the forecasts used. The reference case assumed the technologies currently being used in the oil sands will continue with their relative market shares until the end of the evaluation period. This was done so that a consistent base case could be developed that any technology could be compared to, but it does not accurately reflect changes such as technology and energy efficiency improvements and the need to develop reservoirs for continued growth. In addition, market shares gained by the evaluated technologies are based on forecasted growth in the industry and do not consider the potential to retrofit existing facilities with these technologies, which is feasible. The cost data used in the study is not valid for this type of use and no studies exist that considered the cost difference.

A final limitation is in the carbon pricing evaluation. Currently, carbon credits from technologies operating under the emission benchmarks are traded at some value below the taxation rate depending on their availability in the industry. No data is available on the average value of these credits, so this study assumed they were traded at 85% of the market value and conducted sensitivity analysis to understand the impact of that assumption on the results.

5.4 Conclusions

Carbon capture, utilization, and storage technology in the Canadian oil sands could play a key role in GHG abatement, helping Canada meet its emission reduction commitments and industry meet provincial legislation. A novel oil sands CCUS model was developed that integrates market penetration and long-term bottom-up energy accounting, providing a data-intensive and transparent method for the evaluation of different CCUS technologies. Twenty-four scenarios were evaluated for market adoption, GHG abatement potential, and marginal GHG abatement costs covering a range of technologies, policy scenarios, and market conditions to identify optimal pathways for CCUS technologies to gain market share.

The results show that of the two subsectors analyzed (upgrading and in situ), in situ offers significantly greater potential for CCUS technologies. Market penetration modeling results show in situ scenarios ranging from 9.3-27.7% of 2050 market share, whereas upgrading subsector scenario results range from 1.3-7.5% of the 2050 market share. Subsequent 2050 GHG abatement potential ranges from 92 Mt to 232 Mt for in situ scenarios and 3 Mt to 14 Mt in upgrading scenarios, with a maximum combined abatement potential of 246 Mt for scenarios that can be implemented simultaneously. The expected growth of the in situ subsector compared to the upgrading subsector and the cost competitiveness of CCUS technologies in the in situ subsector are the key reasons for these results.

The top performing technology in this study is oxyfuel boilers using bitumen for fuel. GHG abatement potential and marginal cost of abatement results range from 232 Mt at -\$28/tCO_2e to 150 Mt at \$12/tCO_2e, depending on the carbon pricing policy and end use of the captured carbon considered. Of the 6 scenarios that considered this technology, 4 had marginal abatement costs below zero. This means that long-term cost savings would be anticipated with this technology in those scenarios along with GHG emissions' reduction, making these scenarios of special interest to industry planners, policymakers, and stakeholders.

Three carbon pricing policies and two captured carbon end uses were considered for each technology in order to cover the range of possible market conditions into which these technologies could be implemented. The 2050 market share gained by technologies averaged a 3% increase in in situ subsector technologies and a 1.5% increase in upgrading subsector technologies moving from \$0/tCO_2e to \$50/tCO_2e carbon pricing. Under the \$50/tCO_2e carbon pricing, up to 246 Mt of GHG abatement (7.2% of oil sands emissions) was possible at -\$26/tCO_2e marginal cost. With no carbon pricing, this was reduced to a 220 Mt abatement potential at a -\$12/tCO_2e marginal cost. These results suggest that over the evaluation period up to 8 Mt/year of GHG emissions could be abated using CCUS technologies.

The option to sell captured carbon for utilization and storage in oil wells resulted in average 2050 market share increases of 5.2% and 1.3% for in situ and upgrading subsector scenarios, respectively. The 2050 GHG abatement potential is expected to increase by as much as much as 60 Mt with marginal costs decreasing by \$25/tCO_2e in the utilization scenarios. These results show that policy support through carbon pricing and advocating for a carbon utilization market through enhanced oil recovery operations would both have significant impact on the viability of CCUS technologies in the oil sands.

The results from this study are of value to government policymakers and industry stakeholders for identifying and promoting the best CCUS technology options for cost-effective emission reductions and even possible areas for profit. The results summarize the key subsectors where emissions can be reduced with CCUS technologies, show the impact of policies that provide incentives for reducing emissions, and help quantify what levels of emission reduction can feasibly be achieved at different costs. This information can be used to optimize investment in specific technologies, structure policies effectively, and set attainable targets. The modeling structure can also be expanded to other technology types, providing a consistent framework and reference scenario to compare any technology with GHG emissions abatement potential in the oil sands industry.

6 A preliminary look into the long-term GHG abatement potential of emerging oil sands in situ extraction technology

6.1 Introduction

The goal of in situ techniques is to physically alter the bitumen in the ground to make it possible to pump it to the surface. The viscosity of in situ bitumen is typically >100,000 centipoise (cP) and must be decreased to <10 cP to be pumped to the surface [45]. Traditional SAGD mobilizes bitumen by heating it with pressurized steam. Three key issues face SAGD processes: high supply cost, mainly driven by natural gas consumption; high water consumption due to steam requirements; and high GHG emissions due to high natural gas use. Natural gas prices are forecast to increase over the next 30 years, which will increase supply costs [14]. Furthermore, water used in SAGD processes is almost entirely treated and recycled, resulting in high treatment costs [44]. Finally, sector-wide GHG emissions were recently capped at 100 million tonnes (Mt) [9] and a carbon pricing system was implemented [8]. Several processes in various stages of development have emerged that have the potential to reduce GHG emissions and water use, thus alleviating many key concerns with in situ production. Emerging processes use hydrocarbon solvents in lieu of steam, hybrid steam-solvent processes, combined electromagnetic heating and solvent processes, chemical additives with steam, and in situ hydrocarbons combusted to heat the reservoir.

Pure solvent processes replace steam entirely with a hydrocarbon solvent, eliminating the need for water in the process and substantially reducing the amount of heat required. Rather than heating the bitumen to reduce the viscosity, solvents are dissolved into in situ bitumen, resulting in a diluted, lower viscosity product [125]. Research is ongoing to identify optimal solvent types and solvent injection temperature, but work to date suggests lighter hydrocarbons perform better and heated solvents result in better drainage rates [43]. The recovery of injected solvents from the reservoir is a key issue with these technologies and has a significant impact on their cost effectiveness and environmental performance. Energy requirements for producing bitumen with pure solvent processes vary depending on the extent to which the solvent is heated. Cold solvent processes do not heat the injected solvent, thus GHG emissions are 80% lower than for SAGD, but suffer from slow bitumen mobilization in testing [45]. Soiket et al. conducted a life cycle assessment (LCA) on the heated pure solvent process and found that compared to SAGD, GHG emissions fell by 64-79% [126]. Zhang et al. analyzed two different heated solvent injection processes experimentally and found that production rates significantly improved compared to traditional SAGD and were in line with expected performance from simulations [127]. Nenniger and Dunn conducted a correlation study on the results from experimental, numerical, and analytical studies on solvent-based extraction and concluded that the data shows strong production improvements associated with solvent-based extraction and potential opportunities to reduce production costs from traditional SAGD [125].

Solvent-assisted SAGD (SA-SAGD) uses a combination of steam and solvents to mobilize in situ bitumen and has received significant research and commercial interest. Perlau et al. reported the performance of a pilot project using SA-SAGD near Cold Lake, AB using 20% solvent with dry steam by volume [128]. The study confirmed that incorporating solvents in production improved the plant's performance and that the use of lighter hydrocarbons as solvents aided in solvent recovery. Souraki et al. conducted simulation studies comparing SA-SAGD and traditional SAGD and found that SA-SAGD generally outperformed SAGD and was less sensitive to lower reservoir porosities [129]. Hexane was the solvent of choice for the study; however, simulations were also run using pentane and heptane and did not result in a meaningful performance difference. Nasr and Ayodele studied the results of simulations, experiments, and field tests for SA-SAGD applications and found that SA-SAGD generally resulted in better oil recovery compared to traditional SAGD and anticipated the process would improve in situ production economics and reduce GHG emissions [130].

Another option for heating solvent in solvent-based in situ production is electromagnetically using radio frequency to raise the reservoir temperature (EM-SAGD). Koolman et al. conducted reservoir simulations using inductive heating and found that production rates could be tripled using electromagnetic heating with minimal steam and boiler capacity additions [131]. Wise and Patterson studied the expected supply costs using a form of EM-SAGD called Effective Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH^{TM}) with a 10,000 bpd facility and forecast that it could reduce energy requirements by 50% compared to traditional SAGD and remain economically viable with West Texas Intermediate crude oil prices below $60 [132]. Safaei et al. conducted an LCA on the ESEIEH^{TM} process and found GHG emissions to be less than those from SAGD by 3-50% using emission factors from Alberta's current electricity mix [133]. The authors also found that the majority of the energy required for this process is from electricity demand; if the electricity was supplied from renewable sources, GHG emissions from the process would drop by 83% [133]. Finally, Bera and Babadagli reviewed the existing computational, experimental, and field-based studies on EM-SAGD and found that most studies suggest that the process is economically feasible compared to traditional SAGD but noted that more field testing is necessary [134].

Existing studies have focused on understanding the technical performance of these technologies and included field test performances, comparisons of simulations and lab results, and life cycle analyses to determine GHG emission factors. These studies lack both detailed economic analysis and long-term analysis of the GHG abatement potential associated with their adoption. Ardali et al. reviewed existing solvent-based extraction techniques and suggested that the steam/solvent hybrid methods have the greatest opportunity for success based on literature results [43], but did not offer quantified results of expected market penetration or cost savings. To the author's knowledge, only Nduagu et al. evaluate the cost, performance, and GHG reduction potential of these technologies; however, their study does not project market penetration or provide GHG abatement potentials. There is a need to understand the long-term market penetration and GHG abatement potential of these technologies based on their expected performance and costs.

This research addresses these gaps through the novel application of market penetration modelling and bottom-up energy accounting of the technologies. The analysis allows for market penetration and the resulting GHG emissions abatement and marginal costs of the technologies to be forecast in long-term scenarios (30+ years). To the best of the author's knowledge, this is the first time the long-term GHG mitigation potential has been assessed for these new technologies. The study also analyses the latest emission policies, such as carbon pricing and industry emissions caps, for their impact on technology penetration. By developing this framework and analyzing these technologies, we can compare them to other technology options using a consistent framework, and performance information can easily be updated as the understanding of the technologies improves.

The methods discussed above are applied to address the identified research gaps with the aim of achieving the following objectives:

- Update the LEAP-Oil sands model with the emerging in situ extraction technologies identified above;
- Develop a market penetration model to analyze the expected market shares of solvent-based, steam/solvent hybrid, and electromagnetically heated solvent-based extraction techniques based on their cost compared to the currently dominant SAGD process; and
- Determine the GHG abatement potential and marginal cost of incorporating these processes compared to continuing to use the SAGD process over a period from 2020-2050.

6.2 Method

6.2.1 Framework

The general framework for analysis detailed in Sections 2 and 3 was followed. The technologies considered in this section are all from the in situ SAGD subsector and offer modifications that have the potential to reduce energy consumption, increase productivity, or a combination of both. Each technology was evaluated using the market penetration model and LEAP-Oil sands model with the other advanced technologies and the traditional SAGD process used for the reference scenario.

6.2.2 Scenario development

Scenarios were developed using the reference case SAGD subsector and techno-economic data for the performance of advanced extraction processes. The reference case for the SAGD subsector is discussed in greater detail in Section 3, and Table 6-1 shows the key performance measures used to develop the reference scenario or business-as-usual (BAU), taken from Katta et al. [12], and the technology scenarios, taken from Nduagu et al. [45]. These technologies are still in development, therefore a broad sensitivity analysis was conducted and is outlined in Section 6.2.5.

Table 6-1: Key energy information for processes investigated taken from Nduagu et al. [45]

Process	Key energy performance metrics
Traditional SAGD	Natural gas – 1.01 GJ/bbl Produced gas – 0.17 GJ/bbl Electricity – 16.7 kWh/bbl
Pure solvent injection	75% reduction in natural gas requirement
Hybrid steam/solvent	35% reduction in natural gas requirement 10% production rate uplift
Solvent with electromagnetic heating	75% reduction in natural gas requirement 160% increase in electricity requirement

Cost data for each scenario is compared to the reference case SAGD facility's costs. Reference case costs are based on the construction of a new 40 kbpd facility that is in line with currently operational facility sizes and expected growth in the subsector. Scenario costs are developed by modifying the detailed costs of the reference case according to expected changes in capital and operational expenses. Each scenario is also evaluated under three different carbon pricing scenarios. "CP0" applies no cost for carbon emissions. "CP30" applies a \$30/tCO_2e cost for emissions exceeding the emission benchmarks outlined in the Alberta Government's Standard for Establishing and Assigning Benchmarks. "CP50" applies a \$50/tCO_2e carbon price for emissions exceeding the same emission benchmarks, with pricing aligned with the PCF [4]. Costs in each scenario are annualized and given in 2019 \$CAD in order to calculate an annual cost per unit of production in each case, as outlined in Equation 2-1. Annualized costs and the resulting emission factors for each process are outlined in Table 6-2 along with the sources.

Table 6-2: Advanced extraction scenario descriptions

Subsector	Scenario name	Description	Annualized cost ($/bbl)*				Emission factor (kg CO_2/unit produced)
			CC	OC	ECC	EC*	
Steam assisted gravity drainage (Steam production)	Reference	Boiler steam	13.02	8.64	0.056	$1.12 \cdot P_{NG} + 16 \cdot P_{ELEC}$	56.0
	ADV-SOLV	Pure solvent injection	9.12	16.32	0.015	$0.28 \cdot P_{NG} + 16 \cdot P_{ELEC}$	15.1
	ADV-SOLVST	Hybrid steam/solvent injection	12.39	7.86	0.048	$0.66 \cdot P_{NG} + 16 \cdot P_{ELEC}$	47.6
	ADV-SOLVEM	Solvent injection with electromagnetic heating	12.33	5.00	0.033	$1.12 \cdot P_{NG} + 60 \cdot P_{ELEC}$	33.2

*Energy cost equations were developed from the energy requirements outlined in [119] for the reference case SAGD facility. P_{NG} = price of natural gas ($/GJ); P_{ELEC} = price of electricity ($/kWh)

There is limited data available for the expected cost savings and performance gains for the processes examined in this section. Currently, the only data available on cost and performance of multiple options in advanced extraction is found in a report by Nduagu et al. [45]. Further research is needed into the techno-economics of these options to be confident in the expected performance, and for that reason a wide range is examined in the sensitivity analysis outlined in Section 6.2.5. As data becomes available, the model can be easily updated to reflect updated results.

6.2.3 Market penetration modelling

With Equations 2-1 and 2-3 as explained in Section 2 the market penetration of each scenario from 2020 to 2050 using a market penetration model developed in excel was calculated. The performance and cost of the scenarios examined are based on equivalent-sized facilities to that used in the reference case (40 kbpd), which is in the average range of currently operating facilities [121]. This ensures that the scenarios can be feasibly implemented. The maximum penetration a scenario can achieve is based on the forecasted growth of the subsector where the technology from the scenario is being used during the growth period. Using the market penetration modelling framework, the cost of the technologies being considered and the reference technology were compared and assigned market shares to each based on market diffusion principles are outlined in Section 2. In the market penetration model, the technology options compete with each other and are assigned a share of the annual production growth based on their expected cost performance that year. The market penetration is calculated with the market share gained each year combined with the forecasted growth in that year. Table 6-2 shows the annualized costs per unit of production input to the market share model outlined in Equation 2-1.

6.2.4 LEAP scenarios and abatement cost curves

The scenarios in this section are only applicable to the SAGD subsector, therefore each scenario is contrasted to the steam generation technology outlined in the LEAP-Oil sands demand module. Section 3 outlines the details of the in situ SAGD subsector in the LEAP-Oil sands model, where the alternative technology scenarios presented here were used to replace the reference SAGD technology. The LEAP-Oil sands model determines GHG emission levels by accounting for the energy consumed by each technology and the associated emissions that result. Technology scenarios are compared to the reference scenario to determine the GHG abatement potential over the evaluation period. Equation 4-3 was used to calculate the GHG abatement costs in each scenario and associated curves were developed with costs determined from the market penetration model.

6.2.5 Sensitivity analysis

The sensitivity of the results to key variables was determined to test the factors that could influence the viability of these technologies the most. In the case of the considered technologies, the market penetration results were checked with respect to the cost variance factor used (from 6 to 10). The sensitivity of market penetration and the marginal cost of GHG abatement to changes in forecasted natural gas prices and market growth were tested for a range of +/- 20%. The IRR values used in cost calculations were changed from 5% to 15% to test the sensitivity of the results to the perceived risk of the technologies. Finally, given the limited data availability for these technologies, the expected capital and operating costs were changed by +/- 30% for each scenario.

6.3 Results

6.3.1 Market penetration results

Figure 6-1 shows the market shares gained in each scenario in 2050 in relation to the maximum achievable penetration. Based on forecasted growth in the SAGD subsector, a maximum market share of 58% is possible by 2050. ADV-SOLVST achieves the highest 2050 market share at 25%. The ADV-SOLV and ADV-SOLVEM scenario penetration rates increase as carbon pricing increases, with the top performing scenario, ADV-SOLVEM-CP50, reaching an 18% market share in 2050. ADV-SOLVST decreases in market share as carbon price increases. This result is not surprising, given that the steam-solvent hybrid technology has a higher emission factor than the other two technologies considered. Despite the reduction in penetration as carbon price increases, the 2050 market penetration of the steam-solvent hybrid scenarios is higher than the other two technologies in every carbon pricing scenario due to its lower forecasted cost.

