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

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ABSTRACT

The purpose of this research is to evaluate the greenhouse gas reduction potential and associated costs of integrating renewable energy technologies into Canada's oil sands . There is very limited analysis in the literature focused on the integration of renewable technology options in oil sands processes. This research addresses the gap by developing a novel framework that applies market penetration and bottom-up energy modeling techniques. A total of 27 long-term scenarios across oil sands extraction, upgrading, and electricity generation were investigated. The results show that up to 84 million tonnes of greenhouse gas emissions abatement (2.3% of oil sands GHG emissions) at a marginal greenhouse gas abatement cost of \$1.3/tCO$_2$e is available under a \$30/tonne carbon incentive. Scenarios with no carbon incentive resulted in 69 million tonnes less greenhouse gas emissions abatement and a marginal greenhouse gas abatement cost increase of \$36/tCO$_2$e. Nuclear-based scenarios mitigated the largest amount of greenhouse gases and had the lowest marginal abatement costs. Geothermal energy, bio-energy, and hydropower were cost effective in certain scenarios but had limited greenhouse gas emission reduction potential. Wind and solar technologies failed to displace existing processes in the scenarios considered. The results from this study may be of value to government policy makers and industry representatives aiming to reduce greenhouse gases.

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 (IEA, 2019) 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 to 2040 (IEA, 2018). Global greenhouse gas (GHG) emission are also a growing environmental concern, most recently acknowledged by many countries in the Paris Agreement (U.N., 2015). Analysis of global GHG emissions shows that at least 65% are from fossil fuel consumption and industrial processes (IPCC, 2014). 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 (Lazzaroni et al., 2016). 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 (NRC, 2018b) and was a 56% increase from 2010. It is projected to grow to 4.4 million bbl/day by 2035 (CER, 2018). The oil sands industry contributed CAD\$82.6 billion to the Canadian economy, or roughly 5% of the GDP, in 2016 (CERI, 2017).

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 (Masliyah et al., 2011). Crude bitumen from oil sands is produced through surface mining or in situ techniques. Surface mining is

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Nomenclature

Abbreviations and acronyms

AER	Alberta Energy Regulator
bbl	Barrel
Bpd	Barrels per day
CAD	Canadian dollar
CCS	Carbon capture and storage
CCIR	Carbon competitiveness incentive regulation
CERI	Canadian Energy Research Institute
CSS	Cyclic steam stimulation
dilbit	Diluted bitumen
GJ	Gigajoule
IRR	Internal rate of return
LEAP	Long-range Energy Alternatives Planning
MJ	Megajoule
MT	Million tonnes
NEB	National Energy Board
PBMR	Pebble bed modular reactor
PV	Photovoltaic
SAGD	Steam-assisted gravity drainage
SCO	Synthetic crude oil
SMR	Steam methane reforming
tCO_2e	Tonne of carbon dioxide equivalent

Variables

CC	Capital cost
EC	Energy cost
ECC	Emitted carbon cost
LCC	Life cycle cost
n	Technology lifetime
MS	Market share
OC	Operation and maintenance costs
SC	Scenario cost
SE	Scenario emissions (metric tonnes)

Parameters

i	Interest rate
v	Cost variance parameter
y	Year

Sets

REF	Reference scenario
j	Technology
x	Alternative scenario

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 (Jacob et al., 2013). Various techniques are used for in situ extraction, the most common being steam-assisted gravity drainage (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. 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). 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. Steam production is responsible for the largest portion of industry emissions – 50% of industry-wide carbon emissions. Because of the growth of in situ methods, GHG emissions from oil sands have increased and will continue to grow.

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 (NRC, 2018b). Governments at federal and provincial levels in Canada have made GHG reduction a priority, with the oil sands identified as a key sector (GOC, 2016). The Alberta government has capped oil sands emissions at 100 MT/year (GOA, 2018a). Despite these efforts, projections suggest that GHG emissions will continue to increase (Katta et al., 2019). Hence, there is a need to develop ways for reduction of GHG emissions from oil sands sector. Integration of renewable and low-carbon energy could lead to cost-effective GHG reductions.

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 (Ghandehariun and Kumar, 2016) or assessing the cost of implementation (Kumar et al., 2017). A number of techno-economic assessments were performed for a wide range of renewable energy applications. Hofmann et al. (2014) found that GHG emissions can be significantly reduced through use of geothermal energy. Pathak et al. (2014) found that it could be economical to heat water through geothermal energy in the oil sands area. Other literature on integrating renewables into the oil sands includes assessing nuclear energy (Bersak and Kadak, 2007), solar energy for steam production (Kraemer et al., 2009), electrolysis of wind energy at the small scale (Olateju and Kumar, 2011) and large scale (Olateju et al., 2014), electrolysis of hydropower (Olateju and Kumar, 2016), and hydrogen from biomass gasification (Sarkar and Kumar, 2009) and fast pyrolysis (Sarkar and Kumar, 2010b). 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 a selected renewable energy technologies as options of GHG mitigation for oil sands using optimization models (Elsholkami et al., 2016). 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 also limited focus in the literature on the assessment of impacts of carbon incentive policies on the use of low emission technologies for oil sands. 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 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 (Nyboer, 1997). 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 (Train, 1985), but this approach has yet to be used to evaluate long-term renewable technology adoption in the oil sands. A bottom-up energy accounting model, such as those constructed using the Long-range Energy Alternatives (LEAP) system (Heaps, 2016), 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 (Heaps, 2016). 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 each 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 (IPCC, 2014), 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 (Katta et al., 2019). Energy intensities for each technology were developed using various publications and industry reports.

In light of the studies presented above, the knowledge gap that 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. Previous work has focused on evaluation of single measures without long-term market adoption considerations. This research work makes four unique contributions:

- A novel framework for renewable energy integration into unconventional oil extraction 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;
- Wide-scale sector-wide deployment of multiple renewable energy scenarios are evaluated and compared;
- 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 to 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 to GHG mitigation cost curves for integration or renewable energy technologies in oil sands sector.

2. Methods

2.1. Framework

Fig. 1 shows the overall study framework, that is, the key input data, the interaction between the models, including the market penetration model and the bottom-up energy accounting model (LEAP), and the outputs. The purpose of the framework is to provide a way to assess scenarios where long-term feasible renewable or low carbon energy supply options are adopted as an alternative to conventional fossil-based technologies in the oil sands. To accomplish this, renewable and low-carbon scenarios were formulated based on technology data sets that were created out of a literature review on the possible technology options; for the renewable and low-carbon technology options that had sufficient economic and technical data, scenarios were formulated around competition of these technologies with the fossil-based reference technology. An excel-based market penetration model is used to project annual usage rates of competing technologies to year 2050 based on their annualized costs and an inverse power function that follows technology adoptions patterns. The market penetration model is integrated with a bottom-up energy accounting model that is then used to calculate GHG emission levels and marginal abatement costs of each scenario being considered. The key input data to the models include macro-economic and technology data sets. The macro-economic data is made up of projections of industry production levels, policies that have a financial impact on the industry, fuel price projections for fuels used in the industry, and values used in cost analysis such as the discount rate. Technology data sets include cost, energy, and emission information.

Each section of the framework is explained in detail subsequent subsections. The next section (2.2) discusses the scenario development. Section 2.3 presents the market penetration model, Section 2.4 introduces the LEAP-Oil Sands model and method of cost-benefit analysis, and Section 2.5 discusses the parameters chosen for sensitivity analysis.

2.2. Scenario development

2.2.1. Review of renewable and low carbon energy technology options

Studies on renewable energy technologies applicable to the oil sands are reviewed here in order to inform the scenario development and reference technologies. Technologies are categorized as biomass feedstock, nuclear, hydro, geothermal, solar, and wind. In

