

An assessment of opportunities for cogenerating electricity to reduce greenhouse gas emissions in the oil sands

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ABSTRACT

The purpose of this research is to evaluate greenhouse gas emission reduction opportunities from cogenerated electricity in oil sands production. A novel combined market penetration and bottom-up energy system modelling framework was developed to assess the long-range potential and marginal costs of cogenerated electricity in the oil sands. Feasible scenarios for incorporating cogeneration into the in situ, surface mining, and upgrading subsectors were developed along with four additional scenarios incorporating electricity-based technologies to improve in situ plant efficiencies. These scenarios were evaluated under three different carbon pricing policies; twenty-one scenarios in total covering the time period 2019 to 2050. The use of cogeneration in the oil sands for new production during this period was determined through market penetration modelling and the results were compared to a reference scenario of limited cogeneration growth. It was found that there is potential to provide 76 million tonnes of greenhouse gas abatement (2% of cumulative projected oil sands emissions) at a marginal cost of \$15 per tonne of carbon abated compared to the reference scenario. The incorporation of electrical equipment, specifically well-pad boilers, well-pad compressors, additional steam compressors, and steam superheaters, resulted in additional costs that outweighed the benefits. A \$50 per tonne of carbon dioxide equivalent carbon price (within the current Alberta emission reduction regulation) resulted in a 2% increase in forecasted greenhouse gas abatement potential and a \$1.4/tonne of carbon dioxide equivalent decrease in marginal abatement costs compared to no carbon pricing. This research provides quantification of the greenhouse gas emission abatement potential and marginal abatement costs of cogeneration technologies to allow industry stakeholders and policymakers to compare these technology options to others when considering long-term greenhouse gas emission reduction.

1. Introduction

Crude oil made up 32% of global energy production in 2017 and reports suggest that global energy demand will increase at a faster pace than the development of renewable energy for at least the next 20 years [1]. In 2017, Canada produced 5.6% of global crude oil [2], 65% of which was sourced from the oil sands [3]. 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 [4]. Crude oil production from the Canadian oil sands has close to doubled since 2010 and is expected to grow by another 41% by 2040 [3].

Crude oil mined from the Canadian oil sands is initially produced as bitumen and is processed before being sent to refineries. Bitumen production is energy-intensive and contributed approximately 10% of the national greenhouse gas (GHG) emissions in 2016 and accounted for 41% of the nation-wide oil and gas sector GHG emissions [5]. 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 [6]. The industry is expected to grow in the next 20 years [3]; 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 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 [7]. 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

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Nomenclature

bpd	Barrels per day	LCC	Life cycle cost
CC	Capital cost	LEAP	Long-range Energy Alternatives Planning
CER	Canada Energy Regulator	<i>n</i>	Lifetime in years
COG	Cogeneration	MWh	Megawatt-hour
CP	Carbon price	NG	Natural gas
EC	Energy cost	P	Price
ECC	Emitted carbon cost	OC	Operations and maintenance cost
ELEC	Electricity	SAGD	Steam-assisted gravity drainage
ES	Electric-steam superheaters	SC	Steam compressors
<i>i</i>	Interest rate	SCO	Synthetic crude oil
IPCC	Intergovernmental Panel on Climate Change	SM	Surface mining
IRR	Internal rate of return	UPG	Upgrading
<i>j</i>	Scenario	WB	Well-pad boilers
		WC	Well-pad compressors
		<i>y</i>	year

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 fossil fuels and electricity consumption, either from the grid or produced on-site [8]. Electricity is used to power various equipment including mobile mining equipment, conveyors, compressors, and pumps in surface mining; pumps, compressors, and mixers in situ production; and refining equipment in upgrading [9]. 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 and can often offer significant GHG abatement from those efficiency improvements [10]. Cogeneration can achieve around 90% overall thermal efficiency while producing steam and electricity separately can be up to around 85% and 54% efficient individually, respectively [11]. Recent studies have shown both the promise of cogeneration technology to reduce GHG emissions and the potential to improve the performance of the technology. A recent study concluded that expanding cogeneration capacity would be a vital component of meeting clean energy targets in Mexico, where similar levels of cogeneration capacity are found to those in Alberta [12]. Another recent study conducted a large scale literature review on cogeneration research and found that cogeneration systems offer a reliable and effective means of reducing GHG emissions in regions with high levels of fossil fuel-based electricity production, like Alberta [13]. 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 [14]. By 2015, the cogenerated electricity generation capacity from oil sands producers grew to 3343 MW in Alberta [15]. It is expected that oil sands cogeneration capacity will continue to grow [16].