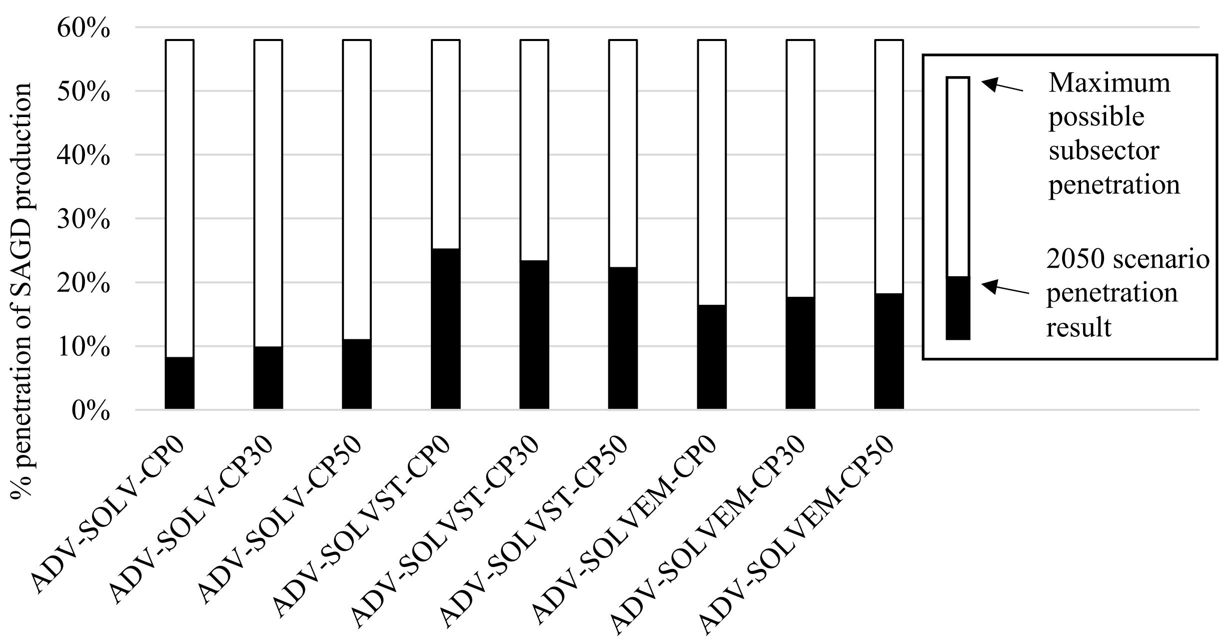


Figure 6-1: Market penetration results for 2050

6.3.2 GHG emissions from LEAP-Oil sands

The total forecasted GHG emissions were calculated for each scenario in the LEAP-Oil sands model, and in Figure 6-2 the results from CP30 are compared to the business-as-usual scenario. GHG emissions fell in the technology scenarios because less natural gas was required with the use of solvents for bitumen extraction in conjunction with or instead of steam. GHG emissions are noticeably reduced (by at least 4.5 MT annually) in each scenario compared with the BAU scenario. Figure 6-2 also shows the same results considering only cap-relevant emissions and showing the 100 MT emissions cap for reference. In every scenario there were significant delays in exceeding the emissions cap, with ADV-SOLV-CP30 and ADV-SOLVEM-CP30 going over in 2049 (an 8-year delay) and ADV-SOLVST-CP30 exceeding in 2048 (a 7-year delay).

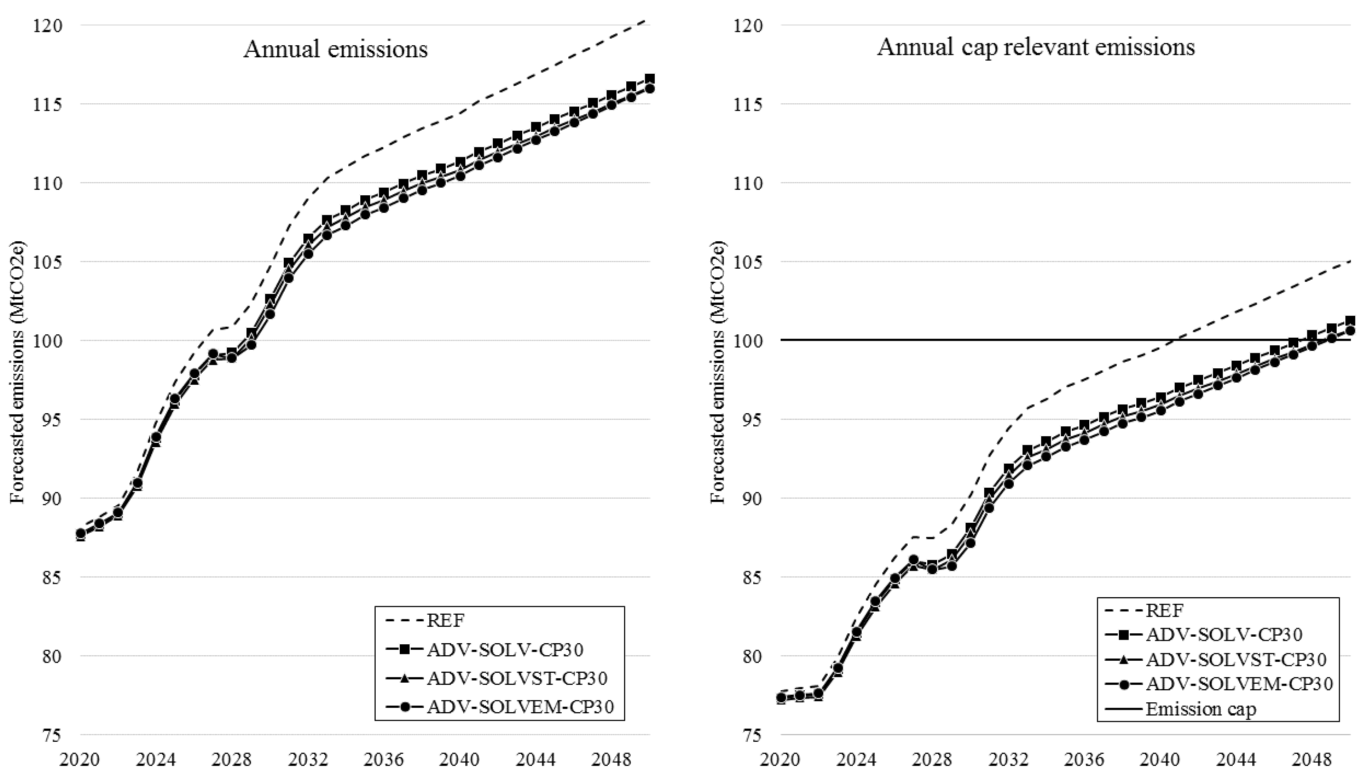
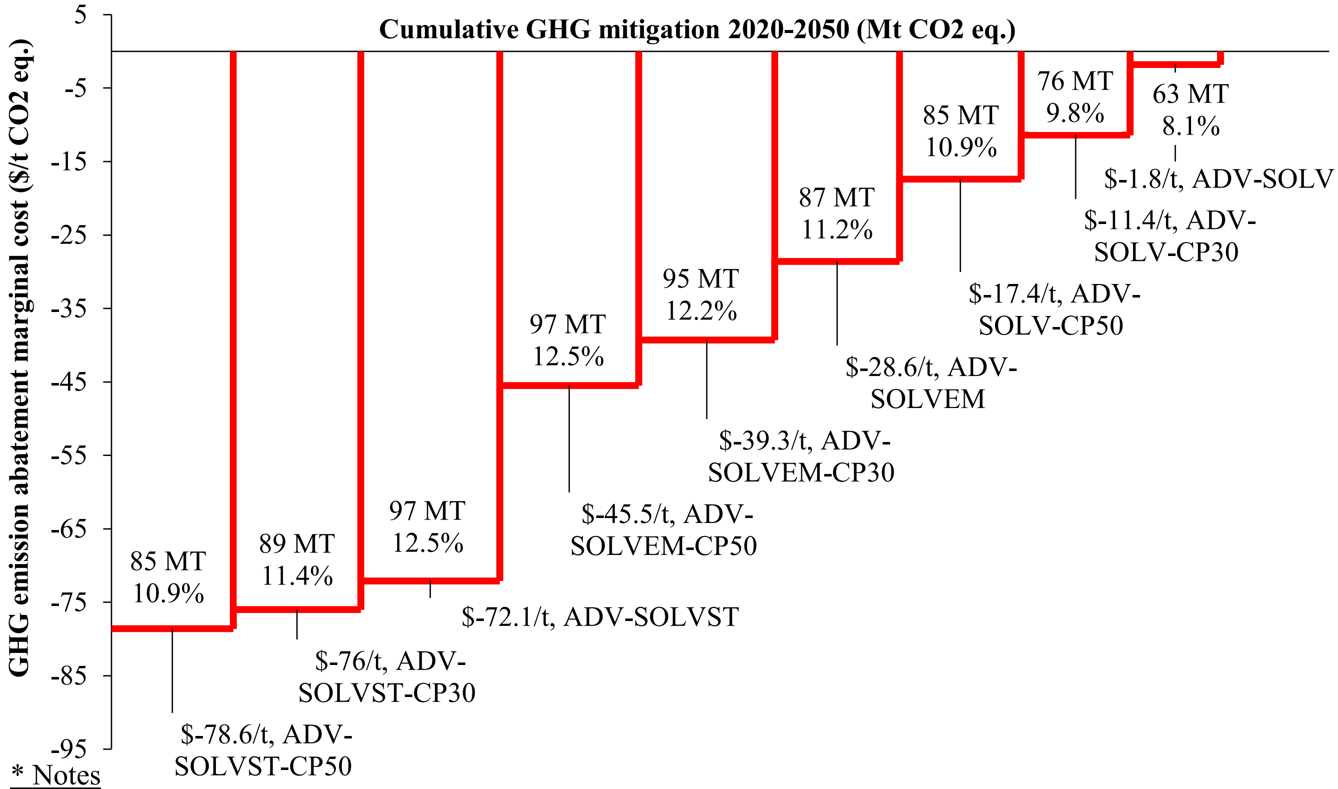


Figure 6-2: Annual emission results from CP30 scenarios with no exclusions (left) and cap-relevant exclusions (right)

6.3.3 GHG mitigation cost curves

Figure 6-3 shows the cost curves for the considered advanced extraction scenarios during the 2020-2050 evaluation period organized from lowest marginal cost to highest. Every scenario in this analysis resulted in cost savings over the evaluation period. ADV-SOLVST-CP50 had the most significant cost savings at -\$79/tCO_2e due to the relatively low capital and operating expenses combined with the performance gains expected. The steam-solvent hybrid scenarios (ADV-SOLV, ADV-SOLV-CP30, and ADV-SOLV-CP50) showed the lowest savings of -\$2/tCO_2e, -\$11/tCO_2e, and -\$17/tCO_2e, respectively, mainly because of the high solvent cost associated with the process. Abatement potential by scenario ranged from 63 MT to 97 MT. The highest abatement potential was in scenario ADV-SOLVEM-CP50 at 97 MT at a cost of -\$45/tCO_2e, representing 2.8% of total oil sands emissions. This technology resulted in high GHG abatement potential because the combination of its improved cost performance (compared to the pure solvent process) increased its market penetration and its lower GHG emissions factor (compared to the steam-solvent hybrid process). Operating costs for electromagnetically heated solvent technologies were largely driven by the purchase of electricity to meet heating demands.



* Notes
NPV of costs discounted to 2020

Figure 6-3: 2018-2050 GHG mitigation cost curve

6.3.4 Sensitivity analysis

Sensitivity analysis was carried out on the key parameters, i.e., the cost variance parameter from Equation 2-3, the IRR used for financial analysis of technologies, natural gas price forecasts, and market growth forecasts. The impact on market penetration, GHG abatement potential, and marginal cost of GHG abatement was determined. The results presented here are from CP30 scenarios; however, regardless of carbon pricing, similar trends were observed in all cases. Figure 6-4 shows the market penetration results' response to changes in the cost variance parameter. The difference in final market share from a cost variance parameter of 6 to 10 averaged 2.5% across scenarios. The market shares of ADV-SOLV-CP30 fell as the cost variance parameter was increased, suggesting the pure solvent process generally cost less than the reference technology.

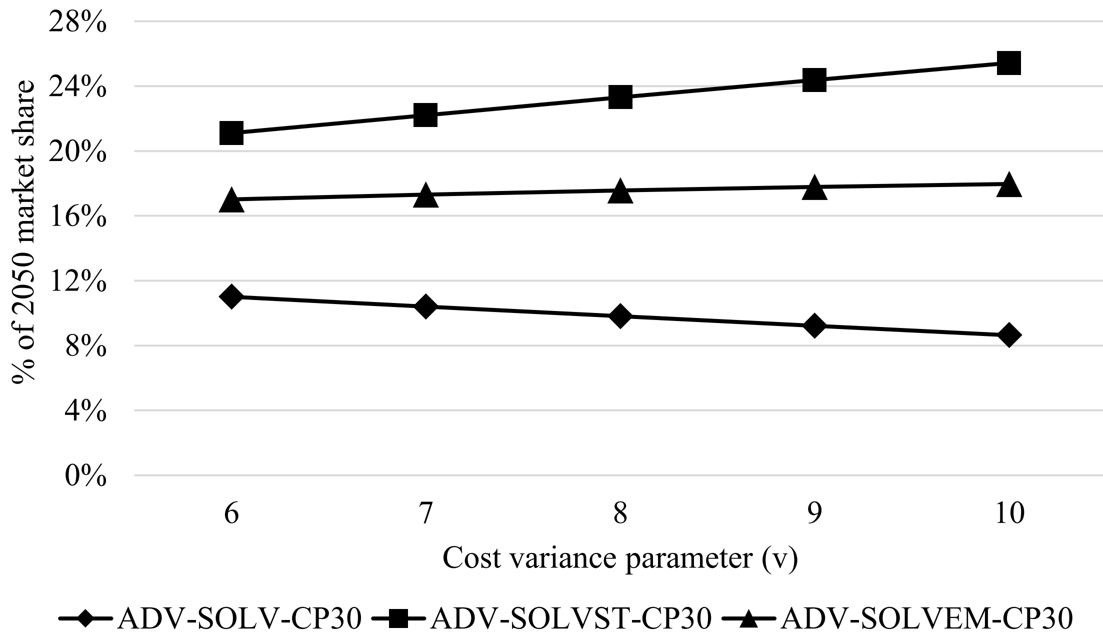


Figure 6-4: Sensitivity of the 2050 market share results to changes in the cost variance parameter

The results from the sensitivity analysis on the IRR are shown in Figure 6-5. All the scenarios showed a decreasing trend as the IRR increased because the capital expenses of these production options are lower than traditional SAGD. Both ADV-SOLVST-CP30 and ADV-SOLVEM-CP30 are relatively insensitive to changes in the IRR, with marginal GHG abatement costs decreasing less than \$10/tCO_2e, while ADV-SOLV-CP30 changes by over \$25/tCO_2e.

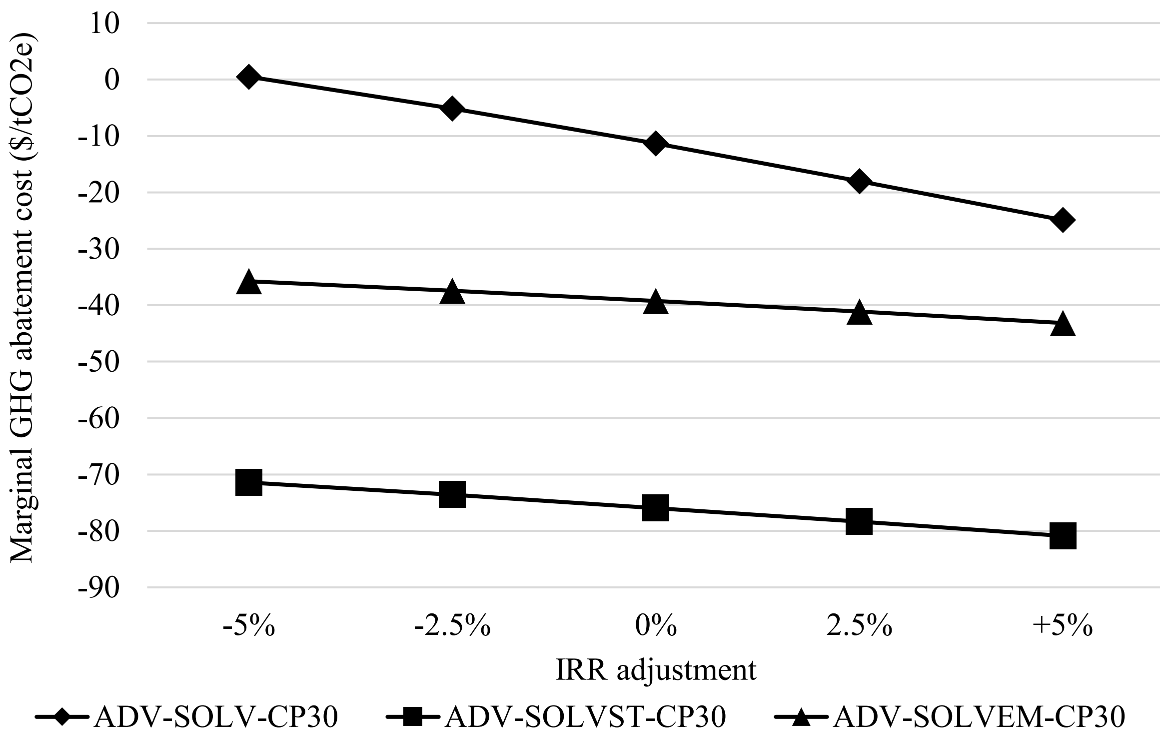


Figure 6-5: Sensitivity of marginal GHG abatement cost results to changes in the IRR

The impacts on the marginal cost of GHG mitigation from changes to the forecasted natural gas price are shown in Figure 6-6. ADV-SOLV-CP30 and ADV-SOLVST-CP30 were similarly sensitive to natural gas, changing by $15/tCO_2e and $17/tCO_2e, respectively, which is somewhat unexpected as the solvent/steam hybrid technology consumes more than double the quantity of natural gas as the pure solvent technology. The reason for this result is that the penetration model assigns less production to the steam/solvent hybrid option as prices go up, thereby reducing the change in marginal cost. ADV-SOLVEM-CP30 showed the largest change in results with a difference of $26/tCO_2e. All the technology options show a decreasing trend in marginal costs as natural gas price increases because they consume less fuel than traditional SAGD.

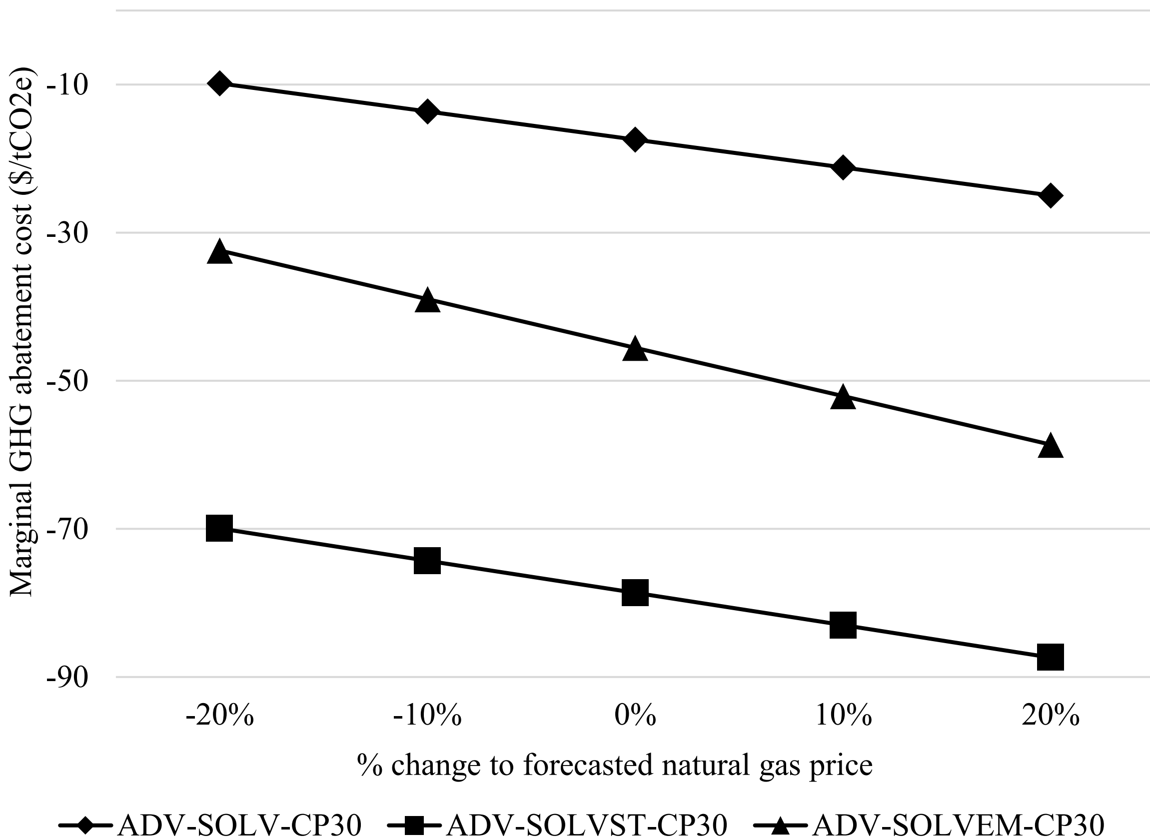


Figure 6-6: Sensitivity of marginal GHG abatement cost results to changes in forecasted natural gas price

Abatement potential results were tested for sensitivity to changes in the forecasted market growth, and the results are shown in Figure 6-7. ADV-SOLVEM-CP30 showed the greatest abatement potential difference, mitigating up to 113 MT when market growth is 20% greater than forecasted (19 MT greater than in the forecasted growth scenario).