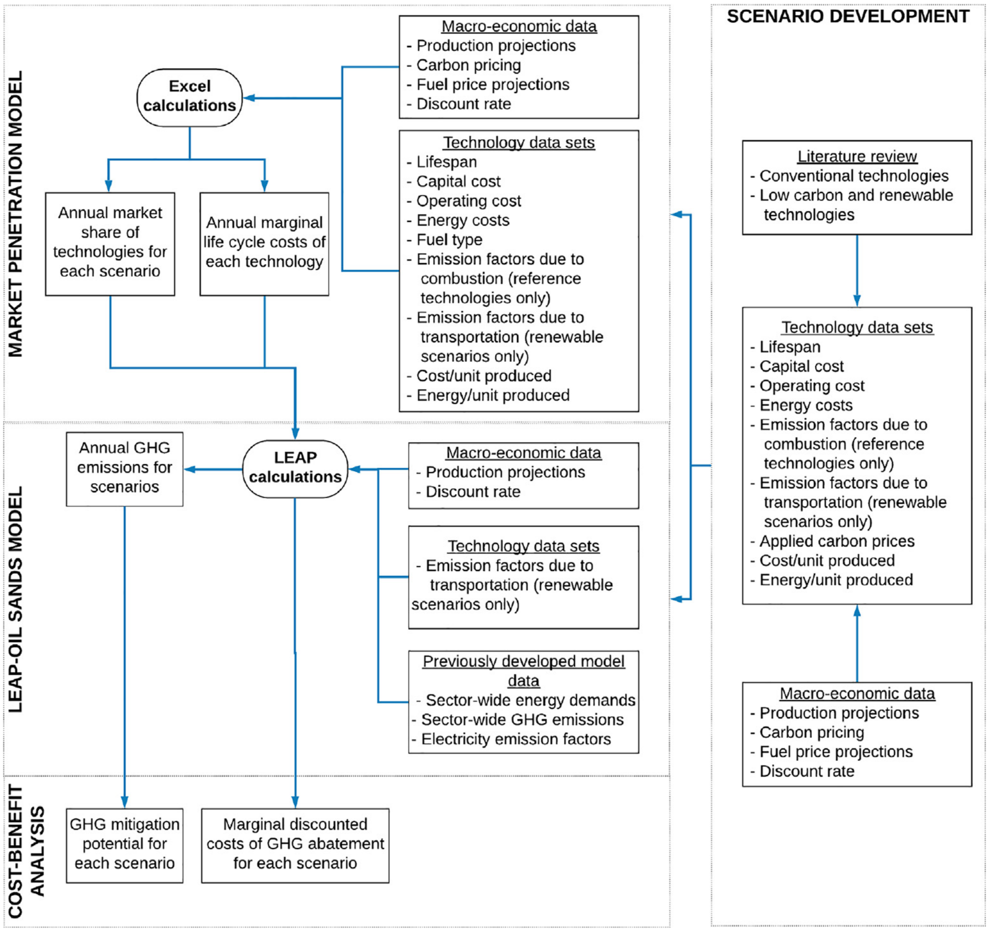


Fig. 1. Developed analysis framework for assessment of oil sands GHG emission mitigation and marginal abatement costs.

addition to the review, the technologies' functions are explained and the level of data currently available is discussed.

2.2.1.1. 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 relatively short time spans and are 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 (Johnston and van Kooten, 2015), and the Alberta government is actively encouraging the development of bioenergy through the Bioenergy Producer Program (GOA, 2017b). 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 (Sarkar and Kumar, 2009). 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 (Sarkar and Kumar, 2010a). 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 (Sarkar and Kumar, 2010b). 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 (Lónyi et al., 2013) 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 (Sarkar and Kumar, 2009) and the technical challenges of purifying and storing produced hydrogen (Levin and Chahine, 2010).

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 (Kumar et al., 2017). 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 (NREL, 2000). 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 (Levin and Chahine, 2010).

2.2.1.2. 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 (Adamantiades and Kessides, 2009). 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 (Locatelli et al., 2014). The heat, electricity, and hydrogen requirements of oil sands operations make the industry a good candidate for these newer generation systems (Betancourt-Torcat et al., 2012). Specifically, plants built for combined steam and electricity production based on market conditions offer significant advantages in the oil sands industry (Locatelli et al., 2017). 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 (Canadian Small Modular Reactor Roadmap Steering Committee, 2018).

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 (Becerra et al., 2005). 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 (Bersak and Kadak, 2007). They also found that an ACR-700 reactor could competitively supply electricity over the Alberta grid or local cogeneration options (Bersak and Kadak, 2007).

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 (Naterer et al., 2009). Combining electricity production and hydrogen production through load following has also been shown to have potential applications (Wang and Naterer, 2010). 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 (Locatelli et al., 2014). 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.

2.2.1.3. Hydro

2.2.1.3. 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 (NRC, 2018a). 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 (CERI, 2016).

Studies have considered the role of hydropower in oil sands processes, such as using hydro for hydrogen production (Olateju and Kumar, 2016) and to provide low-carbon electricity (CERI, 2016). 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 (Olateju and Kumar, 2016). 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 (CERI, 2016). 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 (Davis, 2017). 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 (Okot, 2013). Run-of-river hydropower is often an economical solution in rural areas long distances from power generation centers (Paish, 2002). The oil sands meet this criteria, and locations on the Athabasca River near oil sands operations have been identified recently as potentially viable (JWN, 2018); 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.

2.2.1.4. Geothermal. The average temperature gradient in the oil sands area is around 21 °C/km, and at the depths where use temperatures (~5 km) are achieved, the formations are characterized as dry granite, which is challenging to drill through and not generally porous (Pathak et al., 2014). 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 (Majorowicz, 2013). 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 (Hofmann et al., 2014). 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 (Pathak et al., 2014).

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.

2.2.1.5. 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 (Sandler et al., 2014). 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. Techno-economic studies on the impact of solar photovoltaic (PV) electricity was not found in the published literature. 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 (Pregger et al., 2009) and could be cost competitive with SMR under certain conditions.

2.2.1.6. 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 (Ghandehariun and Kumar, 2016).

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 (Olateju and Kumar, 2011). 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 (Olateju et al., 2014). 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.

2.2.2. Scenario formulation

Table 1 summarizes the literature review from the previous section. The technologies with sufficient techno-economic data to develop scenarios are identified in the table. The groupings of these technologies include hydrogen production technologies for bitumen upgrading, steam and heat generation technologies for in situ, heat generation technology for surface mining, and electricity generation technology for the general oil sands area. The data for these particular technologies was used to formulate the oil sands renewable and low-carbon technology scenarios going forward.

Developing scenarios involved breaking down bitumen production from the oil sands into major processes and incorporating the technology options with enough techno-economic data found in the previous section. Fig. 2 highlights the major oil sands processes considered in this study and the screened technology options. Surface mining and in situ extraction methods produce crude bitumen that is either diluted and exported from the plant or sent for upgrading into SCO. Renewable and low-carbon technologies with enough economic and technical data for scenario development are listed in the green boxes in the figure, along with the conventional fossil fuel-based technology that would be replaced if the renewable or low-carbon alternatives were adopted.

Table 2 contains the data sets for each alternative technology scenarios. The table shows the scenario names, applicable subsectors, reference scenario technologies that will be replaced in the alternative scenario. Scenario are named by subsector-energy product-technology. Capital costs, operating costs, energy costs, lifetime, and emission factors (transportation emissions for renewable technology scenarios, combustion emissions for reference technologies) are also given. Data sources for costs and the emission factors are listed in Table 2 also, and further details of these can be found in Section 2.2.1. Where applicable, the annualized capital costs were taken or calculated from the sources using Equation (1) using an internal rate of return (IRR) of 10% for the interest rate. All costs were converted to 2019 CAD. Fig. 3 shows the approximate geographical locations of technologies when products require transportation and includes details on how the products are transported. Costs and emissions associated with transportation are included in the values of Table 2.

$$\mathrm{ACC_j} = \left(\mathrm{CC_j} \times \frac{\mathrm{i}}{1-(1+\mathrm{i})^{-\mathrm{n}}}\right) \tag{1}$$

Three different carbon incentive policies were also considered for each scenario. 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 $\$30/\mathrm{tCO_2e}$ from 2018 to 2050, corresponding to a carbon incentive at this level (AEP, 2017). The third, "CP50," uses a real price of $\$30/\mathrm{tCO_2e}$ until 2021 and an incentive of $\$50/\mathrm{tCO_2e}$ from 2022 to 2050, matching the cost of carbon mandated in the federal government's Pan-Canadian Framework on Clean Growth and Climate Change (GOC, 2016). The carbon incentive amounts are fully applied to annual emissions in the analysis. Sensitivity analysis was performed to determine the impact of a wider range of values. Scenario names presented in the results 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."

2.3. Market penetration model

The market penetration model uses a function developed in an earlier study for the energy industry to model technology choice behavior using annualized life cycle costs (Jaccard et al., 2003). Equation (2) simulates technology competition and is taken from literature (Nyboer, 1997).

$$\mathrm{MS_{j,y}} = \frac{\mathrm{LCC_{j,y}^{-v}}}{\sum_{\mathrm{j=1}}^{\mathrm{k}}\mathrm{LCC_{j,y}^{-v}}} \tag{2}$$

$\mathrm{MS_j}$ is the market share for technology j in the year, y, 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 (Nyboer, 1997), corresponding to a 10% price differential producing a 32% difference in market share. Lower values of v have been observed in the literature and so a wide range is tested in the sensitivity analysis. The annualized life cycle costs (*LCC*) of each technology includes annualized capital costs, operating costs, carbon costs, and energy costs and is shown in Equation (3), modified from literature (Nyboer, 1997).