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 by coal-fired power plants [17]. Alberta grid emission levels are 753 kg of carbon dioxide (CO₂)/megawatt-hour (MWh) as of 2019 [9], while cogeneration facilities are typically 390 kgCO₂/MWh [18]. 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. One study developed a facility level

energy model and determined that facilities with cogeneration can reduce emissions by up to 25% in surface mines and 50% in steam-assisted gravity drainage (SAGD) facilities per barrel of oil produced if the cogenerated electricity is displacing high emitting electricity sources [8]. 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 the efficiency and emission benefits attained from cogenerating steam and electricity, it has been proposed in the literature that increasing the amount of oil sands cogeneration would be a cost-effective GHG reduction strategy for the oil sands [18,19]. 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 [20]. 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 [21]. 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 [22]. 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 the authors' knowledge, current literature contains limited studies that investigate the long-term potential for oil sands cogeneration-based 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 [20]. 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 a significant opportunity to incorporate cogeneration and analysis of these would be valuable. 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 [21]. The study was limited in that it did not consider determining market penetration based on competing technologies and also considered proportional displacement of Alberta electricity capacity shares, which at the time included coal but, due to recent policy directly, coal will be phased out in Alberta by 2030.

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 a techno-economic market penetration

model was integrated with 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.

The results of this study can be used by industry stakeholders and policymakers to better understand the long-term potential of the evaluated technologies and structure policy or decisions 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:

- Develop feasible technology scenarios for cogeneration to be further implemented in the oil sands.
- Develop a market penetration model to determine the rate at which cogeneration could be expected to gain market share during the evaluation period.
- Develop associated marginal costs of those technologies which could be expected to gain market share during the evaluation period.
- Integrate 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.

2. Method

The method section is structured such that the overall framework is explained first in Section 2.1. The framework discusses the modelling approaches used, how they were integrated for the analysis, and the different stages of the analysis (namely scenario development, modeling, cost-benefit analysis, and sensitivity analysis). Section 2.2 discusses in detail how the scenarios of interest were developed. Section 2.3 explains the techniques used to model the scenarios. These include market penetration modelling to project cogeneration development, as well as bottom-up energy modelling to simulate the oil sands sector's energy supply and demand dynamics within the Alberta energy system. Section 2.4 gives an overview of how the cost-benefit analysis of

scenarios was conducted and Section 2.5 justifies the choice of variables for the sensitivity analysis.

2.1. Framework

Fig. 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) [23] bottom-up energy model developed by Davis et al. [24], 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 comparison of 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 GHGs.

2.2. Scenario development

Cogeneration scenarios were developed for surface mining, in situ, and upgrading subsectors of oil sands production and are described in Table 1. Scenarios were developed based on available data for SAGD, surface mining, and upgrading plants with and without cogeneration [25]. The in situ scenarios assume a 30 kbpd SAGD facility with 160 MW of electricity cogeneration capacity, sized to meet the facility heat requirements. Due to the large heat requirement in the form of steam for SAGD facilities [21], the amount of electricity generated in this scenario exceeds the electricity required on site, with 90% of electricity being exported to the grid [26]. This level of generation is in line with other similar-sized SAGD projects with cogeneration including