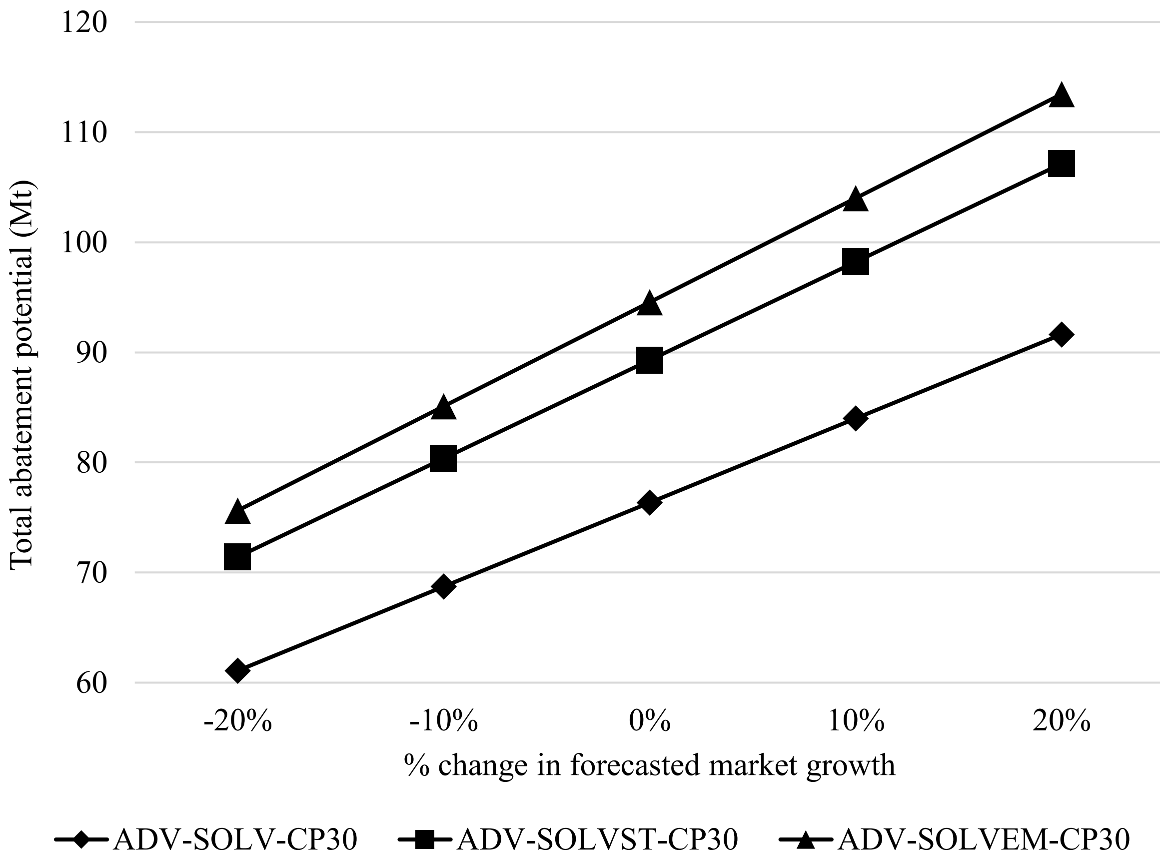


Figure 6-7: Sensitivity of abatement potential results to changes in forecasted market growth

Figure 6-8 and Figure 6-9 show the sensitivity of the total GHG abatement potential of each scenario to changes in capital cost and operating costs, respectively. When expected capital costs are lower than anticipated, the solvent-steam hybrid scenarios show the highest improvement in abatement potential, from 89 Mt to 107 Mt. The pure solvent scenarios show the opposite trend, losing market share and offering less GHG abatement potential compared to the other options as expected capital costs decrease. These results are due to the high expected capital costs of solvent-steam hybrid technologies giving them significant market advantages when capital costs decrease. If projected capital costs are increased by 30%, the pure solvent process performs better and is the top option with an 82 Mt abatement potential. This advantage levels off as CapEx continues to increase and the reference case becomes more competitive. When evaluating sensitivity to changes in operating expenses, solvent-steam hybrid scenarios again show the most GHG abatement potential in lower operating expense situations, from an expected 89 Mt to 107 Mt abatement potential when operating costs decrease by 30%. Electromagnetic heating scenarios perform better when projected operating expenses increase because of their relatively low operating costs, going from 95 Mt to 100 Mt when operating expenses are 30% higher than expected. Again, a leveling-off trend is observed here as operating expenses increase to the point that the reference case becomes more competitive. Overall, significant abatement potential for all scenarios is still expected across a wide range of forecasted capital and operating expenses, suggesting that the technologies examined can still contribute to GHG abatement in oil sands processes even if currently forecasted costs vary significantly.

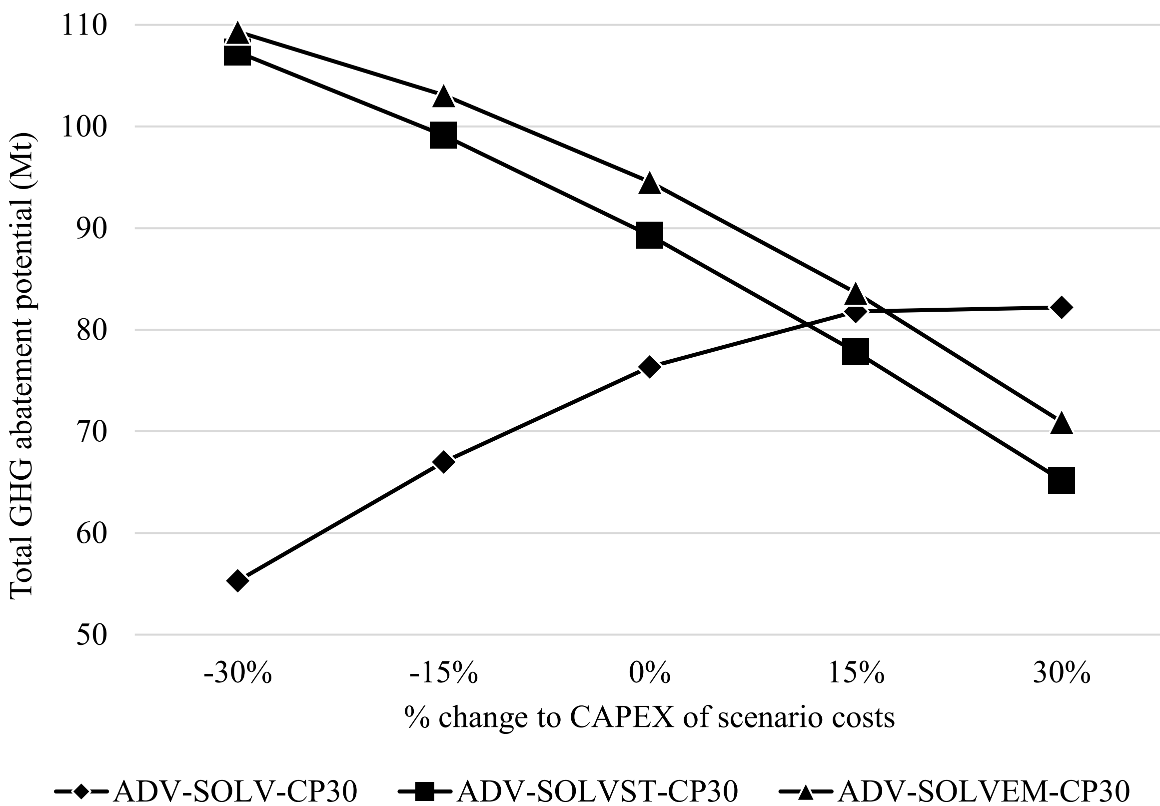


Figure 6-8: Sensitivity of total abatement potential results to changes in the CapEx of technology scenarios

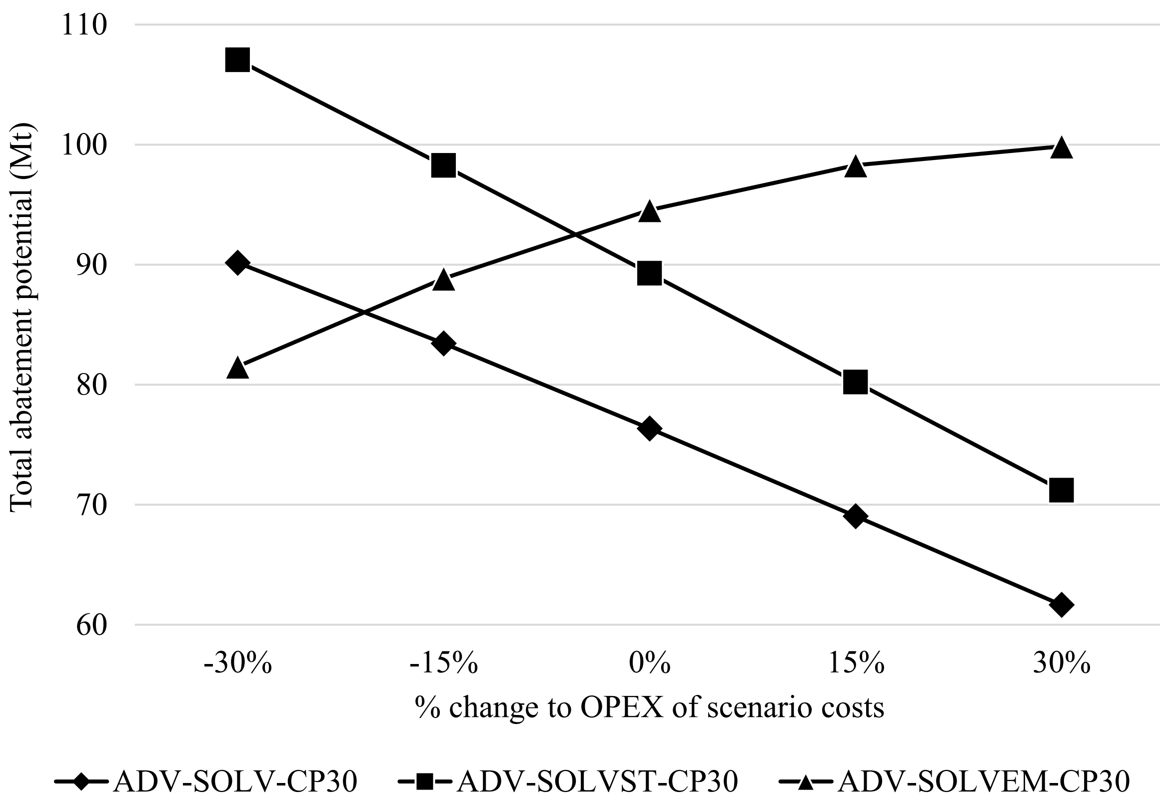


Figure 6-9: Sensitivity of total abatement potential results to changes in OpEx of technology scenarios

The overall results of the sensitivity analysis show that these technologies are still highly sensitive to changes in CapEx and OpEx values, so further technoeconomic research providing a high level of confidence in the selected values is important. Results were also particularly sensitive to changes in the IRR selected for analysis, suggesting that the perceived risk associated with the technology has a significant impact on its market viability.

6.4 Conclusion

This study considered three emerging advanced extraction techniques that have been proposed to replace traditional SAGD in the Alberta oil sands to determine their GHG abatement potential and marginal costs. Despite their promise for reducing industry GHG emissions and significant research into their technical capabilities, there is no research on the long-term market penetration and GHG abatement potential of these technologies. Using market penetration and bottom-up energy modelling, we developed a framework for evaluating the expected performance of each technology and forecast the market penetration potential, GHG abatement potential, and marginal costs of each technology in the 2019-2050 evaluation period. Technologies were evaluated under three different carbon pricing policies to better understand the impact of policies on their viability.

All the scenarios showed cost savings when compared to traditional SAGD extraction techniques, making them attractive options for further research. Hybrid steam/solvent systems (ADV-SOLVST scenarios) had the best market penetration and marginal cost performance. When evaluated with CP30 carbon pricing, this technology was projected to gain 23% of the SAGD market share versus 18% for electromagnetically heated solvent systems and 10% for pure solvent systems. These market share gains resulted in a -\$76/tCO_2e marginal cost of abatement in steam-solvent hybrid systems, which was nearly twice as low as the results achieved by electromagnetic systems. Despite the weaker cost performance, electromagnetically heated solvent systems (ADV-SOLVEM scenarios) projected the highest GHG abatement potential (95 Mt with CP30 carbon pricing) because of their low emission factors; this is 6 Mt greater than steam-solvent hybrid systems. Sensitivity analysis was conducted on the key parameters used in the research, including natural gas prices, market growth, and technology costs. Of note is that substantial abatement potential was still forecast even with significantly increased capital or operating expenses in one of the examined technologies, suggesting resilience to cost increases and highlighting that they are worthwhile to research further.

All three of these technology options are still in development and their effectiveness is still being optimized. As such, further research into performance and cost would allow for more reliable results from our model. Other novel extraction techniques such as the use of surfactants and thermal extraction through in situ combustion have also been proposed, and further research into their cost and performance would allow them to be incorporated into this model. The technologies and scenarios evaluated in this study are of use to policymakers and industry stakeholders for gaining a better understanding of the GHG emission reduction potential of emerging production techniques and associated costs. The methods applied in this work can be applied to other technologies as more information about their performance and cost becomes available and the model developed can be updated to incorporate new developments for the technologies evaluated here.

7 An assessment of opportunities for cogenerating electricity to reduce greenhouse gas emissions in the Alberta oil sands[3]

7.1 Introduction

Crude oil made up 32% of global energy production in 2017 and reports suggest that global energy demands increases will outpace the development of renewable energy options for at least the next 20 years [100]. In 2017, Canada produced 5.6% of global crude oil [99], 65% of which was sourced from the oil sands [13]. Canada has the third largest proven oil reserves in the world with the vast majority found in the oil sands and only around 5% have been produced to date [67]. Crude oil production from the Canadian oil sands has more than doubled since 2010 and is expected to grow by another 35% by 2040 [13].

Crude oil mined from the Canadian oil sands is initially produced as bitumen and then is further processed before being sent to refineries. Bitumen processing is energy-intensive and contributed approximately 10% of the national greenhouse gas (GHG) emissions in the same year and accounted for 41% of the nation-wide oil and gas sector GHG emissions [6]. The Canadian government has signed the Paris Agreement, an international commitment to reduce GHG emissions, and has identified the industrial sector, including bitumen production, as an important area to reduce GHG emissions [4]. The industry is expected to grow in the next 20 years [13]; therefore, methods of reducing GHG emissions from the industry are needed if national GHG emission reduction targets are to be met. Renewable energy, carbon capture, energy efficiency, novel extraction technologies, and increased cogeneration may be viable strategies to reduce GHG

[3] A version of this chapter has been submitted for publication, titled: R. Janzen, M. Davis, A. Kumar, "An assessment of opportunities for cogenerating electricity to reduce greenhouse gas emissions in oil sands," Energy Conversion and Management (Submitted), 2020.

emissions from oil sands processes. Cogeneration, unlike many of the other options, is already used in some oil sands operations; it can be an efficient and cost-effective means of increasing process efficiency [135]. Oil sands' industry-wide GHG emission levels could decrease if cogeneration were deployed widely in future growth.

Crude bitumen production can be broken into two main categories, surface mining and in situ. Surface mining involves traditional open pit mining processes followed by the separation of bitumen from sands through various processing techniques. In situ production is used for deep reservoirs and typically involves pumping steam into the reservoir to heat and mobilize the bitumen so it can be pumped to the surface. Once separated, crude bitumen is either diluted to pipeline specifications with light hydrocarbon diluents or upgraded to synthetic crude oil (SCO). Current energy demand for bitumen extraction from mined ores, in situ production, and upgrading is met through natural gas fuels and electricity consumption, either from the grid or produced on-site [16]. Electricity is used to power various equipment including mobile mining equipment, conveyors, compressors, and pumps in surface mining; pumps, compressors, and mixers for in situ production; and refining equipment in upgrading [12]. Heat is extensively used in processes such as bitumen processing in surface mining, steam methane reforming in bitumen upgrading, and steam generation for in situ production.

Cogenerating electricity with steam can offer significant efficiency improvements compared to producing the two separately. Cogeneration can typically achieve 90% overall thermal efficiency, while producing steam and electricity separately is around 85% and 54% efficient, respectively [136]. Cogeneration is often an attractive option to oil sands producers given the abundant amount of waste heat from steam generation and the ability to consume less costly self-produced electricity. Producers have stated that the key advantages of cogeneration are improved power reliability and cost performance of operations [137]. Between 2000 and 2015, the electricity generation capacity from oil sands producers grew from 1813 MW to 4528 MW in Alberta [138]. It is expected that oil sands cogeneration capacity will to grow to 5339 MW by 2037 [139].

Another benefit of using cogeneration in oil sands is the improved environmental performance compared to the local grid mix if it is fossil fuel dominated. The Alberta grid currently operates with 36% of its capacity provided from coal-fired power plants [140]. Alberta grid emission levels are 753 $kgCO_2/MWh$ as of 2019 [12], while cogeneration facilities are typically 390 $kgCO_2/MWh$ [46]. Thus, electricity produced from oil sands cogeneration is less GHG-intensive than the Alberta grid, and using the cogenerated electricity for oil sands operations lowers oil sands emissions compared to using grid-sourced electricity. Moreover, exporting excess electricity produced through oil sands cogeneration to the grid lowers the grid intensity and provides an additional revenue stream for oil sands producers.