Table 1
Summary of oil sands technology options.

Renewable/low-carbon energy technology	Integration options	Sufficient techno-economic data available for scenario development?	Key technoeconomic results	Comments/sources
Biomass gasification	Bitumen upgrading	Yes	\$2.19–2.31/kg of H_2	Hydrogen production to replace SMR plants (Sarkar and Kumar, 2009)
Biomass pyrolysis	Bitumen upgrading	Yes	\$2.40–4.55/kg of H_2	Hydrogen production to replace SMR plants (Sarkar and Kumar, 2010b)
Biomass hydrothermal liquefaction	Dilbit production	No	–	Production of diluent to replace use of fossil-based light hydrocarbons (Kumar et al., 2017)
Biomass dark fermentation	Bitumen upgrading	No	–	Hydrogen production to replace SMR plants (Levin and Chahine, 2010)
Biomass catalyzed oxygenation	Bitumen upgrading	No	–	Hydrogen production to replace SMR plants (Levin and Chahine, 2010)
Nuclear ACR-700 reactor	Electricity	Yes	Competitive with natural gas at \$10/MMBtu	Electricity generation for general industry use (Bersak and Kadak, 2007)
Nuclear small modular reactor	In situ	Yes	Competitive with natural gas at \$6.50/MMBtu	Steam production for SAGD facilities (Bersak and Kadak, 2007)
Nuclear thermochemical hydrogen production	Bitumen upgrading	No	–	Hydrogen production to replace SMR plants (Naterer et al., 2009)
Hydro energy electrolysis	Bitumen upgrading	Yes	\$1.87–2.60/kg of H_2	Hydrogen production to replace SMR plants (Olateju and Kumar, 2016)
Hydro dam	Electricity	Yes	GHG mitigation cost of \$73/tCO_2e	Electricity generation for general industry use (CERI, 2016)
Run-of-river hydro	Electricity	No	–	Electricity generation for general industry use (Okot, 2013)
Geothermal energy	Surface mining	Yes	\$0.06/kWh thermal cost of heat	Further understanding of geothermal gradients in oil sands areas required (Majorowicz, 2013) (Pathak et al., 2014)
Solar heat	In situ – heat	Yes	ROI range of 14–20 years	Steam production for CSS facilities (Kraemer et al., 2009)
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 (Olateju and Kumar, 2011) (Olateju et al., 2016)

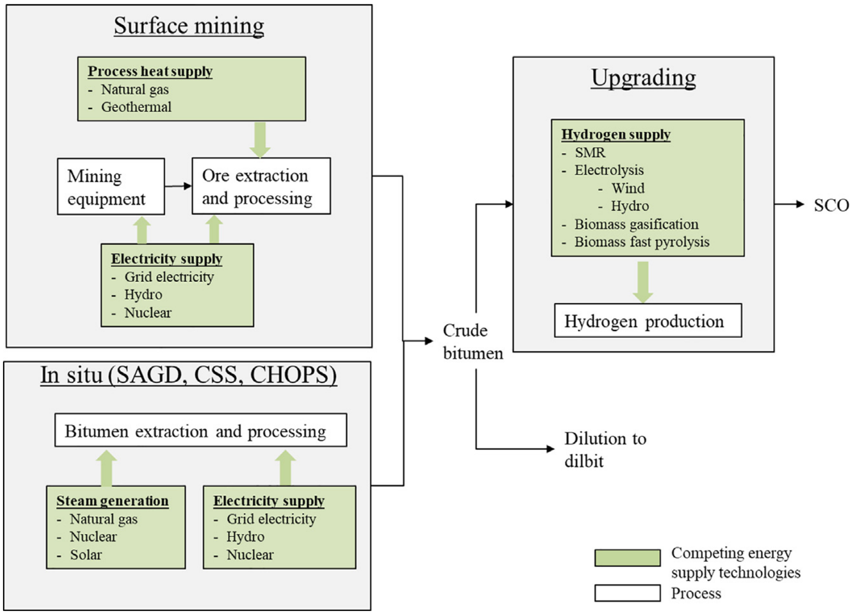


Fig. 2. Developed framework for integration of renewable technologies applicable to oil sands operations.

$$LCC_{j,y} = ACC_j + OC_j + ECC_{j,y} + EC_{j,y} \tag{3}$$

$LCC_{j,y}$ is the annualized lifetime cost of technology j in year y, ACC_j is the annualized capital cost, OC_j is the annual operation and maintenance costs, $ECC_{j,y}$ is the annual emitted carbon cost (if a carbon incentive policy is in place), and $EC_{j,y}$ is the annual energy or fuel cost. The scenarios were evaluated for the years 2019–2050, from the time of this study to the end year of Canada's Mid-Century Long-Term Low-GHG Development Strategy (ECCC, 2016) to align with federal clean development strategies.

Table 3 outlines the resulting LCC equations, which are applied to each scenario in each year of the analysis. Equation (2) is applied considering all of the technologies across scenarios within a sub-sector. For example, the upgrading sector has 6 technologies competing, the CSS sector has 2 technologies competing, etc.

The annual market share of new production allocated to each technology is determined with Equation (2) and multiplied by the amount of new product in a given year to give the allocated production to each technology. Annual new product projections,

Table 2
Technology cost data sets for scenarios.

Sector: Energy product Scenario name	Technology techno-economic data								
	Technology	Fuel source	Capital cost (CC)	Operating cost (OC)	Energy cost (EC)	Cost/ production unit	Emission factor (EF) [kg CO_2/unit production]	Lifetime (years)	Source
Upgrading: Hydrogen supply									
Reference	Steam methane reforming (SMR)	Natural gas	0.93	0.39	0.17[a]P_{NG}	\$/kg H_2	11.9	20	Costs - (Olateju and Kumar, 2013) Emissions - (Sarkar and Kumar, 2009)
UPG-H2-WIN-TURB	Wind electrolysis - Single turbines	Wind	3.44	13.11	–	\$/kg H_2	6.4	20	Olateju and Kumar (2011)
UPG-H2-WIN-FARM	Wind electrolysis - Wind farm	Wind	0.21	9.49	–	\$/kg H_2	1.6	20	Olateju et al. (2014)
UPG-H2-HYD-DAM	Hydro electrolysis - Hydro dam	Hydro	0.15	2.43	–	\$/kg H_2	1.6	40	Olateju and Kumar (2016)
UPG-H2-BIO-GAS	Biomass gasification	Whole tree	0.51	1.88	0.57	\$/kg H_2	1.2	20	Sarkar and Kumar (2009)
UPG-H2-BIO-PYR	Bio-oil pyrolysis	Whole tree	0.52	2.11	0.57	\$/kg H_2	1.6	20	Sarkar and Kumar (2010b)
CSS: Steam generation									
Reference	Boiler steam	Natural gas	1.48	0.12	1.64[a]P_{NG}	\$/bbl bitumen	63.6	20	Kraemer et al. (2009)
CSS-STEAM-SOL	Solar steam plant	Solar	16.23	6.75	–	\$/bbl bitumen		20	Kraemer et al. (2009)
SAGD: Steam generation									
Reference	Boiler steam	Natural gas	1.14	0.09	1.30[a]P_{NG}	\$/bbl bitumen	56.3	20	Bersak and Kadak (2007)
SAGD-STEAM-NUC-MOD	Small modular nuclear reactor	Nuclear	6.41	1.03	1.39	\$/bbl bitumen		20	Bersak and Kadak (2007)
Surface mining: Process heat supply									
Reference	Natural gas boiler	Natural gas	–	–	0.36[a]P_{NG}	\$/bbl bitumen	41	20	Pathak et al. (2014)
SM-HEAT-GEO	Geothermal - High well flow	Geothermal	1.71	1.05	–	\$/bbl bitumen	14.4	30	Pathak et al. (2014)
Electricity supply									
Reference	Provincial grid electricity	n/a	n/a	n/a	7.72[a]P_E	\$/MWh electricity	Table 4	n/a	LEAP-Oil Sands
ELEC-NUC-ACR	700 MW ACR700 reactor	Nuclear	44.24	18.04	5.45	\$/MWh electricity	–	30	Bersak and Kadak (2007)
ELEC-HYD-DAM	1,100 MW Hydro Dam (BC Site C)	Hydro	115	7.51	–	\$/MWh electricity	–	70	BC Hydro (2019)

[a] P_{NG} = price of natural gas [\$/GJ]; P_E [\$/MWh]; \$ = 2019 CAD.