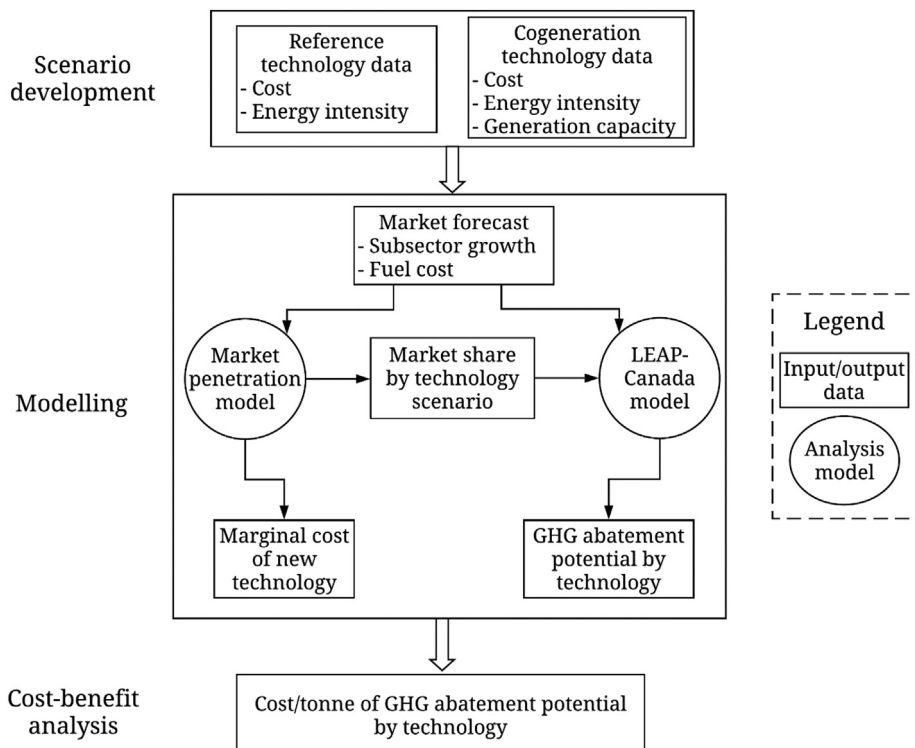


Fig. 1. Study framework illustrating how cogeneration scenarios were developed, modelled, and analysed.

Table 1
Scenario names and descriptions.

Scenario name	Description
<i>Steam assisted gravity drainage (SAGD)</i>	
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
<i>Surface mining</i>	
Reference	Surface mine with no cogeneration
SM-COG	Surface mine with cogeneration
<i>Bitumen upgrading</i>	
Reference	Upgrading with no cogeneration
UPG-COG	Upgrading with cogeneration

Mackay River (207 MW) and Long Lake (170 MW) [27]. The surface mining scenarios assume a 100 kbpd facility, where 50 MW of co-generated electricity capacity is used, and all the electricity is consumed on site. The upgrading scenarios assume a 100 kbpd upgrading facility that has 15 MW of cogenerated electricity capacity, all of which is consumed on site.

SAGD processes generate steam that is transported to injection wells. During transportation, some heat is lost and steam is condensed, resulting in a portion of the heating fluid needing to be removed and recycled. 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 [26], and the most promising of those were incorporated as scenarios in the present work to determine their long-term cost-benefits. 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 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.

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

Table 2
Normalized cost inputs to Eq. (1) for each scenario (\$/bbl of annual production).

Technology	Annualized capital cost	Operation and maintenance costs (OC)	Energy costs (EC*)
Reference – SAGD	1	0.5760	0.08579 * P _{NG} + 0.001137 * P _{ELEC1}
SAGD-COG	1.258	0.8121	0.1206 * P _{NG} – 0.006215 * P _{ELEC2}
SAGD-COG-SC	1.307	1.3272	0.06632 * P _{NG} + 0.002705 * P _{ELEC1}
SAGD-COG-WB	1.242	0.8594	0.1146 * P _{NG} – 0.005204 * P _{ELEC2}
SAGD-COG-WC	1.269	0.8752	0.1158 * P _{NG} – 0.005204 * P _{ELEC2}
SAGD-COG-ES	1.241	0.8594	0.1146 * P _{NG} – 0.005204 * P _{ELEC2}
Reference – Mining	1	1.161	0.03562 * P _{NG} + 0.001621 * P _{ELEC1}
SM-COG	1.022	1.178	0.0418 * P _{NG}
Reference – Upgrading	1	0.3355	0.04900 * P _{NG} + 0.0007766 * P _{ELEC1}
UPG-COG	1.005	0.3389	0.04954 * P _{NG} + 0.0004349 * P _{ELEC1}

* Energy costs derived from the multiplication of energy intensities and energy prices; 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 the Supplementary Information (SI).

be compared independently of policy decisions. The second, “CP30,” uses a price of \$30/tCO₂e in 2019 dollars, assumed to increase with inflation from 2019 to 2050, corresponding to the current industrial carbon pricing [28]. The third, “CP50,” uses a price of \$30/tCO₂e until 2021 and a price of \$50/tCO₂e increasing with inflation from 2022 to 2050, matching the price of carbon in the federal government’s Pan-Canadian Framework on Clean Growth and Climate Change [6].