Because of these benefits, it has been proposed in literature that increasing the amount of oil sands cogeneration would be a cost-effective GHG reduction strategy for the oil sands [46, 47]. Cogeneration was previously identified by Doluweera et al. as a potential near-term option for lowering Alberta's electricity-based GHG emissions and they also suggested that regulatory frameworks should encourage their development while high-emission coal power is still prevalent [48]. Furthermore, the SAGD subsector has been identified in the literature as the key area for cogeneration expansion, with earlier analysis suggesting the high penetration of cogeneration in the subsector could reduce Alberta's GHG emissions from 13% to 26% of 2008 levels by 2030 [49]. However, the Government of Alberta has announced its intention to phase out coal-fired power generation by 2030 and is aiming for 30% renewable electricity generation [50]. The result will be an electricity grid with mostly natural gas and renewably generated electricity, thus lowering the grid factor substantially. The impact that will have on the effectiveness of oil sands cogeneration to reduce GHG emissions is unknown.

To the best of our knowledge, current literature contains very limited studies that investigate oil sands cogeneration for GHG mitigation. Doluweera et al. developed an energy model of a sample SAGD facility with cogeneration using engineering fundamentals and compared the results to the same facility without cogeneration [48]. This study found that a SAGD facility with cogeneration offered near-term emission improvements. The study was limited to assessing cogeneration in a SAGD application in a single scenario. Other subsectors of oil sands production also have significant opportunity to incorporate cogeneration and evaluating only one scenario does not allow for the comparison of different policy options. Ouellette et al. used a deterministic energy model to evaluate the use of cogeneration in 2030 to either meet expected oil sands electricity requirements or exceed electricity requirements by a specified amount [49]. Their study found that cogeneration can offer a 31% reduction in GHG emissions from SAGD facilities operating off-grid electricity at a marginal cost saving of \$14/tCO_2e. The study considered only the SAGD subsector and was limited in that it assumed cogeneration levels rather than determining market penetration based on competing technologies.

This paper addresses the lack of a long-term sector-wide assessment of the GHG abatement potential associated with wide-scale (in situ, surface mining, and upgrading) implementation of cogeneration in the oil sands. A key novelty is that we integrate a techno-economic market penetration model and a bottom-up energy-system model of Canada to evaluate oil sands cogeneration implementation. Through this approach, interactions between oil sands cogeneration development and the Alberta electricity system are accounted for as the system develops.

The results of this study can be used by industry stakeholders and policymakers to identify technology options for sustainable production to better understand the long-term potential of the evaluated technologies and structure policy accordingly. The analysis provides the abatement potential of these technologies to 2050 along with the marginal costs under different possible climate policies. These results are determined by completing the following objectives:

- Development of feasible technology scenarios for cogeneration to be further implemented in oil sands subsectors.
- Development of a market penetration model to determine the rate of those technologies which could be expected to gain market share during the evaluation period.
- Development of associated costs of those technologies which could be expected to gain market share during the evaluation period.
- Integration of the market penetration results into a bottom-up energy accounting model of the Alberta oil sands to quantify the GHG emission reductions compared to the reference scenario over the evaluation period.

7.2 Method

7.2.1 Framework

Figure 7-1 shows the methodological framework of the study. Reference technology data includes the energy intensity and lifetime costs of using that technology. Cogeneration technology options were identified through literature review, and annual costs and energy intensities with respect to production were determined in each subsector. The market penetration potentials of cogeneration technologies were then modelled in defined scenarios to determine annual use. Then, the Long-range Energy Alternatives Planning (LEAP) [37] bottom-up energy model developed by Davis et al. [116], the LEAP-Canada model, was used with the market penetration results to calculate GHG emission abatement potential. The LEAP-Canada model calculates the system-wide impact of changing the levels of cogeneration in the Canadian electricity system, allowing us to compare GHG emissions from a base case to results from cogeneration scenarios. The abatement potential results from the LEAP-Canada model and the marginal cost results from the penetration model were combined to determine the cost per tonne of mitigated CO_2 equivalent GHGs.

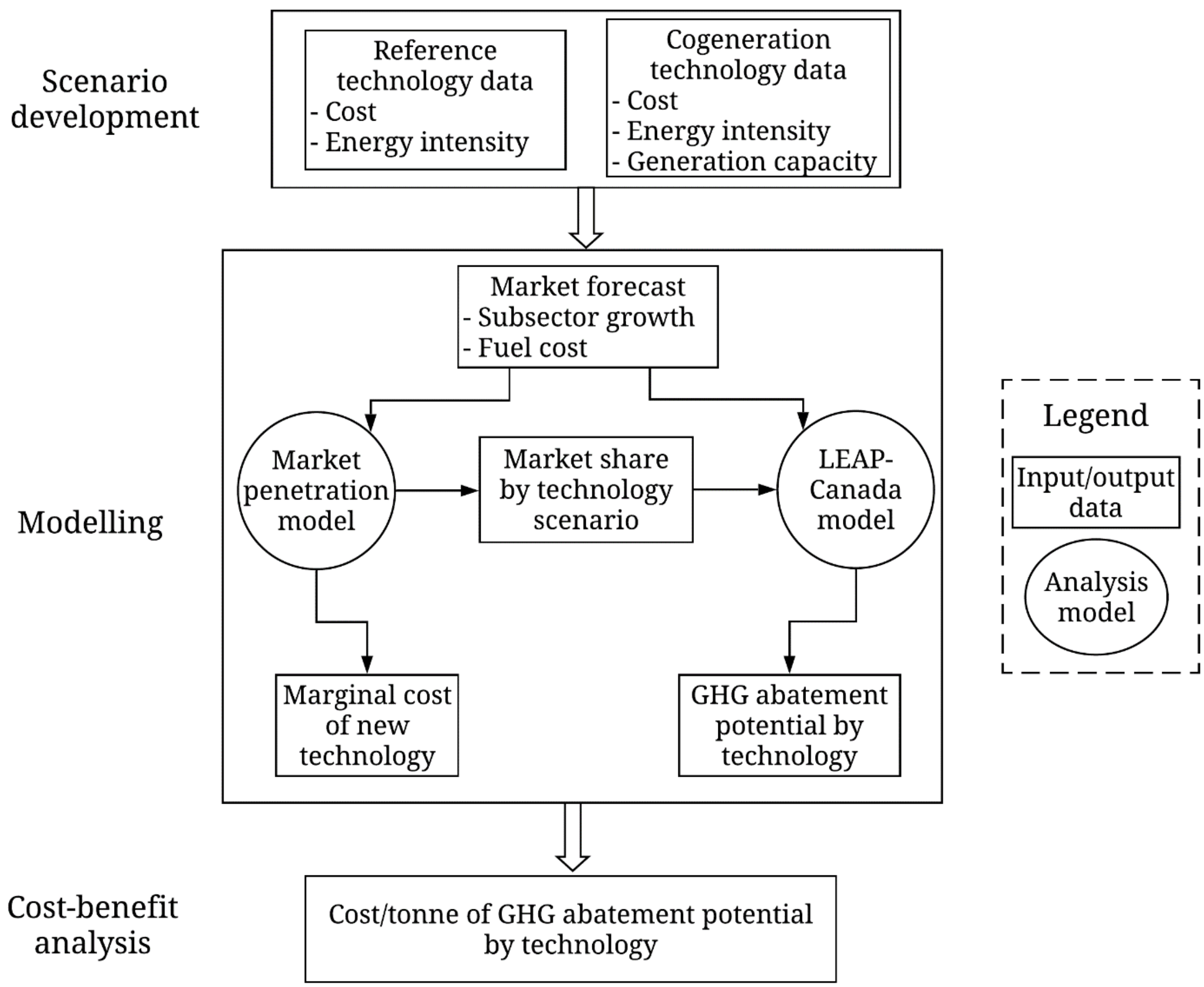


Figure 7-1: Cogeneration study framework

7.2.2 Scenario development

Cogeneration scenarios were developed for the surface mining, in situ, and upgrading subsectors of oil sands production and are described in Table 7-1. Energy requirements and costs for the scenarios were based on literature [141] and updated to 2019 $CAD. The in situ scenario assumes a 30 kbpd SAGD facility with 160 MW of electricity cogeneration capacity, sized to meet the facility heat requirements [119]. Due to the large heat requirement in the form of steam for SAGD facilities [49], the amount of electricity generated in this scenario exceeds the electricity required on site, with 90% of electricity being exported to the grid [119]. This level of generation is in line with other similar sized SAGD projects with cogeneration including Mackay River (207 MW) and Long Lake (170 MW) [142, 143]. The surface mining scenario assumes a 100 kbpd facility, where 50 MW of cogenerated electricity capacity is used, and all the electricity is consumed on site. The upgrading scenario assumes a 100 kbpd upgrading facility that has 15 MW of cogenerated electricity capacity, all of which is consumed on site [119].

The SAGD processes modelled in the reference scenario use natural gas boilers to generate steam that is transported to the injection well. During transportation, some heat is lost and steam is condensed, resulting in a portion of the heating fluid needing to be removed and recycled to the boiler. Four electricity-based technologies were previously investigated in a study that are expected to reduce the quantity of condensed steam to be removed at the injection well [119], and were incorporated as scenarios in the present work. SAGD with cogeneration and steam compressors (SAGD-COG-SC) considers flashing produced water from the SAGD well after primary separation and using an electric steam compressor to reinject it into the boiler steam line. SAGD with cogeneration and well pad boilers (SAGD-COG-WB) investigates using electric well pad boilers to reheat steam that has condensed between the boiler and the injection well because of convective heat losses. Alternatively, in the case of SAGD with cogeneration and well pad compressors (SAGD-COG-WC), the condensed steam is flashed at the well pad and injected back into the steam header using electric compressors. SAGD with cogeneration and electric steam superheaters (SAGD-COG-ES) assesses the effect of using electric heaters to superheat steam coming from the boilers to avoid any condensation due to convective heat loss between the boiler and the injection well. All of these options use additional electricity generated at the SAGD site to potentially improve plant operations and lower GHG emissions from the facility.

Table 7-1: Scenario names and descriptions

Subsector	Scenario name	Description
Steam assisted gravity drainage (SAGD)	Reference	SAGD with no cogeneration
	SAGD-COG	SAGD with cogeneration
	SAGD-COG-SC	SAGD with cogeneration and steam compressors
	SAGD-COG-WB	SAGD with cogeneration and well pad boilers
	SAGD-COG-WC	SAGD with cogeneration and well pad compressors
	SAGD-COG-ES	SAGD with cogeneration and electric steam superheaters
Surface mining	Reference	Surface mine with no cogeneration
	SM-COG	Surface mine with cogeneration
Bitumen upgrading	Reference	Upgrading with no cogeneration
	UPG-COG	Upgrading with cogeneration

Three carbon pricing policies were considered for each scenario, titled “CP0,” “CP30,” and “CP50,” respectively. The first does not apply any costs or benefits related to GHG emissions, allowing technologies to be compared independently of policy decisions. The second, “CP30,” uses a price of \$30/tCO_2e in real 2019 dollars from 2020 to 2050, corresponding to the current industrial carbon pricing [95]. The third, “CP50,” uses a price of \$30/tCO_2e until 2021 and a price of \$50/tCO_2e from 2022 to 2050, in real 2019 dollars, matching the cost of carbon mandated in the federal government’s Pan-Canadian Framework on Clean Growth and Climate Change [4]. The actual taxable emissions are based on process-specific emission benchmarks outlined in previous legislation [8]. This legislation has since been partially replaced with a facility specific emission regulation [144], but still aptly shows the effects of system-wide carbon pricing on the viability of cogeneration technologies in the oil sands. GHG emissions above the given benchmarks are taxable and GHG emissions below them are subject to credits. The market value of the credits varies depending on their availability, but is always less than the taxation rate [8]. In this study, the credits are assumed to be 85% of the taxation rate to account for the difference between credit values and the taxation rate.

7.2.3 Modelling

7.2.3.1 Market penetration model

The market penetration model is based on the technique developed by earlier studies for the energy industry [57, 145]. First, the annualized cost of each scenario, *j*, is calculated using capital costs, operating expenses, carbon costs, and energy costs using Equation 7-1 as presented in Nyboer [35]:

$$\mathrm{LCC_j} = \left(\mathrm{CC_j} \times \frac{i}{1-(1+\mathrm{i})^{-n}}\right) + \mathrm{OC_j} + \mathrm{ECC_j} + \mathrm{EC_j} \tag{7-1}$$

where, LCC_j is the annualized lifetime cost of scenario j, CC_j is the overnight capital cost, *i* is the interest rate, *n* is the technology expected life, OC_j is the annual operation and maintenance costs, ECC_j is the annual emitted carbon cost (if a carbon pricing policy is in place), and EC_j is the annual energy or fuel cost. Economic evaluation is conducted using the 2019 $CAD and an internal rate of return (IRR) of 10% for the interest rate as used in previous GHG mitigation studies [41, 94]. LCC_j values are then entered into the market share calculation shown in Equation 7-2, which represents the market share results from simulating the competition of technologies, assigning an annual market share to each technology *j* also presented in literature [35, 145]:

$$\mathrm{MS_j} = \frac{\mathrm{LCC_j^{-v}}}{\sum_{j=1}^{k} \mathrm{LCC_j^{-v}}} \quad (7\text{-}2)$$

where, MS_j is the market share for technology *j, v* is the cost variance parameter, and k is the number of competing technologies in the subsector being considered. Cost variance parameter values for the energy industry are discussed in literature [35, 145]. A value of 8 is used in this study, and sensitivity is assessed from 6 to 10, a range that Nyboer [35] suggests is applicable to the energy industry. Annual market share is calculated, and the total production assigned to each technology in any given year is determined by multiplying that market share by the forecasted new production. Table 7-2 shows the input values for Equation 7-1 for the reference case and each scenario.

Table 7-2: Cost inputs to Equation 7-1 for each scenario ($/bbl)

Technology	Capital cost (CC)	Operation and maintenance costs (OC)	Energy or fuel cost (EC*)
Reference – SAGD	13.02	7.50	$1.12 {*} P_{NG} + 0.015 {*} P_{ELEC1}$
SAGD-COG	16.38	10.58	$1.57 {*} P_{NG} - 0.081 {*} P_{ELEC2}$
SAGD-COG-SC	17.02	17.29	$0.86 {*} P_{NG} + 0.035 {*} P_{ELEC1}$
SAGD-COG-WB	16.17	11.19	$1.49 {*} P_{NG} - 0.068 {*} P_{ELEC2}$
SAGD-COG-WC	16.53	11.40	$1.51 {*} P_{NG} - 0.068 {*} P_{ELEC2}$
SAGD-COG-ES	16.16	11.19	$1.49 {*} P_{NG} - 0.068 {*} P_{ELEC2}$
Reference - Mining	13.02	8.64	$0.32 {*} P_{NG} + 0.015 {*} P_{ELEC1}$
SM-COG	16.11	8.64	$0.38 {*} P_{NG}$
Reference - Upgrading	16.47	8.64	$0.62 {*} P_{NG} + 0.010 {*} P_{ELEC1}$
UPG-COG	15.87	6.37	$0.63 {*} P_{NG} + 0.006 {*} P_{ELEC1}$

*P_{NG} = price of natural gas; P_{ELEC1} = price of electricity purchased from AB grid; P_{ELEC2} = AB grid forecasted pool price; values and sources for these variables can be found in Appendix C.

The maximum penetration potential for each technology option is determined by the level of growth forecasted in that subsector. The maximum penetration any technology can achieve is equal to the percentage of the total subsector production that is from new production during the evaluation period. Equations 7-1 and 7-2 are used to determine how much of that maximum penetration potential each technology could feasibly take based on their costs. The energy cost component of Equation 7-1 captures any revenues gained through the sale of excess electricity generated through cogeneration. In any situation where a scenario is expected to generate more electricity than is consumed on-site, the annual costs are decreased by the expected revenue from the sale of electricity.

7.2.3.2 LEAP-Alberta model

The model used to evaluate the GHG abatement potential of the cogeneration scenarios was developed by modifying the bottom-up energy systems models developed for Canada [116] and the oil sands [12] in previous work. Katta et al.'s oil sands demand module [12] was integrated with the Alberta portion of Davis et al.'s LEAP-Canada model [116] and the latest forecasts from the National Energy Board (NEB) [13] and Alberta Electricity Systems Operator (AESO) [139] were integrated into the new model. A concise summary of the new model is given below. The reader is referred to both papers for more detailed information on the model.

The LEAP-Alberta model contains bottom-up energy demands that are met by the energy transformation processes used in Alberta for resource extraction and conversion to 2050. The model used for this study is driven by economy-wide electricity demands in Alberta. These electricity demands are calculated from bottom-up device energy-use intensities and sector activity. Energy intensities are given in Katta et al. [12] for the oil sands and in Davis et al. [116] for all other sectors. The time-varying nature of electricity demands is modelled with AESO's

Alberta-specific load curve [146]. From this modelling, the annual peak-load is determined and the required firm electricity supply system capacity is calculated by assuming a 15% reserve margin requirement.

Cogeneration capacity in the LEAP model is determined from the market penetration model's annual results for each scenario. As cogeneration gains market share for a given scenario, the cogeneration capacity in the transformation module of the LEAP-Canada model increases accordingly. The increased cogeneration capacity will decrease the amount of endogenous capacity building within the model to maintain the specified reserve margin. The available capacity of cogeneration plants is assumed to be 75% [116]. The process efficiency of cogenerated electricity is considered to be 61%, which accounts for the energy savings associated with using the waste heat from the steam generation segment [147]. The efficiency used for cogenerated electricity is also tested in the sensitivity analysis. The capacity of renewables is exogenously specified based on the AESO 2019 Long-term Outlook [139]. Natural gas simple cycle and combined cycle are added endogenously to meet the total required system capacity after deducting oil sands cogeneration from the total capacity requirements. The dynamic interactions between oil sands-produced electricity and the Alberta grid system are accounted for in the model. This makes it possible to determine the impact of increased oil sands cogeneration on future electricity GHG emissions in Alberta.

The additional SAGD scenarios incorporating electricity-based equipment were modelled by increasing the electricity energy intensity of the steam generation end-use technology and reducing natural gas end-use energy intensity. The results of these scenarios are discussed in Section 3.

The emissions for electricity generation were calculated in LEAP using IPCC emission factors [1] and feedstock fuel requirements, which were determined by the process efficiency and electricity requirements.

7.2.4 Cost-benefit analysis

Cost-benefit analysis was conducted for each scenario and compared to the reference scenario. Costs are determined by calculating the difference in lifetime cost between the evaluated GHG mitigation scenario and the cost of the reference scenario, and benefits are determined by the abatement potential, or the GHG emissions during the evaluation period in the reference case subtracted from the emissions in the considered scenario. This calculation is shown in Equation 7-3:

$$Marginal\ cost_j\ [\$/tonne] = \sum_{n=i}^{n} \frac{AC_{jn} - AC_{REFn}}{E_{REFn} - E_{jn}} \tag{7-3}$$

where $Marginal\ cost_j$ is the marginal cost of scenario j per tonne of GHG emission abatement, AC_{jn} is the annual monetary cost of scenario j in year n, AC_{REFn} is the annual monetary cost of the reference scenario in year n, E_{REFn} is the GHG emissions associated with the reference scenario in year n, and E_{jn} is the GHG emissions associated with the scenario j in year n.