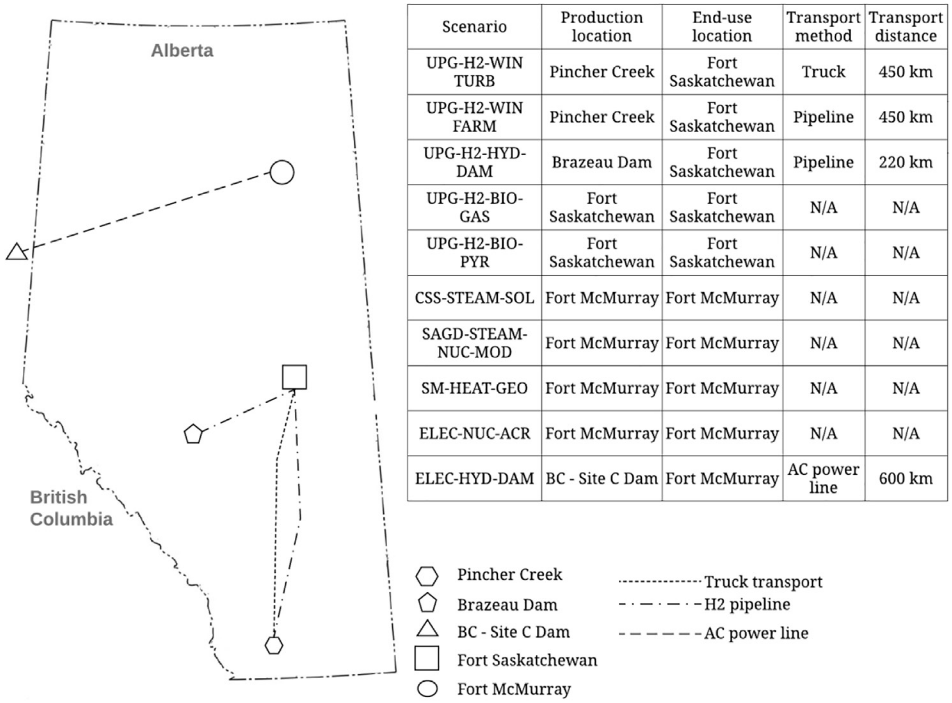
natural gas prices, electricity prices are derived from production forecasts by the CER (CER, 2018), shown in Fig. 4. CER data is provided to the year 2040 and trends are extrapolated to 2050 based on a linear trendline from 2036 to 2040. For bitumen upgrading, 3.4 kg of H_2 was assumed to be required per barrel of SCO production (Olateju and Kumar, 2013). Electricity demands (Fig. 4) and the provincial electricity grid factor (Table 4) were derived from the updated LEAP-Oil Sands model. 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. For the electricity generation scenarios, due to the large size of nuclear and hydro power plants considered, a minimum level of electricity production is required before market share is allocated. These levels correspond to a 703 MW nuclear plant at 90% capacity factor and 1,100 MW hydro plant with 54% capacity factor. Once the market share model produces the minimum electricity generation for a plant, the electricity production from the plant is allocated.

2.4. LEAP-Oil sands model and cost-benefit analysis

The LEAP modelling system was used to calculate the annual GHG emissions, determine the GHG emission mitigation, and calculate the marginal GHG abatement cost for each scenario. The LEAP modelling in this study is a continuation of the LEAP-Oil Sands modelling from earlier work (Katta et al., 2019). This was model was developed with a bottom-up structure where end-use devices and processes in each oil sands extraction processes, and upgrading, are defined with activity levels and fuel-specific energy-intensities. While no modifications or additions of energy intensities were made for this study, the existing energy intensities in the model were used to determine the total GHG emissions in the oil sands, to analyze the contributions that the renewable and low-carbon technology scenarios may have on long-term sector-wide GHG reduction targets. For additional information on the development of the LEAP-Oil Sands model, the reader is referred to Katta et al. (2019) for a complete account of the model.

Production data in the model was updated with the projections presented in the previous section. The model was further developed by adding new technology branches and scenarios with the techno-economic data sets for each renewable/low carbon energy technology scenario in this study, which included emission factors, activity (market penetration), and marginal LCC costs with respect to the reference scenario. For electricity scenarios, the electricity processes were added to the model corresponding to the capacities achieved in the market penetration model and capacity factors. The plants are dispatched as first merit order and the remaining electricity demands are met by oil sands cogeneration at second merit (capacity given in Table 5) and grid electricity at final merit.

The marginal GHG abatement cost (MAC) in dollars per



Scenario	Production location	End-use location	Transport method	Transport distance
UPG-H2-WIN TURB	Pincher Creek	Fort Saskatchewan	Truck	450 km
UPG-H2-WIN FARM	Pincher Creek	Fort Saskatchewan	Pipeline	450 km
UPG-H2-HYD-DAM	Brazeau Dam	Fort Saskatchewan	Pipeline	220 km
UPG-H2-BIO-GAS	Fort Saskatchewan	Fort Saskatchewan	N/A	N/A
UPG-H2-BIO-PYR	Fort Saskatchewan	Fort Saskatchewan	N/A	N/A
CSS-STEAM-SOL	Fort McMurray	Fort McMurray	N/A	N/A
SAGD-STEAM-NUC-MOD	Fort McMurray	Fort McMurray	N/A	N/A
SM-HEAT-GEO	Fort McMurray	Fort McMurray	N/A	N/A
ELEC-NUC-ACR	Fort McMurray	Fort McMurray	N/A	N/A
ELEC-HYD-DAM	BC - Site C Dam	Fort McMurray	AC power line	600 km

Fig. 3. Overview of scenario locations and commodity transportation methods (map taken from NRCan and used in accordance with the Canadian Open Government Licence (NRC, 2002)).

Table 3
Scenario inputs to penetration model.

Sector: Energy product Scenario name	Annual lifecycle cost (LCC) [2019 CAD $/Unit produced][a]
Upgrading: Hydrogen supply ($/kg-H$_2$)	
Reference	$1.15 + 0.15{*}P_{NG,\,y} + 0.0119{*}ECC_y$
UPG-H2-WIN-TURB	$14.39 + \mathit{0.0064}{*}ECC_y$
UPG-H2-WIN-FARM	$9.69 + 0.0016{*}ECC_y$
UPG-H2-HYD-DAM	$2.58 + 0.0016{*}ECC_y$
UPG-H2-BIO-GAS	$2.55 + 0.0012{*}ECC_y$
UPG-H2-BIO-PYR	$2.76 + 0.0016{*}ECC_y$
CSS: Steam generation/process heat supply ($/bbl)	
Reference	$1.39 + 1.43{*}P_{NG,\,y} + 0.0636{*}ECC_y$
CSS-STEAM-SOL	19.81
SAGD: Steam generation/process heat supply ($/bbl)	
Reference	$1.23 + 1.30{*}P_{NG,\,y} + 0.0563{*}ECC_y$
SAGD-STEAM-NUC-MOD	8.1
Surface mining: Process heat supply ($/bbl)	
Reference	$0.32{*}P_{NG,\,y} + 0.041{*}ECC_y$
SM-HEAT-GEO	$2.6 + .0144{*}ECC_y$
Electricity supply ($/MWh)	
Reference	$P_{E,y} + GF_y{*}ECC_y$
ELEC-NUC-ACR	74.5
ELEC-HYD-DAM	122.85

[a] P_{NG} = price of natural gas [$/GJ]; P_E = price of electricity [$/MWh]; ECC = emitted carbon cost [$/tonne CO$_2$e]; GF = grid factor [kg/MWh] given in Table 4; y = year.

equivalent tonnes of carbon dioxide ($/tCO$_2$e) was derived from the model for each scenario, and used to develop the marginal abatement cost curve for cost-benefit analysis. The marginal abatement cost for each scenario is based on Equation (4), where $SC_{x,y}$ is the annual cost associated with implementing scenario x in year y, $SC_{BAU,y}$ is the annual cost of the reference scenario in year y, $SE_{BAU,y}$ is the GHG emissions in the reference scenario in year y, and $SE_{x,y}$ is the absolute GHG emissions from scenario x in year y. All calculations were performed in 2019 CAD and annual net costs were discounted at a rate of 5% to2019. Effectively, the numerator is the marginal net present value of each scenario and the denominator is the cumulative GHG mitigation, with respect to the reference case.

$$MAC_x = \sum_{n=i}^{n} \frac{\sum_{2019}^{y}\left(SC_{x,y} - SC_{REF,y}\right)}{\sum_{2019}^{y}\left(SE_{REF,y} - SE_{x,y}\right)} \tag{4}$$

Table 4
Electricity grid emission factor.

Branches	2019	2025	2030	2035	2040	2045	2050
Alberta grid GHG emission factor (kg/MWh)	552	439	306	280	254	250	250

Table 5
LEAP-Oil Sands updated cogeneration electricity supply parameters.