2.3. Modelling

Two distinct models were developed to achieve the research objectives outlined in this study. The market penetration model was used to assess the ability of the technologies being considered to gain market share based on their projected costs compared to the reference technology. The results from the market penetration model were then used in the bottom-up energy accounting model, LEAP-Canada, where each technology option was considered in scenarios that allow the GHG emissions to be calculated and compared to the reference scenario.

2.3.1. Market penetration model

The market penetration model is based on the technique developed by an earlier study of the energy industry where annual market shares can be approximated based on life cycle costs and an inverse power function [29]. The method has been used and further developed in other energy-economy modelling research [30]. The inverse power function has also been applied to mineral mining technologies for a similar analysis as the present study [31]. First, the annualized cost of each scenario, *j*, is calculated using capital costs, operating expenses, carbon costs, and energy costs using Eq. (1):

$$LCC_{j,y} = \left(CC_j \times \frac{i}{1 - (1 + i)^{-n}} \right) + OC_j + ECC_{j,y} + EC_{j,y} \tag{1}$$

where, *LCC_{j,y}* is the annualized lifetime cost of technology *j* in year *y*, *CC* is the capital cost, *i* is the interest rate, *n* is the technology expected life in years, *OC* is the annual operation and maintenance costs which exclude fuel costs, *ECC* is the annual emitted carbon cost (if a carbon pricing policy is in place), and *EC* is the annual energy cost.

Inputs into Eq. (1) were determined from cost data with and without cogeneration for SAGD, surface mining, and upgrading project types [25]. A value of 10% for the interest rate (*i*) was used. Cogeneration scenario energy and cost input data were verified to be reasonably comparable to the ranges of more recent dataset values from peer-reviewed literature on energy consumption for SAGD and surface mining plants [8] and upgrading plants [32], and their associated costs [33], as well as data ranges from industry [34] and provincial [35] and federal [36] government sources. Furthermore, a sensitivity analysis was conducted on capital cost and energy prices. The energy cost component of Eq. (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. *LCC* values between the reference and cogeneration technologies within a subsector were normalized to the reference technology capital cost. Table 2 shows the input values for Eq. (1) for the reference case and each scenario. The carbon cost component differs depending on the policy, the actual taxable emissions are based on process-specific emission benchmarks outlined in the regulation and were accounted for in the modelling in this study [28]. GHG emissions above the given benchmarks are taxable and GHG emissions below are subject to credit.

The *LCC* values were entered into the inverse power function shown in Eq. (2), which simulates the competition of technologies, assigning an annual market share to each technology j also presented in literature:

$$MS_{j,y} = \frac{LCC_{j,y}^{-v}}{\sum_{j=1}^k LCC_{j,y}^{-v}} \quad (2)$$

where, $MS_{j,y}$ is the market share for technology j in year y , 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 the literature [37] and determine the slope of the logistic curve corresponding to Eq. (2). Here, this represents how much of the new market favors the lowest cost option. A low cost variance value results in the price differential of competing technologies having less of an impact on decisions. Higher values produce market shares that more strongly favor the less costly option. A value of 8 is used in this study, which corresponds to a 10% price differential resulting in about a 32% new market capture for the more costly option. This is a conservative estimate since literature has found an empirical value of 1.4 [38] meaning that the cost differential has not influenced choice to a large degree, close to 47% new market capture for the more costly option for a 10% price differential. However, this empirical value was determined under a specific set of other parameter values, equations, and past data. To try and account for the uncertainty in the accuracy of this value for the present study, the sensitivity of results to this parameter is assessed from a value of 1.4 to 10 to cover a range of values that have been proposed in the literature. Once the annual market share is calculated, the total production assigned to each technology in any given year is determined by multiplying that market share by the forecasted new production.