7.2.5 Sensitivity analysis

Sensitivity analysis was conducted on the key parameters that are subject to variability in the study. The cost variance parameter was tested across the range from 6 to 10, to determine the effects on market penetration modeling results based on suggested range in the literature [35]. The IRR used to evaluate expenses was adjusted by +/- 5% to determine the sensitivity of the results to perceived investment risk. Natural gas prices inherently fluctuate in the global and local markets and are difficult to predict; therefore, the results were tested by +/- 20% of forecasted prices. Expected growth of the oil sands industry is also dependent on many factors including global energy demand, access to market through shipping capacity from western Canada, and government requirements for expansion. Given these variables, forecasted growth was changed by +/- 20% to better understand sensitivity to abatement potential results. Cogeneration efficiency is varied by +/- 10% to understand the impact the facility efficiency has on the final results.

7.3 Results

7.3.1 Market penetration results

2030 and 2050 market penetration results for further integration of cogeneration into the in situ - SAGD, surface mining, and upgrading subsectors are shown in Figure 7-2. The SAGD subsector showed the highest maximum penetration potential at 45% in 2030, of which the cogeneration scenario captured 21.2%, 22.0%, and 22.1% in the CP0, CP30, and CP50 scenarios because of the scenario's improved cost performance compared to the reference technology. The mining subsector had a maximum of 23% penetration potential, with all growth occurring before 2030, and the cogeneration scenarios captured 6.2% at CP0 and 6.4% at CP30 and CP50 carbon pricing. The mining cogeneration gained a smaller portion of the available penetration potential because the lower heat requirements in surface mining operations provide less opportunity for cogeneration to generate revenue through the sale of excess electricity. Finally, the upgrading subsector had a maximum of 18% available market penetration potential in the evaluation period, and cogeneration scenarios captured 9.0% with CP0 and CP30 carbon pricing and 9.1% with CP50 carbon pricing in 2030, gaining approximately half the available penetration potential because of the strong cost advantages of cogeneration, especially through the sale of excess electricity. No changes were observed between the 2030 and 2050 penetration results for the surface mining and upgrading subsectors; this is because expected growth in those areas is projected to occur before 2030. SAGD scenarios averaged a 4.3% penetration increase from 2030 to 2050. The results show that carbon pricing has little impact on the penetration of these technologies, which increases on average by 0.4% increase from the CP0 to the CP50 carbon pricing across scenarios. The main reason carbon pricing has little impact on economic performance in these technologies is that capital costs and operating costs are much more significant than emission costs (calculated in Equation 7-1 and shown in Table 7-2)

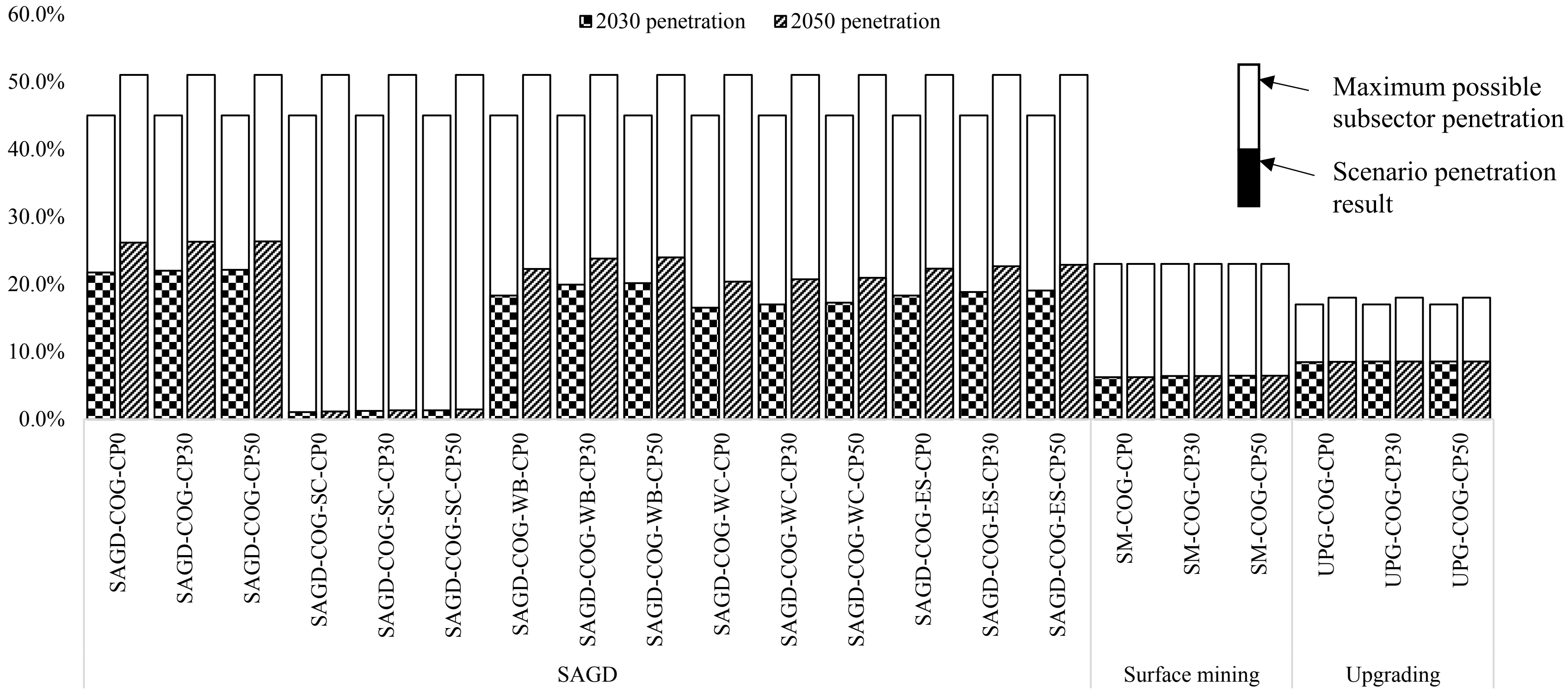


Figure 7-2: 2050 market penetration results for basic cogeneration scenarios

Figure 7-2 also shows the results from the electrification scenarios in the SAGD subsector. The steam compressor scenario offered the most substantial reduction in natural gas consumption at 55% of the SAGD cogeneration scenario but required approximately 9 times the electricity. The well pad boilers and steam superheater technologies had similar energy performances, that is, they achieved a 5% reduction in natural gas but required a 90% increase in electricity demand. The well pad compressor scenario resulted in a 4% reduction in natural gas demand and an 85% increase in electricity demand [119]. Because of the cost increases and lack of significant performance or environmental gains, none of the considered options outperformed the SAGD cogeneration scenario. The electric steam compressor scenarios (COG-SAGD-SC scenarios) performed the worst because of the high operating expenses expected, gaining no more than 1.3% market share by 2050. Electric well pad boilers (COG-SAGD-WB scenarios) performed most closely to the basic SAGD cogeneration scenario, gaining 22.3%, 23.8%, and 24.0% in the CP0, CP30, and CP50 scenarios, respectively, by 2050. These scenarios attained on average 2.3% less penetration than the SAGD cogeneration scenario. Electric well pad compressors and electric steam superheaters attained 4.8% and 3.0% less market penetration on average than the SAGD cogeneration scenarios, respectively. These results show that the benefits of incorporating electricity-consuming technologies to improve SAGD plant performance do not outweigh the expected benefits of exporting that electricity for sale at the technology's current cost and performance levels.

7.3.2 GHG emission abatement potential

The cumulative GHG abatement potential of the cogeneration scenarios for all three subsectors is shown for each year in the evaluation period in Figure 7-3. GHG emission abatement potential in these scenarios comes from reduced electricity demand GHG emissions. Cumulative GHG mitigation potential from the three considered subsectors was 22.6 Mt in 2030 and 40.0 Mt in 2050; this shows the result of increased cogeneration penetration through the evaluation period. The SAGD subsector contributed 36.8 Mt of the 2050 abatement potential (92% of the total), reflecting the impact that high growth predictions and the large power export potential of those facilities can have on grid electricity GHG emissions in Canada. However, if these GHG emission reductions were allocated to the oil sands industry, they would represent a decrease of only 1.1% from the reference case GHG emissions through the evaluation period. Additionally, cogeneration will be a source of GHG abatement as long as coal plants and simple cycle natural gas plants are being replaced but contributes GHG emissions when compared to renewable options. Despite the limited impact on total GHG emissions of the oil sands industry, the technology represents a distinct efficiency gain that results in abated GHG emissions and shows good potential to penetrate the market in the future due to the technology's strong cost performance.

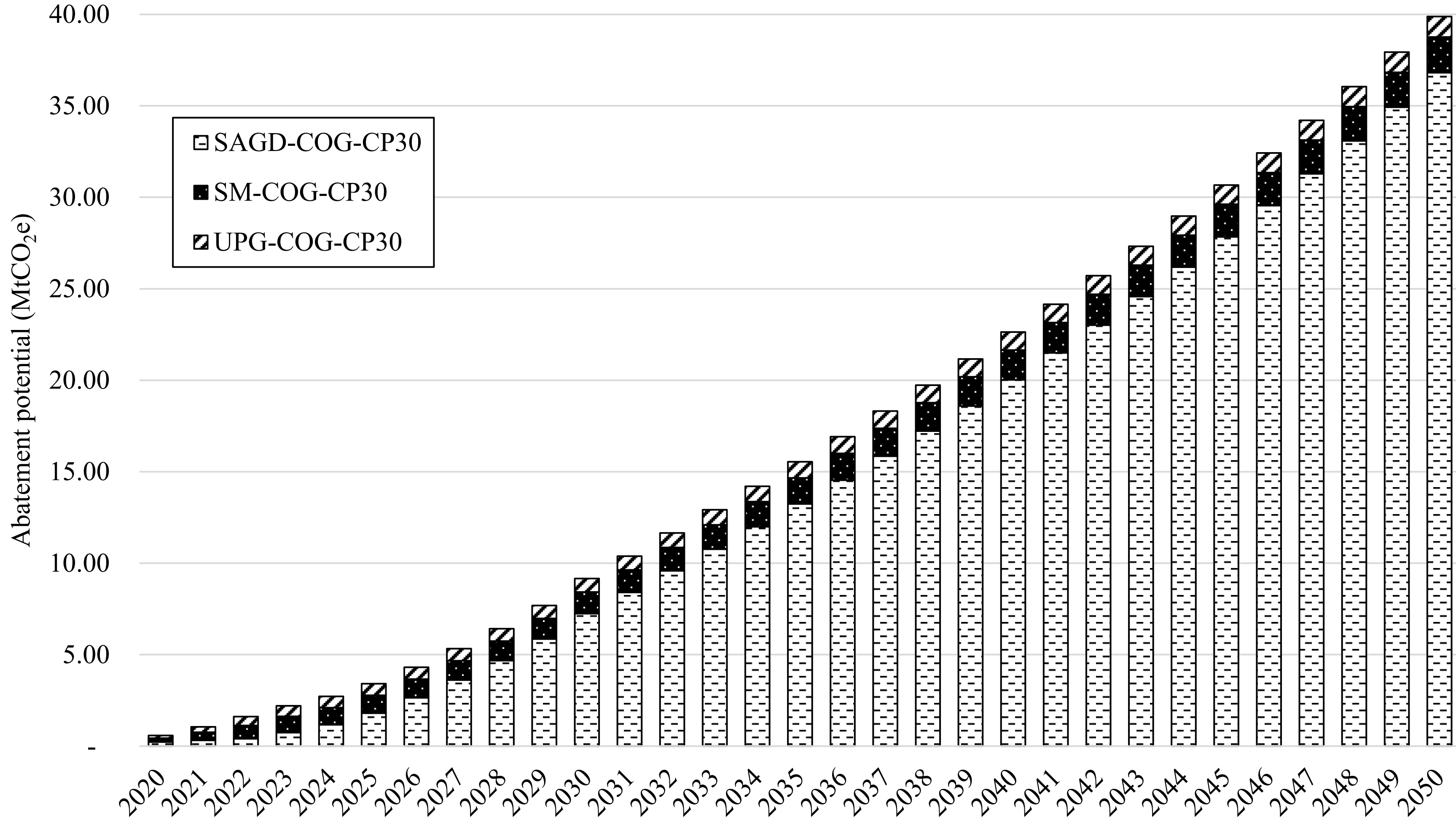
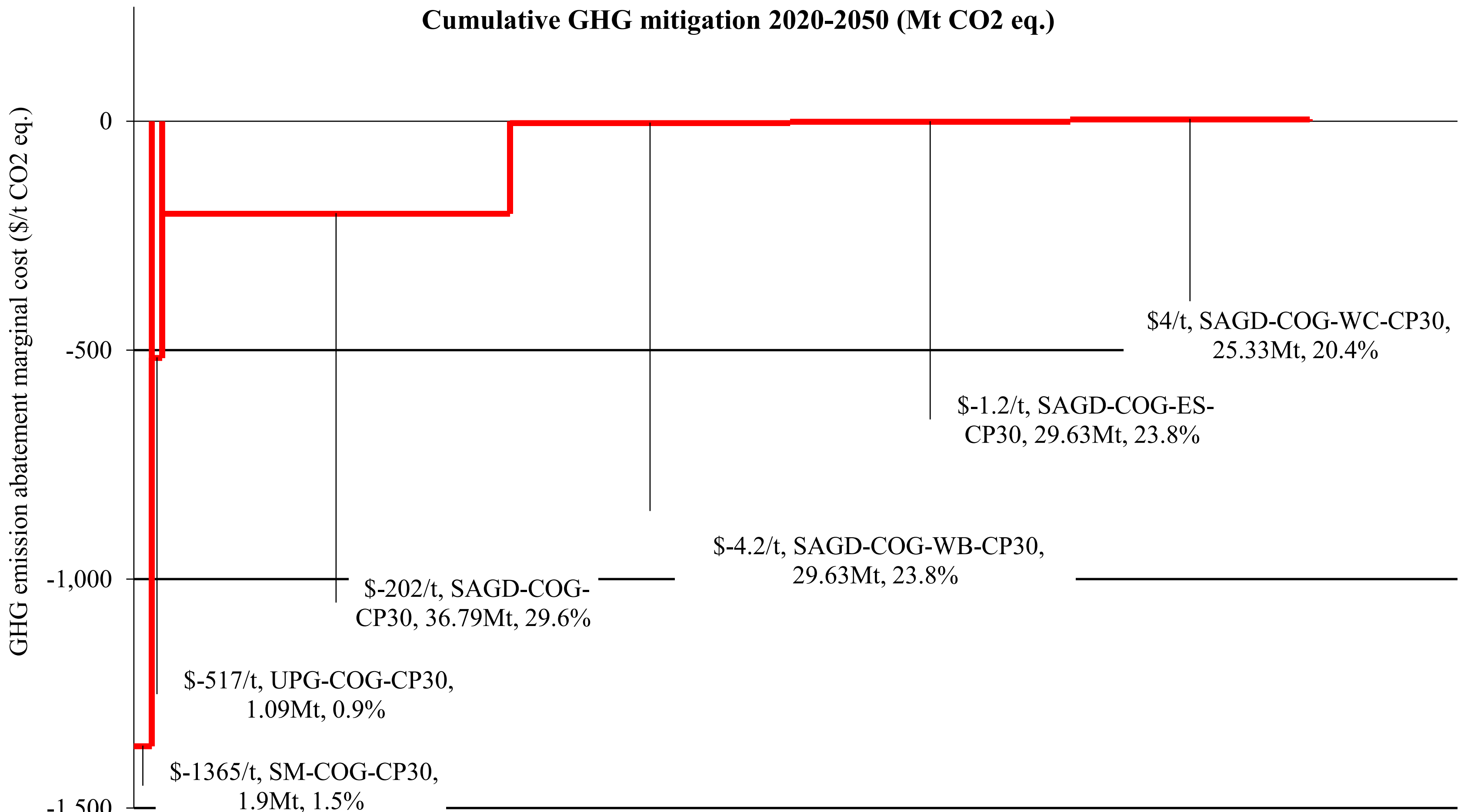


Figure 7-3: Cumulative emission abatement potential from 2020

7.3.3 Marginal GHG emission abatement cost curves

Despite the limited long-term abatement potential of cogeneration technologies, cost calculations show that cogeneration is cost-effective and provides a lower GHG-emitting source of electricity for oil sands operations. Figure 7-4 shows the scenario cost curve results for cogeneration and electric equipment scenarios for the 2020-2050 evaluation period. Every cogeneration scenario considered provides GHG abatement with expected cost savings over the evaluation period at CP30 conditions. Carbon pricing had a limited impact on abatement potential in the upgrading and mining subsector cogeneration scenarios; the mining subsector results varied by less than 4% and the upgrading subsector scenarios by less than 1% under different carbon prices. This is mainly due to the low penetration of the scenarios following minimal forecasted growth in those subsectors. Marginal cost results showed strong cost saving opportunities for these subsectors; however, this is partially due to the low abatement potential, as calculated in Equation 7-3. Marginal cost results for the SAGD subsector forecasted cost savings through the evaluation period, though less substantial than the upgrading and mining subsector scenarios. Carbon pricing resulted in a \$27/tCO_2e marginal cost decrease from CP0 to CP50. The abatement potential is largely due to the greater forecasted growth in the SAGD subsector, allowing for greater opportunity for technology penetration. Because of the higher abatement potential, the SAGD subsector scenarios likely still offer the best opportunities to reduce GHG emissions from electricity consumption in oil sands processes, though increased cogeneration can be implemented simultaneously across subsectors, and cost savings are forecasted in all of them.

GHG Abatement potential and marginal cost results from the SAGD subsector electrification scenarios, shown in Figure 7-4, can be compared to the basic scenarios' results in the SAGD subsector (SAGD-COG scenarios) in terms of performance. The results show that all of the electrification options performed more poorly than the SAGD-COG scenarios in both abatement potential and cost. This is because the increased costs of the added electric equipment lower performance and therefore the equipment gains less market share. The conclusion that can be drawn is that the efficiencies gained from the electric equipment do not sufficiently reduce GHG emissions from the plant to justify their use. The top performing technology of those considered was the well pad boilers used to re-boil steam that had condensed between the main boiler and the injection well. Using this technology in conjunction with cogeneration at a SAGD site provided 22.8 Mt of abatement potential at -$4.20/t marginal cost in CP30 conditions. Compared to the basic SAGD cogeneration scenario at the same carbon price, this is a 3.1 Mt reduction in abatement potential and a $282/t increase in marginal cost.



* Notes
NPV of costs discounted to 2019

Figure 7-4: GHG mitigation cost curves for scenarios under CP30 conditions from 2020 to 2050

7.3.4 Sensitivity analysis

The sensitivity of key results to changes in specified parameters including the cost variance parameter used in market penetration modelling, IRR, forecasted natural gas prices, and forecasted market growth was tested. The results of the sensitivity analysis are presented for CP30 scenarios. Regardless of carbon price, the scenarios follow a similar trend in each case. Full sensitivity analysis results are available in the Appendix D.

Figure 7-5 shows the sensitivity of 2050 market share results to changes in the cost variance parameter over the suggested range of values for the energy industry [35]. No significant differences in results were observed across the range of cost variance values, and the average difference in 2050 market share is 0.7%.