Branch	2019	2025	2030	2035	2040	2045	2050
Oil sands cogeneration capacity (MW)	3,841	4,986	5,393	5,548	5,155	5,263	5,203
Oil sands cogeneration capacity maximum availability	70%	70%	70%	70%	70%	70%	70%

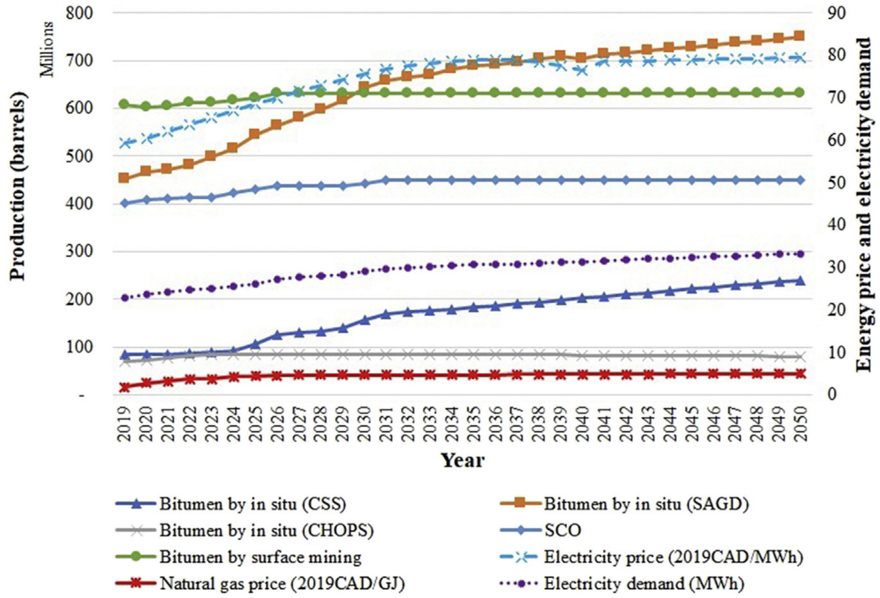


Fig. 4. Oil sands activity projections and energy prices.

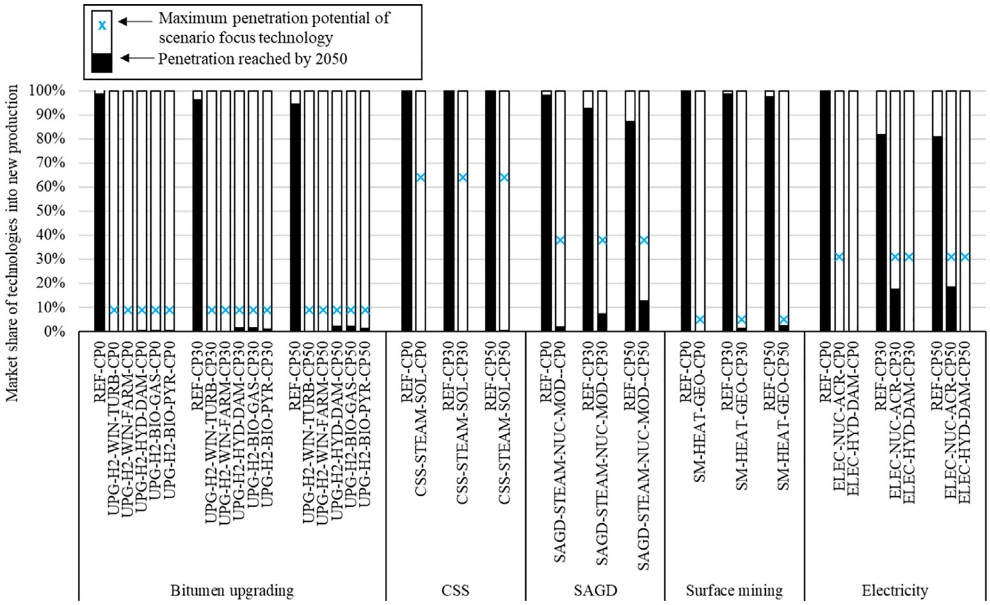


Fig. 5. Market share results in 2050 by scenario based on maximum subsector penetration potential.

2.5. Sensitivity analysis

The sensitivity of market penetration and GHG abatement cost results to key variables – cost variance parameter, capital, 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 LCC value 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.

3. Results and discussion

3.1. Market penetration

Fig. 5 gives the market penetration results in each scenario. The y-axis of the figure represents the percent of new production since 2019 that the renewable and low-carbon technologies captured by 2050. Alternative hydrogen production technologies have potential to gain up to 9% of total sector production by 2050, based on the projected growth in SCO production. The penetration results from this subsector show that biomass gasification (UPG-H2-BIO-GAS-CP50) and hydro electrolysis hydro dam (UPG-H2-HYD-DAM-CP50) will gain the largest market share, capturing 2.2% and 2.1% of the total by 2050 under the highest carbon pricing considered, respectively. 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, UPG-H2-BIO-GAS finished with 0.5% of the hydrogen market with no carbon incentive and 2.2% under the highest carbon incentive because of the reduced carbon emissions associated with the renewable hydrogen options. Wind energy scenarios (UPG-H2-WIN-TURB and UPG-H2-WIN-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. The results show that the renewable technology scenarios 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. Nuclear modular reactors producing steam for SAGD (SAGD-STEAM-NUC-MOD scenarios) gained 2–13% of the market of new production. 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. 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 (Bersak and Kadak, 2007). Solar-based steam scenarios did not gain any market shares in the CSS subsector during the analysis period due to its relatively high costs.

Geothermal energy was considered for bitumen extraction process heat in surface mining applications (SM-HEAT-GEO). The maximum penetration possible in surface mining was found to be 5% by 2050 considering penetration into new production between 2019 and 2050. The SM-HEAT-GEO scenario resulted in geothermal-based heat gaining between 0.05% and 2.6% of the total surface mining market by 2050.

Hydroelectricity (ELEC-HYD-DAM) and nuclear electricity (ELEC-NUC-ACR) were both considered in the electricity generation subsector of the oil sands industry. Because of industry-wide increasing electricity demand driven by projected growth in various subsectors that use electricity, the maximum penetration in the electricity subsector was forecast to be 31%. ELEC-HYD-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 ELEC-NUC-ACR justified constructing one reactor in both carbon pricing scenarios and resulted in a final-year market share of 19%. Because of the higher carbon pricing in CP50, the reactor could be justified earlier and therefore is expected to offer higher emission abatement potential.

The effects of carbon incentives on technology penetration varied across the scenarios and generally resulted in increased penetration. Nuclear electricity scenarios (ELEC-NUC-ACR) did not gain any market shares in CP0 but gained 19% 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 (SAGD-STEAM-NUC-MOD), the 2050 market shares were 2%, 8%, and 13% for no carbon incentive, CP30, and CP50, respectively.

3.2. GHG emissions mitigation

The cumulative mitigation potentials considering all the technologies for the 2019–2050 evaluation period under CP0, CP30, and CP50 are 15 MT, 84 MT, and 133 MT, respectively. These values translate to 0.4%, 2.3%, and 3.7% reductions in total oil sands emissions for the three scenario sets. The results show significantly increased penetration and GHG emission reductions due to carbon incentives, with the CP50 scenarios providing 119 MT more abatement potential than the CP0 scenarios. These results are mainly driven by the nuclear SAGD steam (SAGD-STEAM-NUC-MOD) and nuclear electricity (ELEC-NUC-ACR) scenarios, which show 12 MT and 0 MT of cumulative abatement potential in CP0, and 81 MT and 34 MT of cumulative abatement potential in CP50.