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. Eqs. (1) and (2) are used to determine how much of that maximum penetration potential each technology could feasibly take based on their costs.

2.3.2. Energy-environmental 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 [24] and the oil sands [9] in previous work. For the present study, Katta et al.'s oil sands demand module [9] was integrated with the Alberta portion of Davis et al.'s LEAP-Canada model [24] and the latest projections from the Canadian Energy Regulator (CER) [3] and Alberta Electricity Systems Operator (AESO) [16] 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-Canada 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. [9] for the oil sands and in Davis et al. [24] for all other sectors. The time-varying nature of electricity demands is modelled with AESO's Alberta-specific load curve [39]. From this modelling, the annual peak-load is determined and the required firm electricity supply system capacity is calculated according to a specified 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, taken to be 15%. The maximum availability of cogeneration plants is assumed to be 75%. The Alberta electricity generation technology mix modelled capacities and parameters are given in the SI. Combined cycle technology capacity is added endogenously to meet the total required system capacity after deducting oil sands cogeneration from the total capacity requirements for each scenario. Dispatch of processes occurs on a merit order basis to meet demand. 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.

There are multiple acceptable methods for accounting the costs and energy savings from using combined heat and power systems [40]. In this model the energy savings are accounted for in the electricity generation module. This results in a modelled process efficiency of co-generated electricity of 61%, which accounts for the energy savings associated with using the waste heat from the steam generation segment [41]. The efficiency value used for cogenerated electricity in the model is also tested in the sensitivity analysis.

The additional SAGD scenarios incorporating electricity-based equipment were modelled by changing the electricity and natural gas end-use energy intensities according to the scenario energy requirements [26]. The changes in natural gas energy intensity due to cogeneration was deducted from the end-use energy intensities as additional natural gas requirements due to cogeneration were captured in the transformation processes. The emissions for electricity generation were calculated in LEAP using IPCC emission factors [42] and feedstock fuel requirements, which were determined by the process efficiency and electricity generation.

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 Eq. (3):

$$\text{Marginal abatement cost}_j [\$/\text{tonne}] = \sum_{y=2019}^y \frac{AC_{j,y} - AC_{REF,y}}{E_{REF,y} - E_{j,y}} \quad (3)$$

where *Marginal abatement cost_j* is the marginal abatement cost of scenario j per tonne of GHG emission abatement, $AC_{j,y}$ is the annual monetary cost of scenario j in year y , $AC_{REF,y}$ is the annual monetary cost of the reference scenario in year y , $E_{REF,y}$ is the GHG emissions associated with the reference scenario in year y , and $E_{j,y}$ is the GHG emissions associated with the scenario j in year y . Annual costs were discounted to the base year 2019 at a 5% rate.

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 1.4 to 10, to determine the effects on results based on the proposed values in the literature. The capital costs were adjusted by $\pm 30\%$ to account for site-specific variability and changes to costs in the time since the source data was published. Natural gas and electricity prices inherently fluctuate in the global and local markets and are difficult to predict; therefore, the results were tested by $\pm 20\%$ of forecasted prices. The 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 $\pm 20\%$. Cogeneration efficiency is varied by $\pm 10\%$ to understand the impact the facility efficiency has on the final results. Given Alberta's electricity sector transition away from coal (coal to be phased out by 2030) and to more natural gas and renewables (30% renewable generation by 2030), the results sensitivity to the electricity emission factor, used for carbon obligations/credit allocations was tested by varying the value $\pm 20\%$. Lastly, a sensitivity analysis was completed considering a scenario without a performance benchmark for carbon pricing at a $\$50/tCO_2e$ carbon price. In other words, instead of carbon pricing being charged on only a portion of emissions, all emissions are charged.

3. Results and discussion

The results and discussion section is broken down into 4 key sets of results, as well as a discussion of the limitations of the study. Section 3.1 gives the market penetration results for each scenario and subsector; Section 3.2 discusses the associated GHG abatement potential; Section 3.3 presents the cost-benefit analysis results and gives the marginal abatement cost curve; Section 3.4 provides results of the sensitivity analysis; Section 3.5 discusses the limitations of the study.