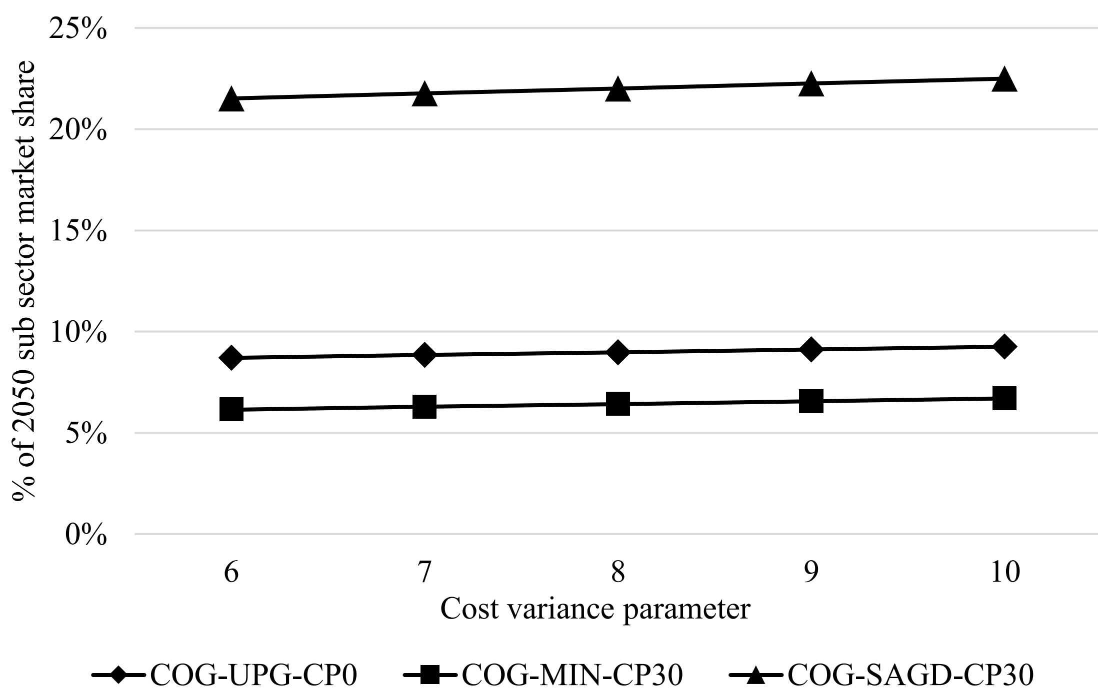


Figure 7-5: Sensitivity of 2050 market share to changes in the cost variance parameter

Figure 7-6 shows the abatement potential results for the range of IRR values used to evaluate project costs in each scenario. SAGD scenario results were significantly impacted by changes in the IRR. At 5% IRR, abatement potential increased by 68% from the base result, while at 15% IRR the technology provided no abatement potential. This is because the technology penetrates the market at a much slower rate when a higher IRR value is used. 2050 market penetration levels were as high as 35% at a 5% IRR and as low as 8% at a 15% IRR. It is expected that SAGD would be most impacted by changes to the IRR because the SAGD process has the highest steam requirement and therefore the highest capital costs associated with adding cogeneration plants. The higher capital costs result in a larger price change when the IRR is increased. Surface mining and upgrading were less significantly impacted when compared to the SAGD scenarios, where abatement potential increased by an average of 8% of base values at 5% IRR and decreased by an average of 24% of base values at 15% IRR. Despite the lower impact of IRR changes to the surface mining and upgrading scenarios, the changes still have a significant impact on results. It is clear from all the results, then, that the perceived financial risk of adding cogeneration to facilities plays a major role in the technology's financial viability and subsequent abatement potential from changing technology penetration rate.

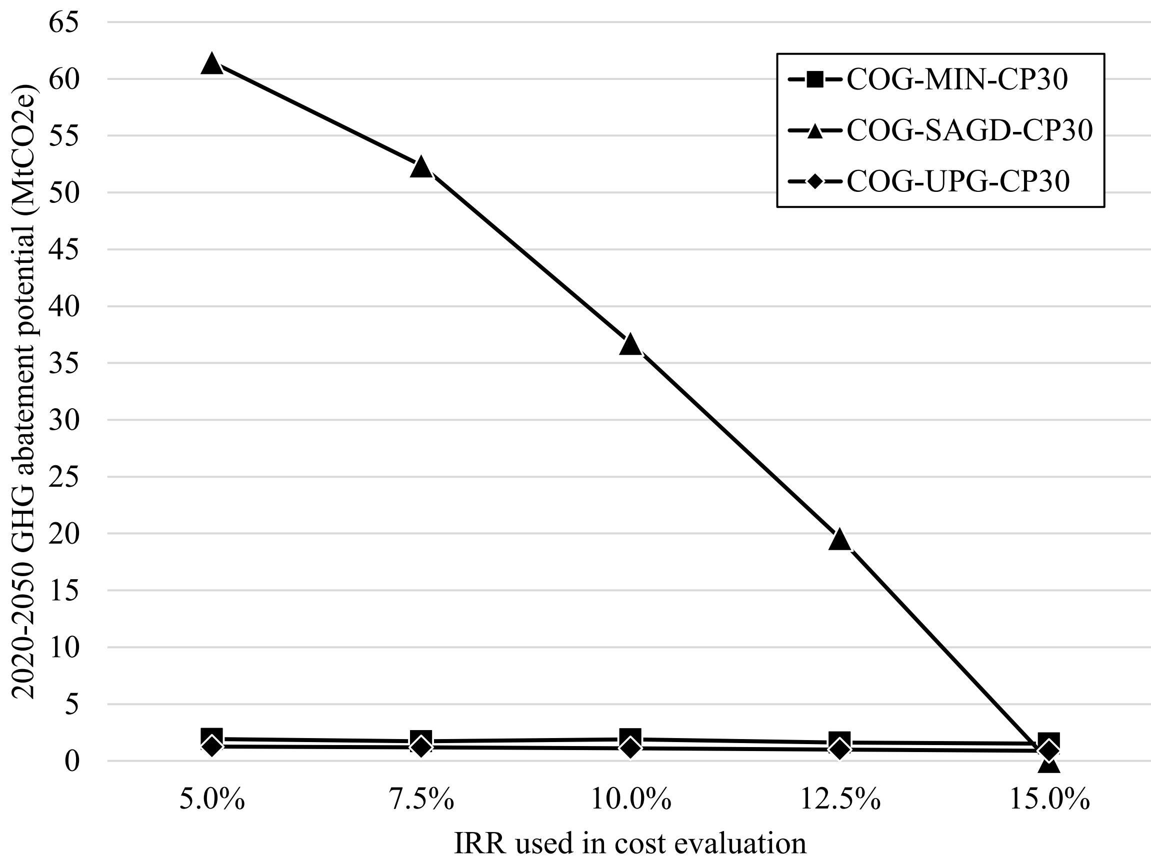


Figure 7-6: Sensitivity of GHG abatement potential to changes in IRR

The sensitivity of GHG abatement potential to changes in forecasted natural gas prices for each technology was also tested and the results are shown in Figure 7-7. Annual natural gas prices are based on the NEB forecast [13] and are available in Appendix A. The upgrading scenarios showed no change across the range of price modifications tested, while the mining scenarios had a 1% decrease in GHG abatement potential from the lowest natural gas price modification to the highest. This result can be attributed to the similar levels of natural gas consumption between the reference scenario and the cogeneration scenarios. The SAGD scenario showed the greatest sensitivity; the scenario's GHG abatement potential increased by 2.9 Mt when forecasted natural gas prices decreased by 20% and decreased by 2.7 Mt when forecasted natural gas prices increased by 20%. As with the IRR sensitivity, the larger relative size of cogeneration facilities required to meet the high heat requirement of SAGD is the main reason for this change. The extra natural gas required to operate the cogeneration facilities is minimal in the upgrading and surface mining scenarios, but more substantial in SAGD, leading to a greater impact from changes in natural gas prices.

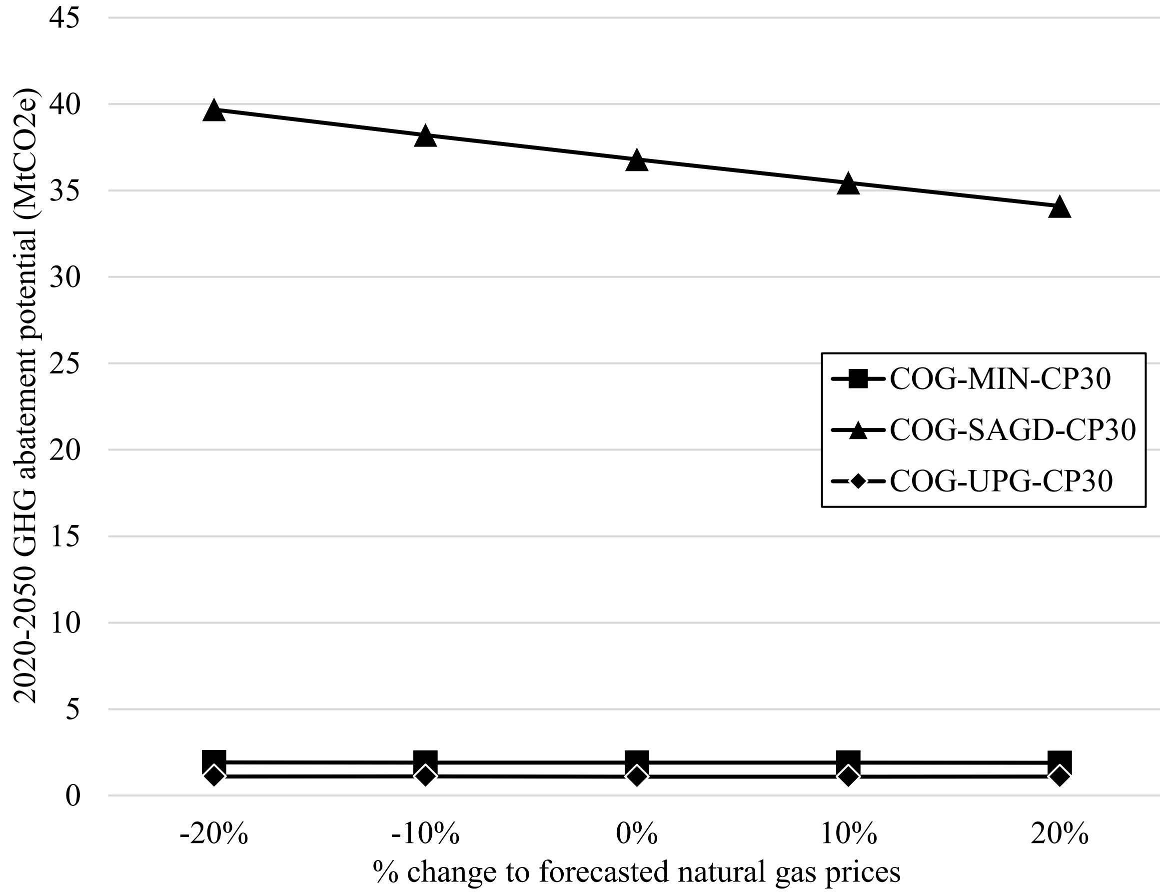


Figure 7-7: Sensitivity of GHG abatement potential to changes in the forecasted natural gas price

GHG abatement potential results were also tested in relation to changes to the forecasted market growth, and the results are shown in Figure 7-8. The SAGD scenarios were most sensitive to changes in market growth, especially to decreases; abatement potential was as low as 26.6 Mt and as high as 47.4 Mt from a base value of 36.8 Mt. The upgrading and mining scenarios averaged a 10% change in abatement potential.

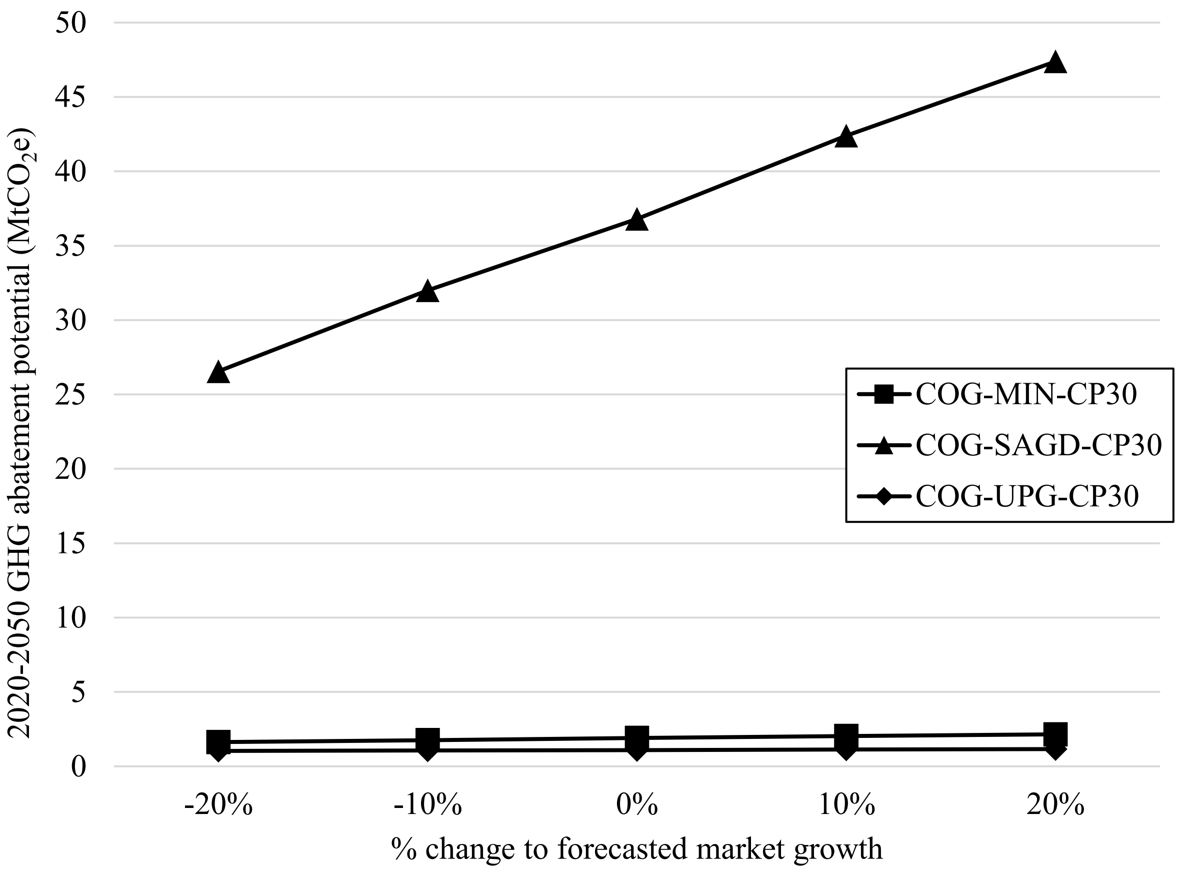


Figure 7-8: Sensitivity of GHG abatement potential to changes in forecasted market growth

The base efficiency value of the cogeneration plants (61%) was varied by +/- 10% and the abatement potential results are shown in Figure 7-9. All scenarios showed significant variation in the expected GHG abatement potential across this range. The SAGD scenario varied from 3.2 Mt to 60.9 Mt at the low to high efficiency, respectively, from a base value of 36.8 Mt. The surface mining and upgrading scenarios decreased to 27% of the base value at the lowest efficiency and increased to 150% of the base value at the highest efficiency, on average. The large variation is expected due to most of the abatement potential coming from the efficiency cogeneration offers over electricity generated by combined cycle natural gas plants (efficiency of 51%) and simple cycle natural gas plants (efficiency of 38%). When the cogeneration plant efficiency is decreased to 51% there is no advantage over combined cycle plants any longer, reducing GHG abatement potential considerably. These results show the importance of understanding the facility efficiencies with regard to the other power options available.

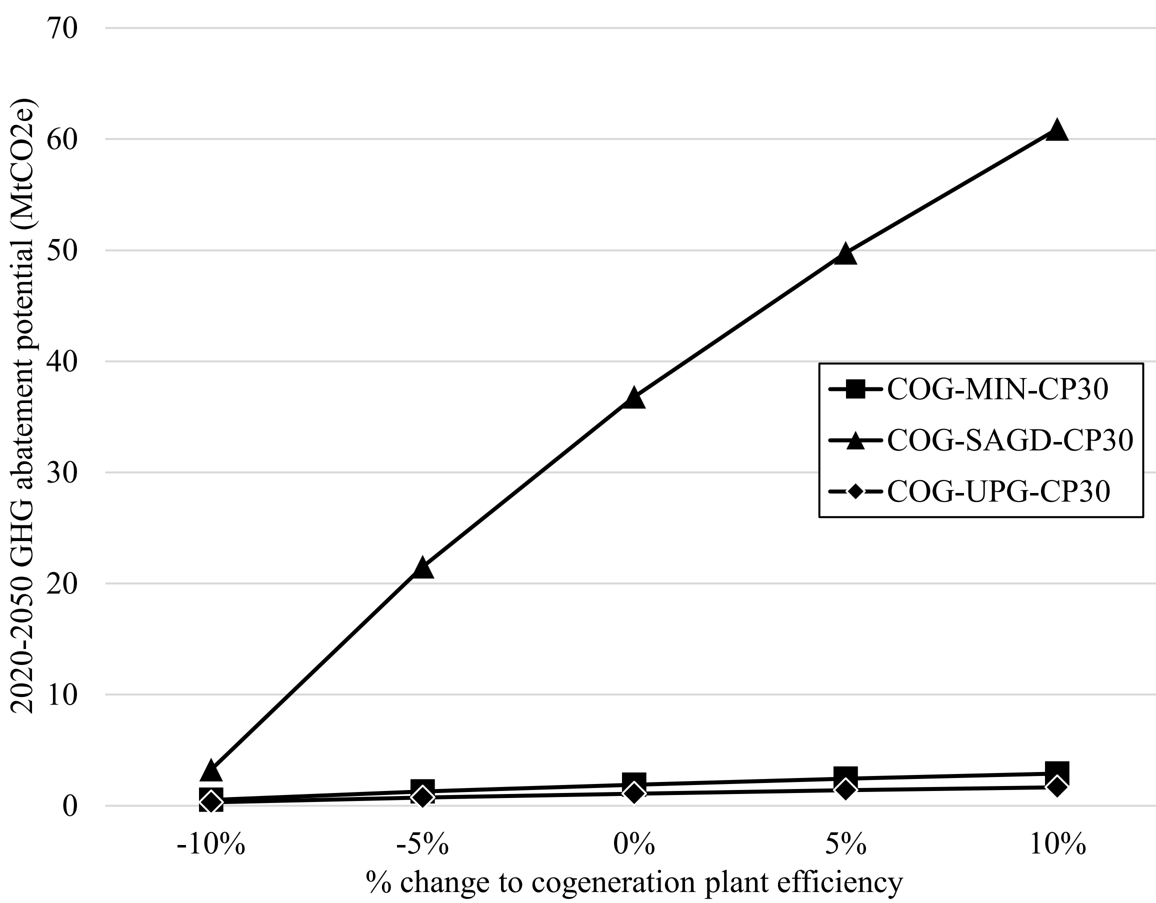


Figure 7-9: Sensitivity of GHG abatement potential to changes in cogeneration plant efficiency

In summary, results were most sensitive to the cogeneration plant efficiency and the IRR selected for evaluation. These findings suggest the having a strong understanding of plant performance as compared to other electricity generation sources is key to the GHG abatement potential of cogeneration technologies and also shows the importance of using the most efficient equipment possible. The sensitivity of results to IRR shows the importance of a low perceived risk for the technology to succeed. One of the key variables for evaluating the risk of a cogeneration facility is the profit associated with sold electricity, therefore transparent policies around grid pricing are important for understanding that risk and selecting an appropriate value.