Fig. 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 (GOA, 2017a), therefore upgrading subsector scenarios and electricity emissions from cogeneration were not included in the GHG emissions cap relevant scenario results. All scenarios show the GHG emissions cap will be exceeded by 2030. The scenarios that achieved a notable impact on GHG emissions over the study period is the nuclear SAGD steam (SAGD-STEAM-NUC-MOD-CP30) scenario and the nuclear electricity scenario (ELEC-NUC-ACR). The nuclear-SAGD scenario shows a gradual increase in GHG mitigation whereas the nuclear-electricity scenario has a step wise GHG reduction trend beginning in 2037. This is because penetration levels reach a point where

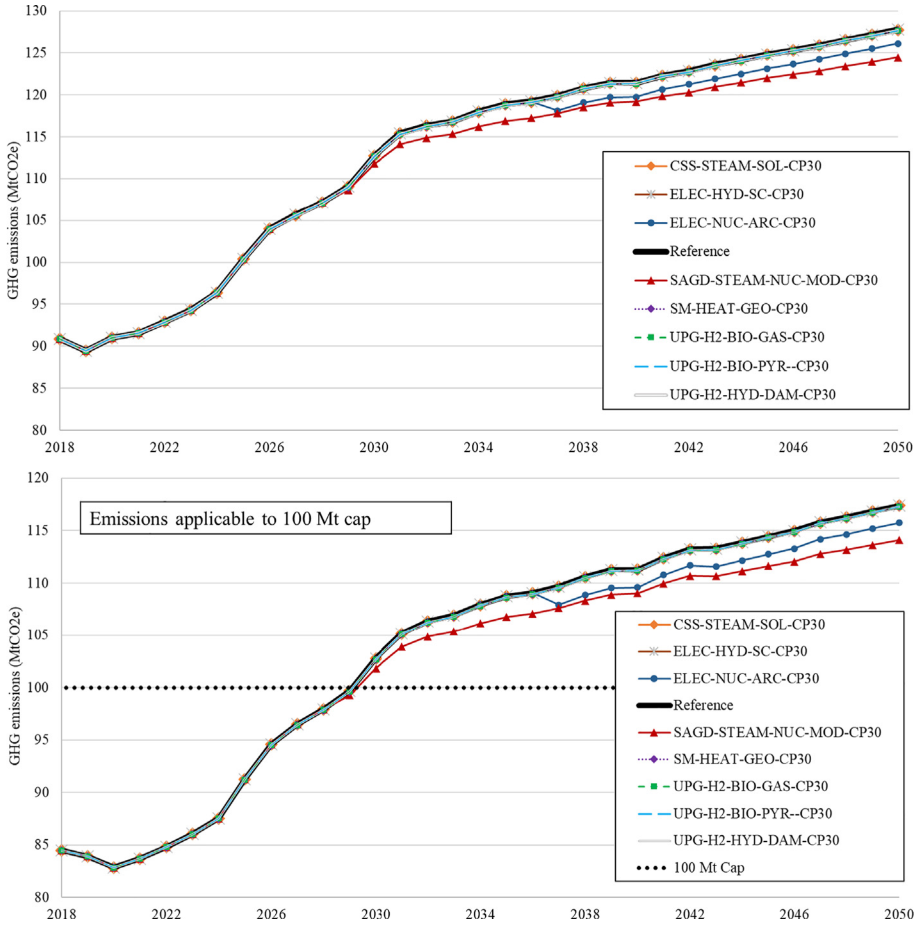


Fig. 6. CP30 scenario annual emission results including total emissions (top) and emissions cap (bottom) relevant emissions.

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 increases from 0% to 18% and thus makes a noticeable impact on overall GHG emissions when the facility begins to generate electricity. These renewable and low-carbon technology scenarios show that they alone may not be able to reduce emissions enough to meet the emissions cap policy. However, nuclear technologies can account for a large portion of the required emission reduction, 28% of the 2050 reduction requirement to meet the cap.

Fig. 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 (SAGD-STEAM-NUC-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

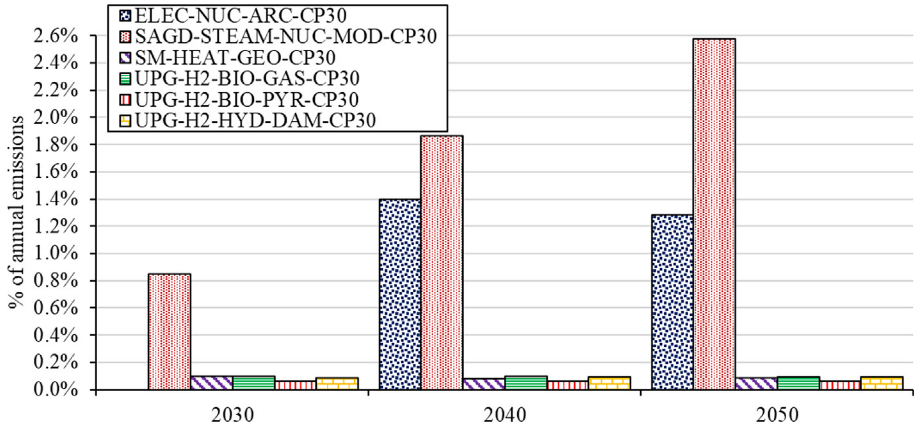


Fig. 7. GHG mitigation as a percent of annual total oil sands emissions by scenario.

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 2035 under CP30 conditions, thus the scenario offers no mitigation potential until later years. This delay means in a low cumulative abatement potential of the nuclear electricity scenario, despite high penetration levels after the facility is constructed.

3.3. *Marginal GHG abatement cost curves*

The cost curves in Fig. 8 depict the mitigation potential and associated cost forecasted for each scenario in the 2019–2050 evaluation period under each carbon incentive option. Because all the scenarios can be implemented together, the total mitigation possible for each carbon incentive is shown in the highest horizontal axis value.

With no carbon price incentives none of the scenarios offered GHG mitigation with cost savings and scenario marginal abatement costs ranged from 33 to $65/t. Nuclear electricity (ELEC-NUC-ACR) shows cost savings and relatively significant GHG mitigation at a $30/t carbon price, with 23 MT of GHG abatement at -$14/t. With a $50/t carbon price incentive, nuclear-based electricity and steam, and geothermal-based process heat scenarios show a net cost benefit by 2050 and high GHG mitigation compared to other scenarios. Total GHG mitigation considering the scenarios that have a negative marginal abatement costs with the $50/t carbon price is 121 MT. Implementing all the scenarios together results in marginal cumulative mitigation costs of $37/tCO$_2$e at CP0, $1/tCO$_2$e at CP30, and -$6/tCO$_2$e 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 substantially from the no carbon pricing to a $30/t and further to $50/t. Following the CP50 policy framework resulted in 133 MT of GHG abatement (3.8% of cumulative total oil sands emissions) and negative marginal abatement costs indicating that implementing these technologies to reduce GHG emissions at the modeled conditions also results in long-term cost savings for the industry.

3.4. *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 sensitivity analysis was conducted on market penetration results over a range of cost variance values (v) used in Equation (2), with results shown in Fig. 9. At lower values close to 1, ELEC-ELEC-NUC-ACR-CP30 did not achieve the minimum production for a single facility, therefore the 2050 penetration results was 0%. The CSS scenarios is also sensitive to the lower cost variance parameter as the solar technology gained significantly higher market shares compared to the reference value as higher amounts are adopted even with a relatively large cost differential.