3.1. Market penetration results

The 2030 and 2050 market penetration results for further integration of cogeneration into the in situ - SAGD, surface mining, and upgrading subsectors are shown in Fig. 2. The SAGD subsector showed the highest maximum penetration potential at 43% in 2030, of which the cogeneration scenario captured 16%, 16.6%, and 16.7% in the CP0, CP30, and CP50 scenarios. The mining subsector had a maximum of 26% penetration potential, with all growth occurring before 2030, and the cogeneration scenarios captured 8% at CP0 and 8.2% at CP30 and 8.3% at CP50 carbon pricing. Finally, the upgrading subsector had a maximum of 20% available market penetration potential in the evaluation period, and cogeneration scenarios captured 6.8% in all carbon

price scenarios in 2030. No changes were observed between the 2030 and 2050 penetration results for the surface mining subsector because no growth is expected in that subsector after 2030. SAGD scenarios averaged a 0.6% penetration decrease from 2030 to 2050 due to forecasted electricity prices becoming slightly less favorable for cogeneration revenue over time. The results show that carbon pricing has little impact on the penetration of these technologies, which increases on average by 0.2% 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 make up a much more significant portion of the total costs than the carbon costs incurred in the current Alberta carbon policy framework.

Fig. 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 [26]. Because of the cost increases and lack of significant performance or environmental gains, none of the considered options outperformed the SAGD cogeneration scenario in the long term. 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 14.0%, 14.1%, and 14.1% in the CP0, CP30, and CP50 scenarios, respectively, by 2050. These scenarios attained on average 2.5% less penetration than the SAGD cogeneration scenario. Electric well-pad compressors and electric-steam superheaters attained 4.2% and 2.5% 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 and other relevant modelled factors such as the provincial grid mix, natural gas prices, electricity costs, and carbon policy.

3.2. Greenhouse gas emission abatement potential

Due to the minimal change in penetration results between CP0, CP30, and CP50 scenarios, only CP30 scenario results are shown in this section. Results for CP0 and CP50 scenarios can be found in the Supplementary Information. The annual GHG abatement potential is for CP30 scenarios is illustrated in Fig. 3. The SAGD cogeneration scenario (SAGD-COG) achieves the most mitigation every year compared to

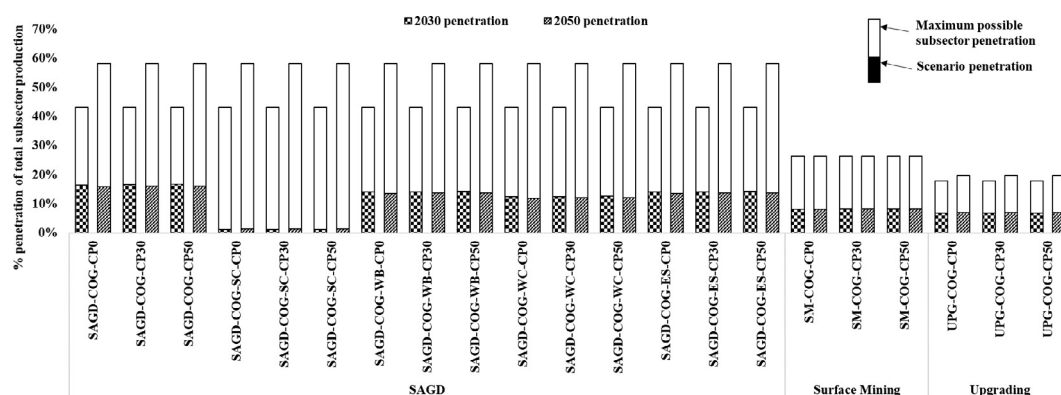


Fig. 2. Market penetration results for cogeneration scenarios in the 2030 and 2050 time frames.