7.3.5 Limitations

There are some limitations to the methods and results presented in this paper that are important to understand. First, forecasted market growth, commodity prices, and technology performance are all based on the best currently available published studies, but those parameters are determined using inputs that can vary unexpectedly. Natural gas prices and crude oil prices are both influenced by global and local phenomena that are difficult to predict and those prices impact the expected growth and costs associated with oil sands production. Sensitivity analysis was conducted on the key variables to understand the impact of changes to these values, but the model must be updated as the market develops.

Market penetration modelling is conducted using a hybrid diffusion and cost model. In this model it is assumed that technology penetration rates can be modelled using a symmetrical logit curve based on the technology cost compared to other options. The curve captures the typical behaviors in the market of slow initial uptake followed by a maximum penetration rate as the technology reaches cost competitiveness, and finally a period of slow penetration as the market becomes saturated. While this general behavior is understood and observable, the technology is unlikely to follow the perfectly symmetrical path the model uses. Technologies also often develop through breakthroughs that result in sharp performance improvements. This study only considers the current understanding of the technology; the model would need to be updated if significant performance improvements are identified.

Current carbon pricing regulations are difficult to model accurately, specifically to capture an appropriate value of carbon credits. Currently, carbon credits are received for processes operating below the industry benchmark GHG emission factors. These credits can then be sold to producers who operate above the benchmark at some value lower than the taxation rate. There is no data available for average carbon credit market values, so this study assumes that they are sold at 85% of the taxation rate and conducts sensitivity analysis to understand the result if it is different.

7.4 Conclusion

Cogeneration has played a key role in increasing operating efficiency while reducing GHG emissions from the oil sands industry and producing electricity with a significantly lower GHG intensity than grid electricity. In this study, three different oil sands subsectors were evaluated for the years 2020 to 2050 for the potential to increase cogeneration penetration as a way of reducing GHG emissions from the industry. Four additional scenarios in the SAGD subsector were evaluated over the same period to determine the potential for electricity-based technologies to further reduce GHG emissions from the SAGD subsector. These scenarios were all evaluated under three different carbon pricing policies; thus 21 scenarios were assessed. A novel analysis of cogeneration in the oil sands was conducted using a combined market penetration and bottom-up energy accounting model. The results offer valuable insights into the long-range cost and environmental performance possible by increasing cogeneration in the oil sands industry. Market penetration modeling results showed that steam-assisted gravity drainage (SAGD) cogeneration offers the greatest potential to gain market share, up to 22.1%, primarily because of the significant growth expected in that subsector during the evaluation period. Correspondingly, SAGD scenarios offer up to 37.0 $MtCO_2e$ of GHG abatement potential in the evaluation period, while surface mining and upgrading offer up to 1.9 Mt and 1.1 Mt. Cumulatively, these results represent a 1.1% reduction in emissions for the oil sands industry when compared to our reference scenario. We found that consistent GHG savings can be achieved annually throughout the 2020-2050 evaluation period. Cogeneration scenarios in the SAGD, upgrading, and surface mining subsectors were all found to sustain a net cost benefit by 2050 compared to development without cogeneration. These results hold true regardless of the considered carbon prices and increasing carbon prices had only a minor effect on the results for these scenarios. The results from scenarios incorporating additional electrical equipment into the SAGD process do not show enough additional process efficiency to justify their costs. These results may be useful to oil sands stakeholders and government policymakers for long-term planning.

8 Conclusions and recommendations

8.1 Conclusions

In this research, a novel modelling framework was developed to forecast the potential for low GHG emission technologies to penetrate the Alberta oil sands industry and to predict their GHG abatement potential and marginal costs from 2020 to 2050. The literature lacks a comprehensive analysis of technology options available to bitumen producers for reducing process GHG emissions that incorporates market penetration analysis and long-term GHG abatement potential. Here, the performance of several technologies that have the potential to reduce GHG emissions from current bitumen production processes in the Alberta oil sands was compared. This study is the first comprehensive analysis of technology options available for the oil sands conducted using a consistent framework so that results can be easily compared. The framework incorporates market penetration principles using a cost model and bottom-up energy accounting to determine GHG emissions. The model is data intensive, using historic data to validate verifiable results and published forecasts to determine future activity levels.

Four classes of technologies were evaluated in the framework: renewable/low carbon energy, carbon capture and storage, advanced extraction, and cogeneration technologies. Feasible scenarios were developed for each using recent research to ensure the cost and performance used reflects current and future conditions in Alberta. These technologies were also evaluated under different environmental regulations to capture policy frameworks reflecting current legislation or published government plans to ensure policy cost implications were captured in the results. 84 scenarios were evaluated through 24 unique GHG-reducing technologies spanning 5 oil sands subsectors under 3 different carbon policy frameworks. In each case, market penetration potential, GHG abatement potential, and marginal GHG abatement costs were determined in relation to a reference scenario representing current practices. Annual GHG emissions and annual abatement by technology class are shown in Figure 8-1. GHG abatement potential and marginal GHG abatement cost results for all the scenarios considered in this study are presented in Figure 8-2. The same results for scenarios that can be deployed simultaneously (only the top GHG abatement scenario results shown for scenarios considering the same technology under different policies or contexts) are shown in Figure 8-3.

Ten renewable/low carbon energy technologies were evaluated spanning the major oil sands processes of upgrading hydrogen production, in situ steam production, surface mining process heat, and dedicated electricity production. The results show that feasible market penetration can lead to 74 Mt of GHG emission abatement potential at \$9.32/tCO_2e. 72% of the GHG abatement potential is the result of a single scenario incorporating small modular nuclear reactors into in situ bitumen production at a marginal cost of \$5.16/tCO_2e. The only scenario to show long-term cost savings is through nuclear electricity production, where 5 Mt of GHG abatement potential is possible at -\$11.91/tCO_2e. These results suggest that of the renewable/low carbon energy options, nuclear energy options perform the best, both in terms of GHG abatement potential and marginal costs. Many renewable energy technologies, despite their strong GHG emission reduction potential, are too expensive to compete with current oil sands processes (i.e., wind, hydro, and geothermal options). Nuclear options, which are the most cost effective, gain most of their market share after 2030, suggesting that these technologies are more likely candidates for long-term strategies.

Carbon capture, utilization, and storage technologies were evaluated by looking at 4 different technologies and 2 different carbon storage processes, one of which involves the sale of captured carbon for utilization before storage. The results from the top performing scenario show that feasible market penetration can result in 232 Mt of GHG abatement potential at marginal costs of -$28/tCO_2e. The best performing technology is oxyfuel boilers used for in situ bitumen production and fueled by produced bitumen. The results from the penetration model show that all CCUS scenarios will gain over half their 2050 market penetration by the year 2030, suggesting that they could be deployed in the near term. Scenarios in which it was assumed captured carbon could be sold and utilized before storage have a significant cost advantage, which leads to increased penetration and up to 61 Mt of additional abatement potential, suggesting that this storage option should be explored further.

Three different emerging extraction processes were evaluated in the in situ subsector to replace the SAGD process. Feasible market penetration of these technologies can lead to 267 Mt of abatement potential at -$47/tCO_2e marginal cost, all using some form of hydrocarbon solvent to assist in the mobilization of bitumen. All technology scenarios are expected to result in some level of cost savings over the evaluation period, suggesting that all 3 techniques should continue to be investigated. These technologies are still in the early stages of development, so sensitivity analysis was conducted over wide margins for key factors impacting the cost and performance of the technology, and the results show that the technologies are particularly sensitive to the IRR chosen for the cost evaluation and forecasted natural gas prices. These results indicate that efforts to research these technologies further to gain a better understanding of energy requirements and reduce the perceived risk of investment could improve their financial viability.

The impact of increased cogeneration of electricity in 3 different subsectors was analyzed as well as the impact of incorporating 4 different electrical equipment technologies with cogeneration in the in situ subsector. Market penetration results from these scenarios suggested that up to 40 Mt of abatement potential is feasibly available at -\$266/tCO_2e marginal costs. Cogeneration technologies were found to provide consistent abatement potential throughout the evaluation period due to emission levels from cogeneration plants being significantly lower than coal fired plants and simple cycle natural gas plants and marginally lower than combined cycle natural gas plants. These results suggest that cogeneration can be an effective means of reducing emissions from electricity consumption when grid electricity is supplied any of those options. The abatement potential identified represents 1.1% of total oil sands emissions during the evaluation period.

Figure 8-1 shows the annual emission forecasts for the business-as-usual scenario and the emissions that could be abated through each technology class. Figure 8-2 and Figure 8-3 provide a comparison of the relative performance of each over the full evaluation period; advanced extraction and cogeneration technologies offer the best marginal cost performance, CCUS scenarios the greatest GHG abatement potential, and renewable energy options the highest marginal costs. Mitigation potential from cogeneration technologies was found to offer a less emission intensive electricity source than coal fired plants, simple cycle natural gas plants, and combined cycle natural gas plants, making cogeneration a strong GHG abatement option for electricity generation while these other technologies are still in use. Carbon capture, utilization, and storage options offer the highest levels of mitigation potential and will gain the majority of their market share before 2030, suggesting again that they are a strong near-term solution. Renewable and low carbon energy options offer lower mitigation potentials and are expected to gain most of their market share after 2030, mostly with nuclear energy technologies, suggesting they are better suited for application later. Finally, emerging advanced extraction technologies all show promise with expected long-term cost savings, even when sensitivity to changes in costs were tested over a wide range, suggesting that research should continue into these technologies to better understand their performance potential. Carbon pricing has the greatest impact on renewable and low carbon energy technologies, with mitigation potential increasing by 92 Mt and marginal costs dropping by \$18/tCO_2e from CP0 to CP50. The impact of carbon pricing on the other technology classes is less pronounced and shows an increase in abatement potential of less than a 15%. Overall, these results should help industry stakeholders and policymakers gain a quantified understanding of the current state of technology options for reducing GHG emissions from oil sands activities. The results presented here can be used to promote technology options that offer the greatest long-term impact and financial performance as well as gain an understanding of the impacts of policies such as carbon pricing on specific technologies.

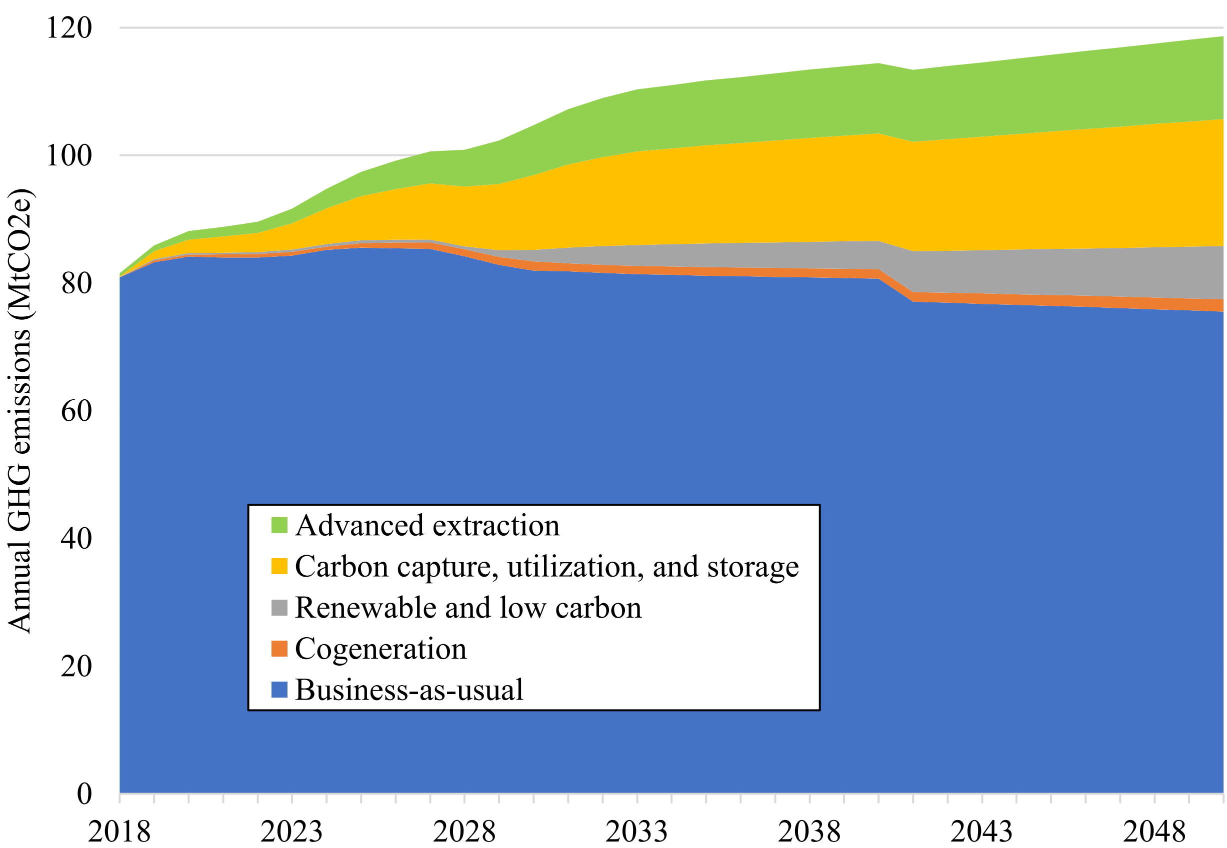
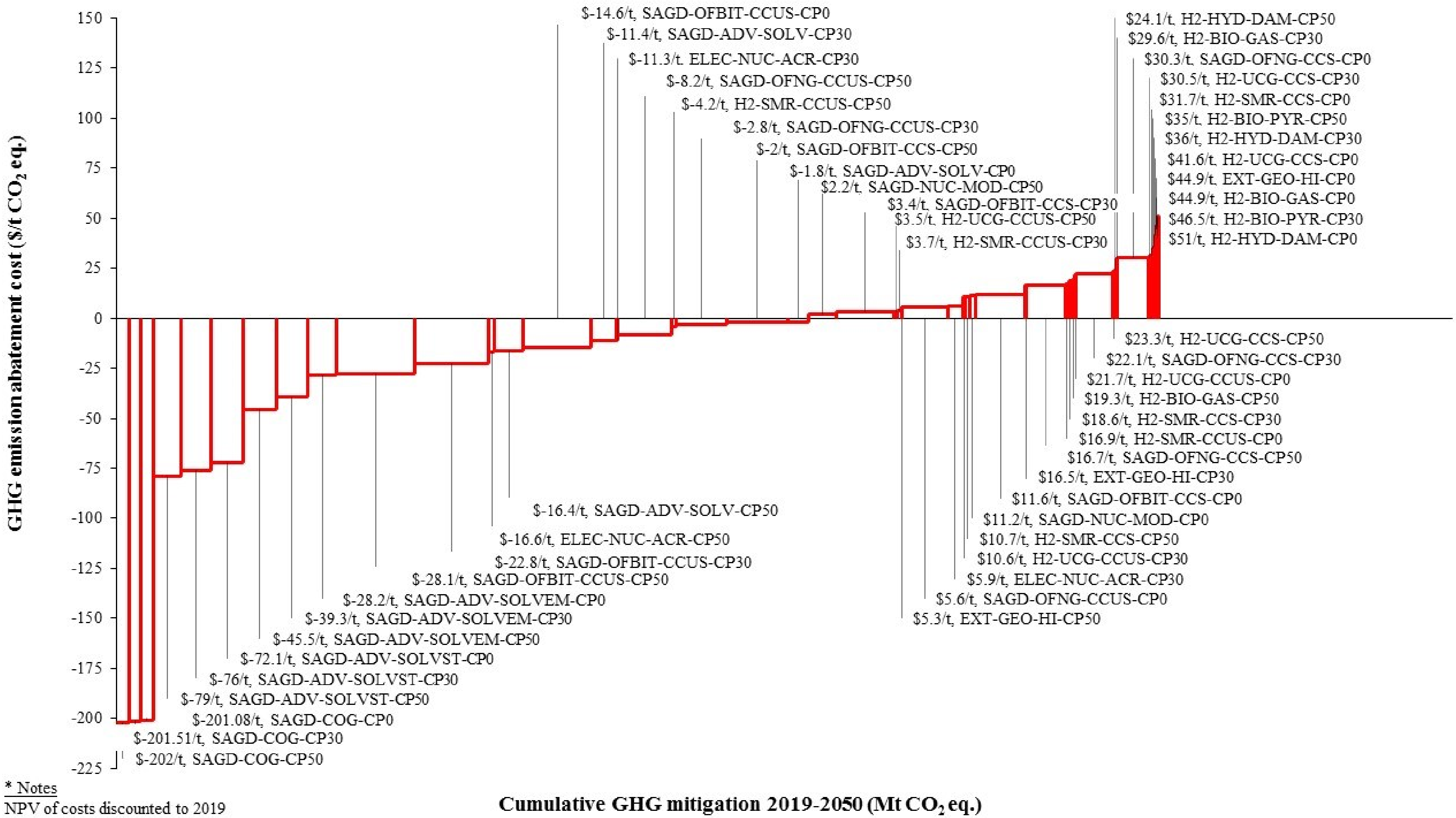