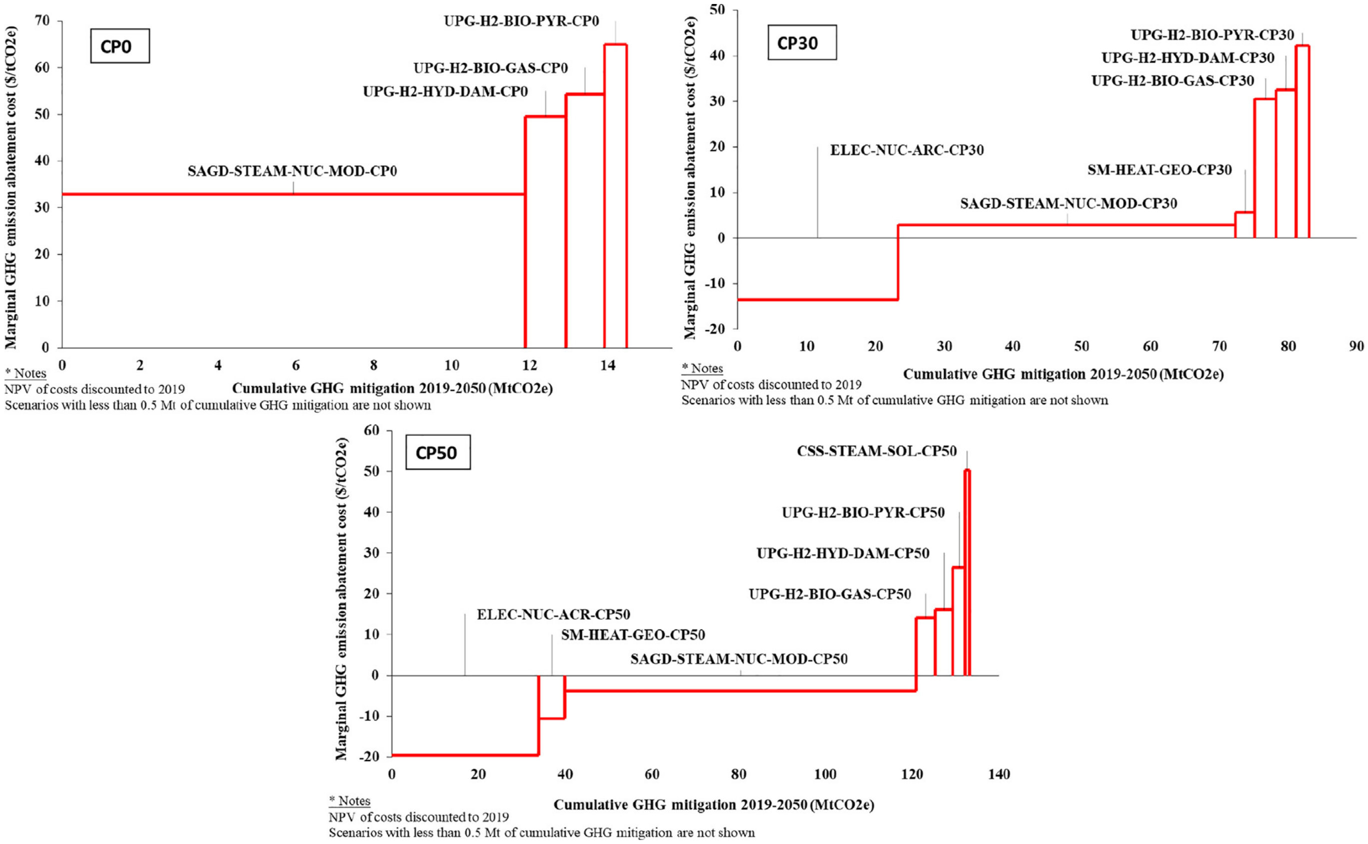


Fig. 8. 2019–2050 GHG mitigation cost curves with no carbon price (top left), $30/t carbon price (top right), and $50/t carbon price (bottom).

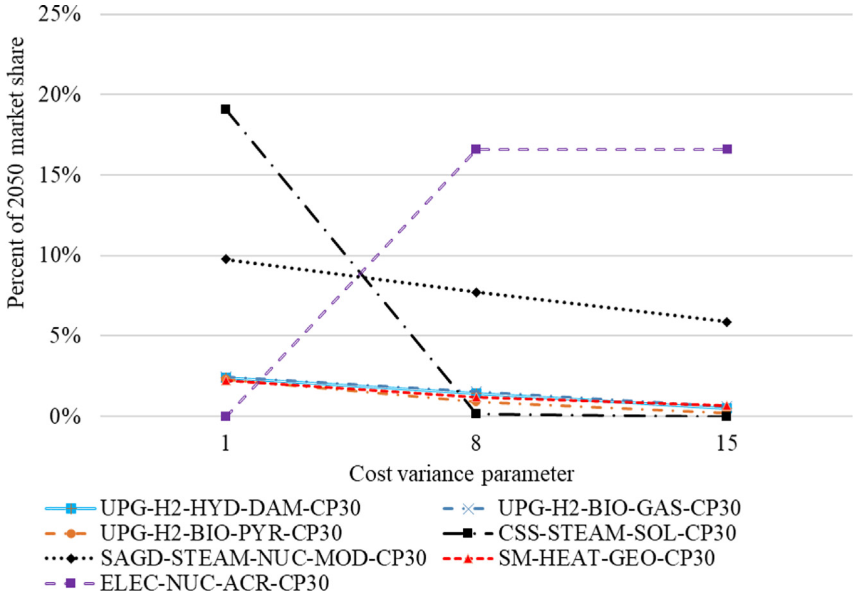


Fig. 9. Sensitivity of the 2050 sector-specific market share results to changes in the cost variance parameter.

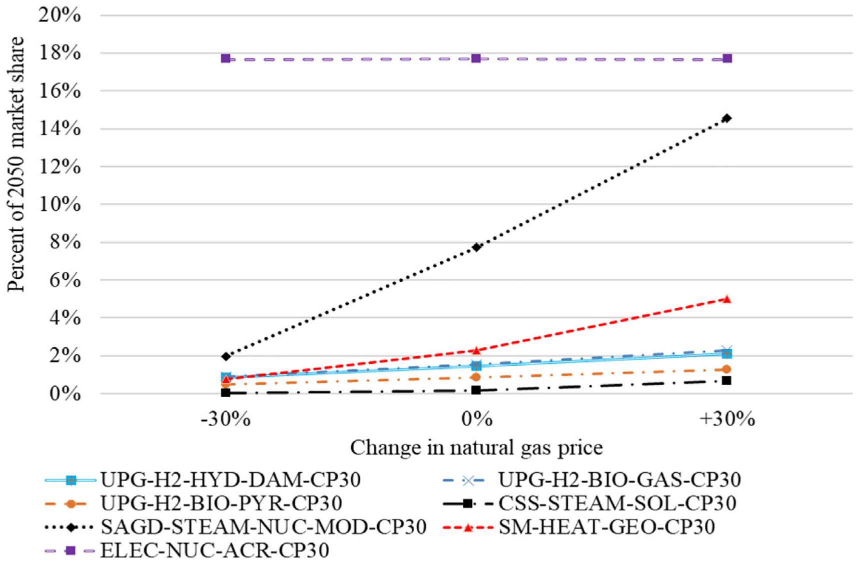


Fig. 10. Sensitivity of 2050 market share results to changes in the annual natural gas prices.

Fig. 10 shows the expected 2050 market share of each scenario as the forecasted natural gas price is changed by ± 30%. The SAGD-STEAM-NUC-MOD-CP30 scenario changes most substantially, gaining only 2% of the market if natural gas prices are 30% lower than forecasted and gaining nearly 14.2% of the market if natural gas prices are 30% greater than expected. A change in electricity price projections have an impact on the market share of nuclear power in the ELEC-NUC-ACR-CP30 scenario, but no other scenarios (Fig. 11). A reduction by 30% did not produce a large enough market share for adoption of the nuclear power plant.

Fig. 12 shows the expected 2050 market share when the non-energy costs are varied by 30%. This includes the capital costs and operations and maintenance costs. While market share of the renewable and low carbon technologies increases across all scenario with lower non-energy costs, the most substantially impacted scenarios are the nuclear-based scenarios. Market share for nuclear technologies reduces to almost zero for a 30% increase in non-energy costs from relatively high levels of market share. Market share of small module nuclear reactors in the SAGD-STEAM-NUC-MOD-CP30 scenario increased significantly with reduce non-energy costs due to high market adoption rates for new production. Nuclear power market share did not change with lower non-energy costs since the scenario only considered adoption of 1 power plant, which was achieved at the baseline costs.

The sensitivity of marginal GHG abatement cost results to changing the forecasted natural gas price by ± 30% is shown in Fig. 13. The marginal abatement costs for most scenarios change linearly corresponding to 30% changes in natural gas prices. The ELEC-NUC-ACR-CP30 results do not change since nuclear power competition was based on industrial electricity prices.

The sensitivity of total abatement results to changes in industry growth is shown in Fig. 14. Market growth projections were

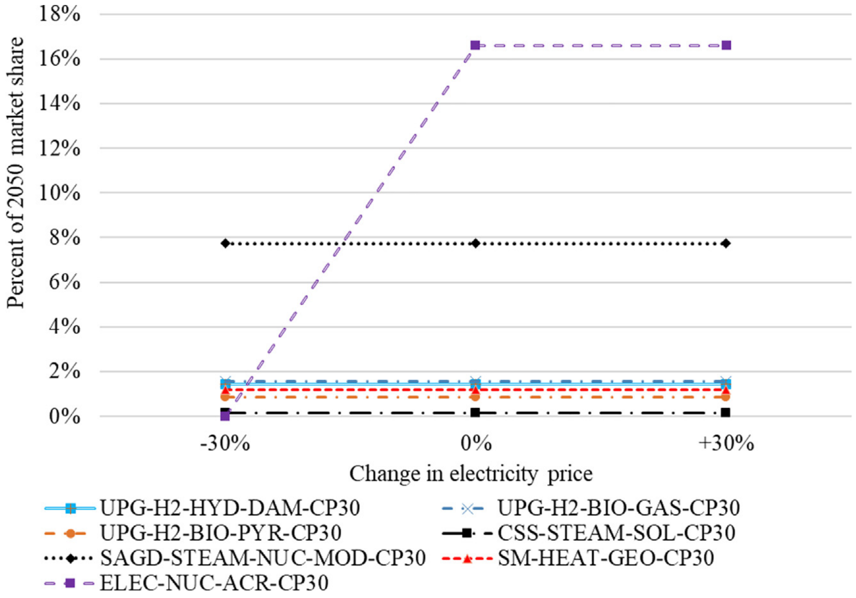


Fig. 11. Sensitivity of 2050 market share results to changes in the annual electricity prices.