Figure 8-1: Annual GHG emission reduction potential by technology class



* Notes
NPV of costs discounted to 2019

Figure 8-2: GHG mitigation cost curve for all scenarios

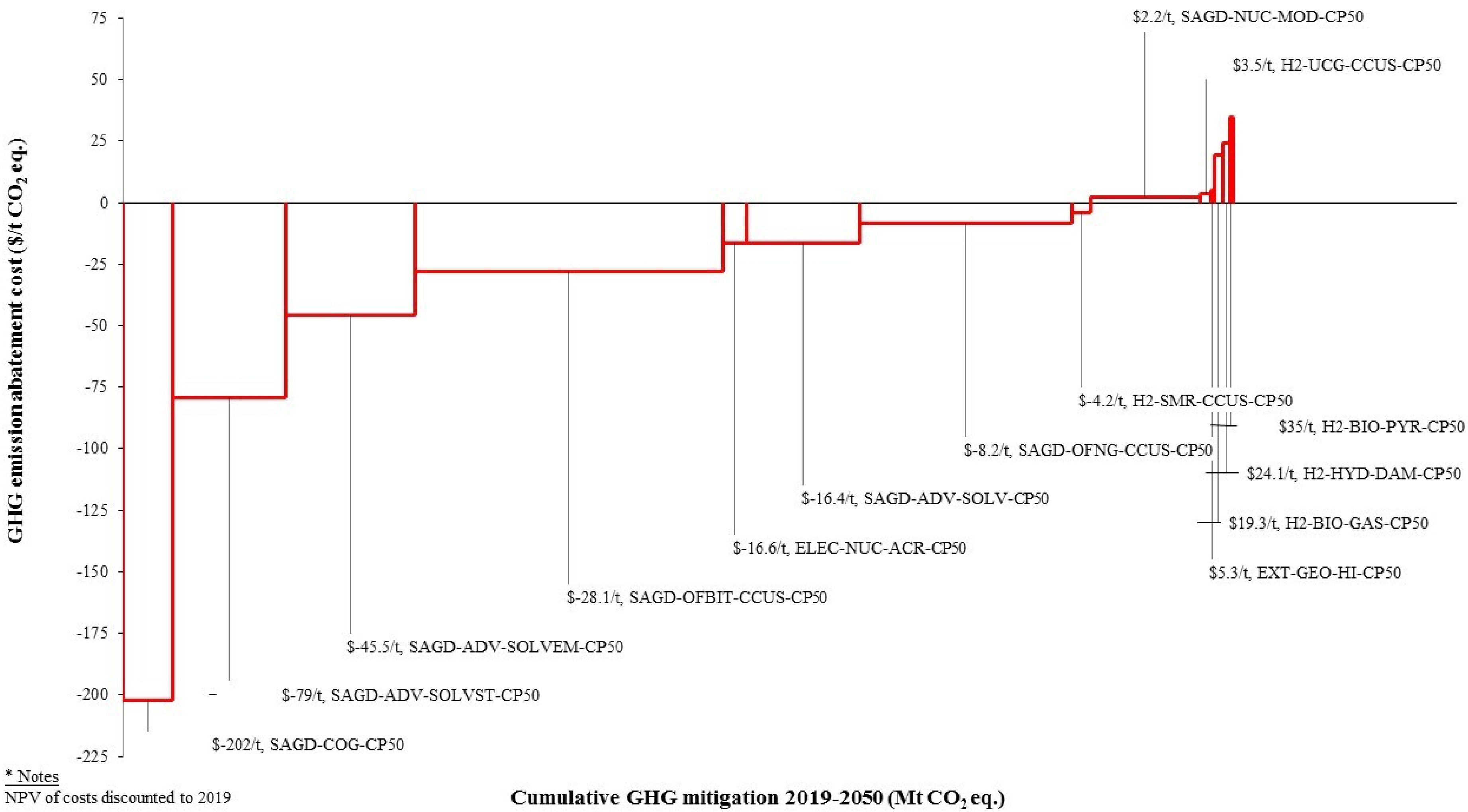


Figure 8-3: GHG mitigation cost curves for scenarios with the best cost performance that can be deployed simultaneously

8.2 Recommendations for future work

Research that could expand upon the research conducted here includes performing more techno-economic studies on oil sands technologies so they can be modelled in a framework such as this, understanding the wider environmental effects of the technologies considered here, and expanding this study to other sectors with high GHG emissions. The availability of techno-economic data for technologies that could be used in oil sands processes was a key limiting factor when developing technology scenarios. Several technologies were identified in each technology class that would be expected to reduce GHG emissions in oil sands processes if used but did not have enough economic or performance data to reliably be included in this study. Examples include nuclear thermochemical hydrogen production, chemical looping combustion processes for carbon capture and storage, and newer advanced in situ extraction techniques such as surfactant use. These and others identified in the chapters above would benefit from further analysis and they could be incorporated into this work.

The method itself could be improved through comparative studies with other modelling methods and by taking wider environmental factors into account. The bottom-up energy modelling used in this study would benefit from comparisons to similar studies using top-down models to identify and understand any differences in expected results. The model in this study is also impacted by the bitumen production forecasts used, and there are many ways of forecasting expected production. The results from this research developed using government forecasts would benefit from comparison to other methods and economic forecasts. GHG emissions are not the only environmental consideration when understanding the benefits of using one technology over another, and this study could be expanded to include considerations such as water use as well. The developer of the LEAP software also has the Water Evaluation and Planning (WEAP) software, and the results from LEAP scenarios can be evaluated with WEAP to understand the impact on the freshwater system as well as GHG emissions. This would involve developing water intensities for each technology option similar to how energy intensities are used in this study, then forecasting water usage in each scenario and would result in combined GHG abatement and freshwater demand abatement/increase for each technology. Expanding the scenarios considered in this study to include water impacts would give a better understanding of the environmental impacts of the technologies considered. Finally, other industry sectors would benefit from the approach developed in this study to incorporate market penetration modelling with energy accounting. This method allows for the projection of the GHG abatement and marginal costs of technologies in feasible scenarios and would be useful to stakeholders in other industries that are working to reduce GHG emissions.

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Appendix A – NEB forecast data

Table 1: Modeled production forecast and natural gas price input data from NEB report to 2040 [1] and extrapolated to 2050

	NEB 2018 Forecast (kbpd)				NEB 2018 Forecast (2018 $CAD)
Year	**Alberta total oil production**	**Mined bitumen**	**In situ bitumen**	**Upgraded bitumen**	**Natural gas price**
2009	2081.9	825.2	663.6	722.5	
2010	2193.0	856.9	752.4	702.6	
2011	2349.4	892.5	847.4	810.2	
2012	2594.9	932.3	989.9	817.1	
2013	2789.5	976.0	1106.1	835.1	
2014	2964.2	960.2	1262.7	842.5	
2015	3237.1	1161.4	1361.9	850.4	
2016	3214.9	1150.0	1398.3	931.8	
2017	3531.5	1275.7	1546.8	1050.7	
2018	3865.2	1476.8	1645.7	1079.1	3.22
2019	4084.3	1598.6	1721.9	1138.0	3.25
2020	4193.2	1632.9	1784.3	1162.9	3.33
2021	4242.2	1641.8	1813.5	1171.9	3.45
2022	4287.8	1646.8	1840.9	1187.9	3.62
2023	4381.2	1646.8	1918.9	1195.5	3.8
2024	4501.3	1646.8	2020.8	1218.2	3.99
2025	4614.4	1646.8	2110.9	1235.2	4.18
2026	4715.6	1646.8	2186.4	1235.4	4.38
2027	4801.3	1646.8	2248.2	1235.4	4.41
2028	4860.2	1646.8	2285.2	1243.0	4.44
2029	4950.1	1646.8	2354.6	1262.9	4.47
2030	5067.5	1646.8	2449.7	1275.2	4.5
2031	5189.9	1646.8	2545.9	1275.4	4.54
2032	5284.3	1646.8	2612.6	1275.4	4.57
2033	5364.8	1646.8	2664.1	1275.4	4.6
2034	5419.4	1646.8	2688.6	1275.4	4.64
2035	5478.5	1646.8	2717.2	1275.4	4.67
2036	5528.9	1646.8	2736.8	1275.4	4.7
2037	5583.6	1646.8	2760.7	1275.4	4.74
2038	5637.8	1646.8	2783.8	1275.4	4.77
2039	5687.6	1646.8	2802.0	1275.4	4.8
2040	5737.9	1646.8	2820.4	1275.4	4.84
2041	5823.0	1646.8	2847.7	1275.4	5.03
2042	5908.1	1646.8	2870.1	1275.4	5.09

2043	5993.3	1646.8	2892.6	1275.4	5.16
2044	6078.4	1646.8	2915.0	1275.4	5.22
2045	6163.5	1646.8	2937.5	1275.4	5.29
2046	6248.6	1646.8	2959.9	1275.4	5.35
2047	6333.7	1646.8	2982.4	1275.4	5.42
2048	6418.9	1646.8	3004.8	1275.4	5.48
2049	6504.0	1646.8	3027.2	1275.4	5.54
2050	6589.1	1646.8	3049.7	1275.4	5.6

Appendix B – Equation 4-1 input values

Table 1: Equation 4-1 input values

Technology	CC	OC	ECC*	EC	Units	Lifetime (years)	Reference
Reference - Upgrading	0.81	0.34	0.012	$0.15*P_{NG}$	$/kg H_2	20	Costs - [39] Emissions - [28]
WIN-H2-TURB	2.99	11.4	0.006	0	$/kg H_2	20	[31]
WIN-H2-FARM	0.18	8.25	0.002	0	$/kg H_2	20	[32]
HYD-H2-DAM	0.14	2.29	0.002	0	$/kg H_2	40	[30]
BIO-H2-GAS	0.44	1.62	0.002	0.49	$/kg H_2	20	[28]
BIO-H2-PYR	0.45	1.82	0.001	0.49	$/kg H_2	20	[29]
Reference - CSS	1.29	0.1	0.063	$1.43*P_{NG}$	$/bbl	20	[33]
SOL-CSS	13.99	5.82	0	0	$/bbl	20	[33]
Reference - SAGD	1.14	0.09	0.056	$1.30*P_{NG}$	$/bbl	20	[27]
NUC-SAGD-MOD	5.34	0.86	0	1.16	$/bbl	20	[27]
Reference - Surface mining extraction	-	-	0.041	$0.34*P_{NG}$	$/bbl	20	[26]
GEO-EXT-LOW	6.56	3.95	0	0	$/bbl	30	[26]
GEO-EXT-HI	1.61	0.99	0	0	$/bbl	30	[26]
Reference - Electricity	19.31	15.22	0.44	$7.72*P_{NG}$	$/MWh	20	[27]
NUC-ELEC-ACR	44.24	18.04	0	5.45	$/MWh	30	[27]
HYD-ELEC-DAM	22.59	58.41	0	0	$/MWh	70	[86]

Appendix C – Alberta electricity price forecast

Table 1: Alberta electricity price forecasts

	AB Grid Prices ($/MWh) [148]*	
Year	**AB Grid Pool Price**	**AB Grid Transmission Price**
2018	45.00	35.00
2019	44.69	35.31
2020	54.38	35.63
2021	64.06	35.94
2022	78.75	36.25
2023	83.43	36.56
2024	93.13	36.88
2025	92.81	37.19
2026	102.50	37.50
2027	97.18	37.81
2028	101.80	38.13
2029	101.56	38.44
2030	101.25	38.75
2031	103.43	39.06
2032	105.62	39.38
2033	107.81	39.69
2034	110.00	40.00
2035	112.19	40.31
2036	114.38	40.63
2037	116.56	40.94
2038	118.75	41.25
2039	120.94	41.56
2040	123.13	41.88
2041	125.31	42.19
2042	127.50	42.50
2043	129.69	42.81

Appendix D – Cogeneration technology sensitivity results

Table 1: Cost variance parameter sensitivity analysis results

CP	Scenario	6	7	8	9	10
No CP	COG-MIN-CP0	6.0%	6.1%	6.2%	6.3%	6.5%
	COG-SAGD-CP0	20.9%	21.0%	21.2%	21.3%	21.5%
	COG-UPG-CP0	8.7%	8.8%	9.0%	9.1%	9.3%
CP30	COG-MIN-CP30	6.1%	6.3%	6.4%	6.6%	6.7%
	COG-SAGD-CP30	21.5%	21.8%	22.0%	22.3%	22.5%
	COG-UPG-CP30	8.8%	8.9%	9.0%	9.2%	9.3%
CP50	COG-MIN-CP50	6.1%	6.3%	6.4%	6.6%	6.7%
	COG-SAGD-CP50	21.6%	21.9%	22.1%	22.4%	22.6%
	COG-UPG-CP50	8.8%	8.9%	9.1%	9.2%	9.4%

Table 2: IRR sensitivity analysis results

		5.00%			7.50%			10.00%			12.50%			15.00%		
CP	Scenario	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t
No CP	COG-MIN-CP0	8.8%	1.90	-3865.83	7.9%	2.13	-2252.08	6.6%	1.87	-1291.09	5.1%	1.73	-323.63	3.6%	1.48	385.70
	COG-SAGD-CP0	34.4%	61.28	-517.08	29.2%	52.98	-348.98	21.8%	36.21	-201.08	14.0%	19.24	-12.60	8.0%	7.43	347.44
	COG-UPG-CP0	14.0%	1.26	-3023.32	12.0%	1.19	-1705.53	9.1%	1.09	-474.86	5.9%	0.98	367.78	3.4%	0.88	703.06
CP30	COG-MIN-CP30	8.9%	1.92	-3955.17	8.0%	1.74	-2886.86	6.7%	1.90	-1364.80	5.3%	1.60	-420.60	3.8%	1.52	354.48
	COG-SAGD-CP30	34.5%	61.48	-519.14	29.3%	52.40	-356.86	22.0%	36.79	-201.51	14.3%	19.63	-13.77	8.2%	7.84	336.15
	COG-UPG-CP30	14.0%	1.26	-3077.10	12.1%	1.19	-1756.99	9.2%	1.09	-517.19	6.0%	0.98	344.07	3.5%	0.89	699.69
CP50	COG-MIN-CP50	9.0%	1.92	-3990.12	8.0%	1.74	-2921.55	6.7%	1.90	-1391.46	5.3%	1.60	-445.11	3.8%	1.52	336.12
	COG-SAGD-CP50	34.6%	61.50	-520.15	29.4%	52.48	-357.69	22.1%	37.00	-202.05	14.4%	19.89	-14.87	8.3%	7.99	331.85
	COG-UPG-CP50	14.0%	1.26	-3047.29	12.1%	1.19	-1730.26	9.2%	1.10	-495.18	6.0%	0.98	361.19	3.5%	0.89	712.73

Table 3: % change to natural gas price sensitivity analysis results

		-20.00%			-10.00%			0.00%			10.00%			20.00%		
CP	Scenario	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t
No CP	COG-MIN-CP0	6.6%	1.88	-1330.69	6.6%	1.87	-1310.86	6.6%	1.87	-1291.09	6.5%	1.86	-1271.39	6.5%	1.85	-1251.74
	COG-SAGD-CP0	22.9%	39.09	-224.12	22.3%	37.64	-212.70	21.8%	36.21	-201.08	21.2%	34.85	-189.07	20.7%	34.25	-173.00
	COG-UPG-CP0	9.2%	1.09	-486.65	9.2%	1.09	-483.98	9.1%	1.09	-474.86	9.1%	1.09	-478.72	9.1%	1.09	-476.13
CP30	COG-MIN-CP30	6.8%	1.92	-1404.82	6.8%	1.91	-1384.78	6.7%	1.90	-1364.80	6.7%	1.90	-1344.88	6.7%	1.89	-1325.01
	COG-SAGD-CP30	23.2%	39.68	-224.48	22.6%	38.21	-213.15	22.0%	36.79	-201.51	21.5%	35.45	-189.39	20.9%	34.10	-177.21
	COG-UPG-CP30	9.3%	1.10	-529.27	9.2%	1.10	-526.50	9.2%	1.09	-517.19	9.2%	1.09	-521.03	9.2%	1.09	-518.34
CP50	COG-MIN-CP50	6.8%	1.92	-1431.56	6.8%	1.91	-1411.48	6.7%	1.90	-1391.46	6.7%	1.90	-1371.50	6.7%	1.89	-1351.59
	COG-SAGD-CP50	23.3%	39.88	-225.04	22.7%	38.42	-213.70	22.1%	37.00	-202.05	21.6%	35.62	-190.18	21.0%	34.32	-177.78
	COG-UPG-CP50	9.3%	1.10	-507.16	9.3%	1.10	-504.42	9.2%	1.10	-495.18	9.2%	1.09	-499.02	9.2%	1.09	-496.36

Table 4: % change to forecasted market growth sensitivity analysis results

		-20.00%			-10.00%			0.00%			10.00%			20.00%		
CP	Scenario	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t
No CP	COG-MIN-CP0	6.6%	1.60	-1206.51	6.6%	1.72	-1256.69	6.6%	1.87	-1291.09	6.6%	1.99	-1329.06	6.6%	2.13	-1359.84
	COG-SAGD-CP0	21.8%	26.07	-223.41	21.8%	31.46	-208.29	21.8%	36.21	-201.08	21.8%	41.77	-191.75	21.8%	46.71	-187.05
	COG-UPG-CP0	9.1%	1.02	-410.57	9.1%	1.06	-445.71	9.1%	1.09	-474.86	9.1%	1.12	-515.02	9.1%	1.15	-546.91
CP30	COG-MIN-CP30	6.7%	1.63	-1277.08	6.7%	1.76	-1329.15	6.7%	1.90	-1364.80	6.7%	2.04	-1403.15	6.7%	2.15	-1776.68
	COG-SAGD-CP30	22.0%	26.56	-223.34	22.0%	32.01	-208.49	22.0%	36.79	-201.51	22.0%	42.40	-192.36	22.0%	47.38	-187.78
	COG-UPG-CP30	9.2%	1.03	-444.06	9.2%	1.06	-485.06	9.2%	1.09	-517.19	9.2%	1.13	-560.31	9.2%	1.16	-594.91
CP50	COG-MIN-CP50	6.7%	1.63	-1302.03	6.7%	1.76	-1355.12	6.7%	1.90	-1391.46	6.7%	2.04	-1430.56	6.7%	2.15	-1811.38
	COG-SAGD-CP50	22.1%	26.73	-223.80	22.1%	32.15	-209.30	22.1%	37.00	-202.05	22.1%	42.62	-192.97	22.1%	46.93	-191.19
	COG-UPG-CP50	9.2%	1.03	-425.40	9.2%	1.06	-464.66	9.2%	1.10	-495.18	9.2%	1.13	-536.71	9.2%	1.16	-569.84

Table 5: % change to cogeneration plant efficiency sensitivity analysis results

		-10.00%			-5.00%			0.00%			5.00%			10.00%		
CP	Scenario	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t	Pen	Mitigation	$/t
No CP	COG-MIN-CP0	6.6%	0.51	-4737.22	6.6%	1.25	-1930.62	6.6%	1.87	-1291.09	6.5%	2.39	-1007.83	6.5%	2.84	-847.99
	COG-SAGD-CP0	22.9%	3.00	-2427.88	22.3%	21.09	-345.29	21.8%	36.21	-201.08	21.2%	49.04	-148.47	20.7%	60.07	-121.22
	COG-UPG-CP0	9.2%	0.31	-1711.23	9.2%	0.74	-715.50	9.1%	1.09	-474.86	9.1%	1.40	-376.72	9.1%	1.66	-317.45
CP30	COG-MIN-CP30	6.8%	0.52	-4971.23	6.8%	1.27	-2038.06	6.7%	1.90	-1364.80	6.7%	2.44	-1066.01	6.7%	2.90	-897.24
	COG-SAGD-CP30	23.2%	3.24	-2286.28	22.6%	21.52	-344.59	22.0%	36.79	-201.51	21.5%	49.76	-149.01	20.9%	60.89	-121.76
	COG-UPG-CP30	9.3%	0.31	-1861.91	9.2%	0.74	-778.54	9.2%	1.09	-517.19	9.2%	1.40	-409.92	9.2%	1.66	-345.42
CP50	COG-MIN-CP50	6.8%	0.52	-5068.33	6.8%	1.27	-2077.87	6.7%	1.90	-1391.46	6.7%	2.44	-1086.83	6.7%	2.90	-914.77
	COG-SAGD-CP50	23.3%	3.33	-2248.07	22.7%	21.67	-345.05	22.1%	37.00	-202.05	21.6%	50.02	-149.49	21.0%	61.19	-122.18
	COG-UPG-CP50	9.3%	0.31	-1784.01	9.3%	0.74	-745.81	9.2%	1.10	-495.18	9.2%	1.40	-392.66	9.2%	1.66	-330.87