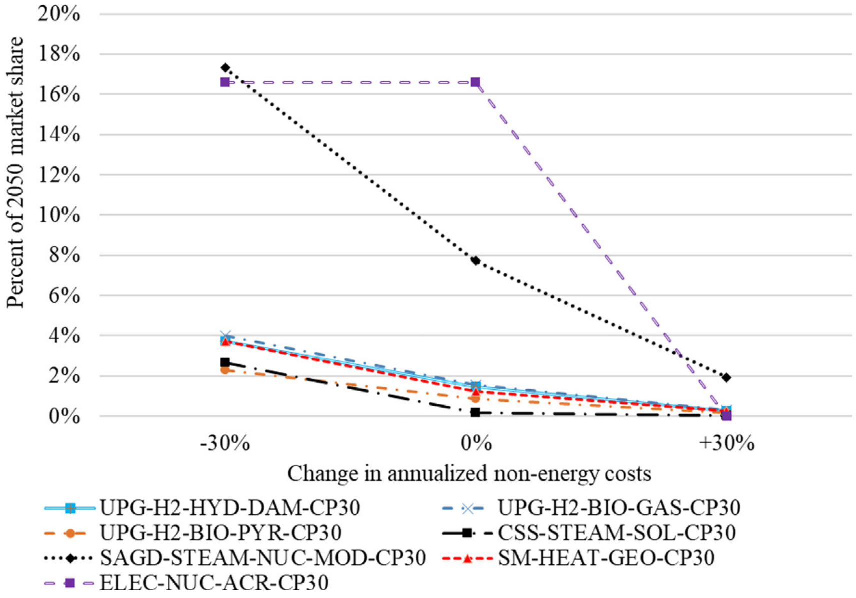


Fig. 12. Sensitivity of 2050 market share results to changes in annualized non-energy costs.

changed from −30% to +30% of forecast and the total abatement in each scenario was determined. 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 remaining scenarios changed linearly, with NUC - SAGD - MOD - CP30 differing most substantially corresponding to the large expected growth in the sector. The bitumen upgrading subsector scenarios varied similarly.

Fig. 15 shows the sensitivity of the marginal cost of GHG abatement results when non-energy costs are changed by −30% to +30%. The nuclear power scenario (ELEC-NUC-ACR-CP30) retained a negative marginal abatement cost despite a 30% increase in non-energy costs, though it approached a break-even value. Given that large nuclear power projects have high risk of going over budget, the robustness of this scenario in retaining negative abatement costs is an important factor. The CSS-STEAM-SOL-CP30 scenario retained a positive marginal abatement cost even with a 30% decrease in non-energy costs, thus, costs will need to be reduced even further than 30% to make this scenario a cost-effective strategy to reduce GHG emissions. Other scenarios responded with linearly changing marginal abatement costs corresponding to ± 30% changes in non-energy costs.

3.5. 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

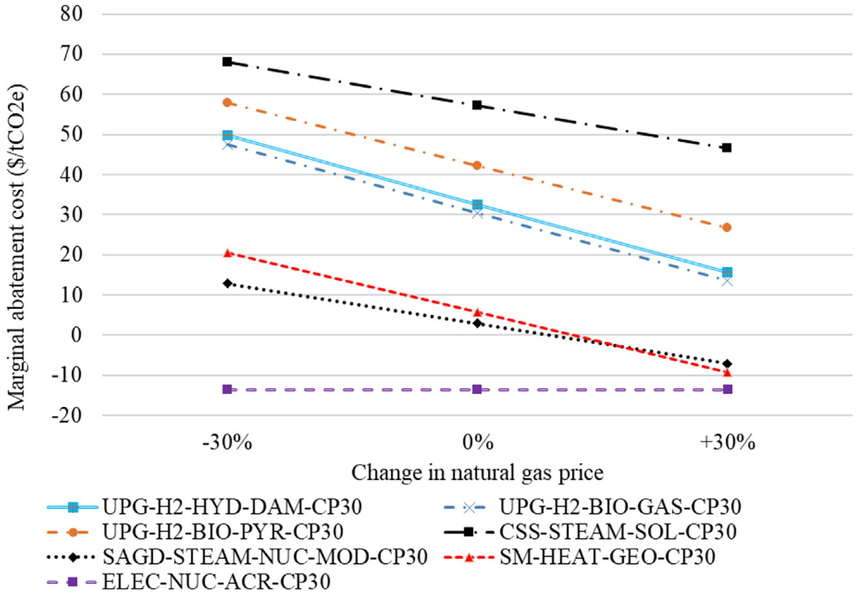


Fig. 13. Sensitivity of marginal cost of GHG abatement to changes in the natural gas price forecast.

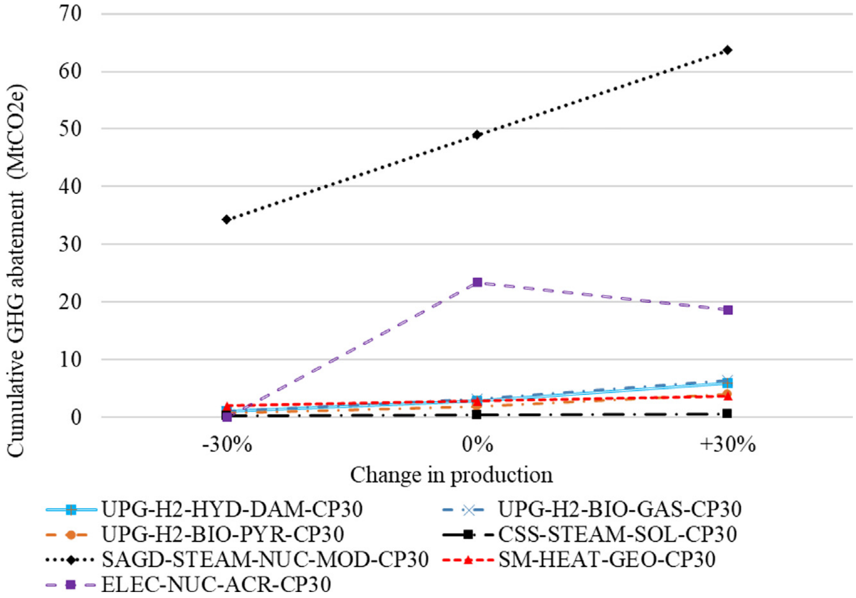


Fig. 14. Sensitivity of total GHG abatement potential to changes in the market growth forecast.

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 logistic 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 (NREL, 1993). 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-

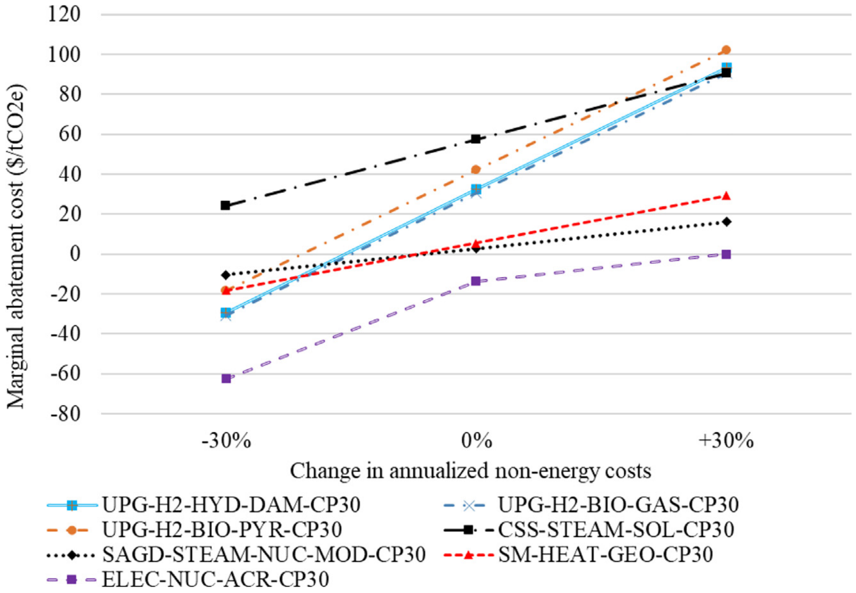


Fig. 15. Sensitivity of marginal GHG abatement cost results to changes in annualized non-energy costs.

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. 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), 133 MT of cumulative GHG emission mitigation was available with an average cost of -\$6/tCO_2e, showing a long-term cost benefit. The most promising technology investigated was the use of small modular nuclear reactors for SAGD steam, with 81 MT of mitigation at -\$4/tCO_2e under the \$50/tonne of CO_2 carbon incentive policy. The 100 MT emission cap was not met through any scenario, however nuclear technologies were shown to make up 28% of emission reduction requirements to meet the cap in 2050. Incorporating renewable energy technologies under current carbon incentive 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 market penetration parameters, 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.

CRediT authorship contribution statement

Ryan Janzen: Conceptualization, Methodology, Validation, Writing - original draft. **Matthew Davis:** Methodology, Investigation, Supervision, Writing - review & editing. **Amit Kumar:** Supervision, Investigation, Resources, Visualization, Writing - review & editing.

Declaration of competing interest

None.

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