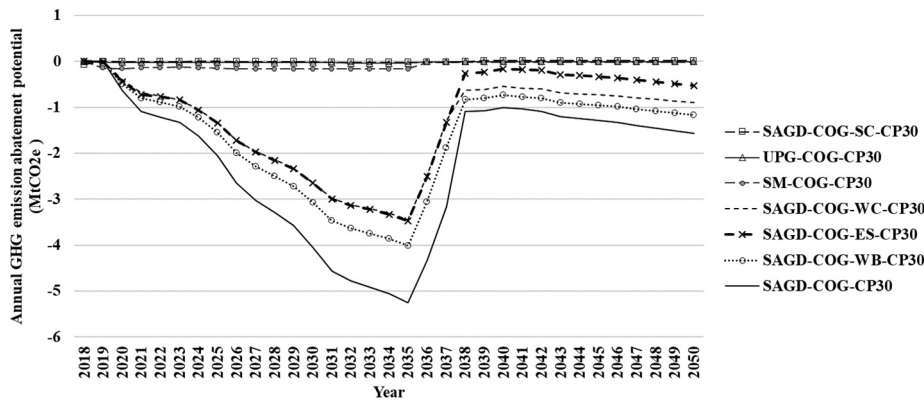


Fig. 3. Annual GHG emission abatement by scenario compared to the reference scenario.

other scenarios. The surface mining and upgrading cogeneration scenarios (SM-COG, UPD-COG) experience a relatively small amount of GHG mitigation. None of the electric technology scenarios considered in the SAGD subsector resulted in higher GHG mitigation than the SAGD cogeneration scenario. The well-pad boiler scenario performed the best out of the alternative options. The key reason these scenarios were outperformed by the initial SAGD cogeneration scenario was that the added costs of incorporating the new technology reduced the market penetration, thereby limiting the impact of the scenario on overall emissions.

The trend in increasing annual mitigation to 2035 and decreasing mitigation between 2035 and 2050 can be explained by reviewing Fig. 4. Fig. 4 shows the electricity generation GHG emissions for the SAGD-COG-CP30 scenario. In the years up to 2037, GHG emission mitigation is highest because a portion of natural gas simple cycle and converted coal to gas plant electricity generation is displaced by the electricity generated by oil sands cogeneration. The capacity factor of the converted coal to gas plant reduced from 30% to 12% in the SAGD-COG scenario compared to the reference case. After 2035, less endogenous natural gas combined cycle capacity is added to meet reserve margins due to the capacity additions of cogeneration. The efficiency difference between cogeneration and combined cycle is less than the difference between cogeneration and converted coal to gas and simple cycle technologies, resulting in the annual GHG mitigation trend observed.

The cumulative GHG abatement potential of the cogeneration scenarios considering all three subsectors is shown for each year in the evaluation period in Fig. 5. Based on the modelling, cumulative GHG mitigation potential due to cogeneration in the three subsectors was 26 Mt in 2030 and 76 Mt in 2050. The SAGD subsector contributed 72 Mt of the 2050 abatement potential (95% 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 Alberta. If these GHG emission reductions are allocated to the oil sands industry, they would represent a decrease of 2% of sector-wide cumulative oil sands emissions from the reference case GHG emissions through the 2019–2050 evaluation period.

These results were benchmarked against two other studies that investigated the potential of cogeneration to reduce emissions in Alberta. A previous study investigating emission savings possible with oil sands cogeneration from 2008 to 2020 found 11–17% of Alberta electricity sector GHG emissions could be mitigated over that time period [20], whereas the present study found an average of 7% of annual 2019–2050 (5% cumulative emissions) electricity sector emissions could be mitigated. This difference is expected given the long-term time scale of the present study and the renewable energy transition occurring by 2030 in Alberta, resulting in less mitigation potential due to cogeneration. A more recent study estimated that province-wide annual emissions could be reduced by 13–26% by 2030 using cogeneration in SAGD facilities [21], whereas the present study found that the 2030 reductions would be closer to 5–10% in that year. The past study however does not consider a dynamic model that considers the Alberta electricity system and instead applies exogenous assumptions to capacity growth and displacement. While the approach offers value in terms of evaluating the extreme ends of technology adoptions, the present study contrasts this with the results considering market penetration modelling and system-wide analysis. 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.

3.3. Marginal greenhouse gas emission abatement cost curves

The combined marginal abatement cost of the long-term GHG

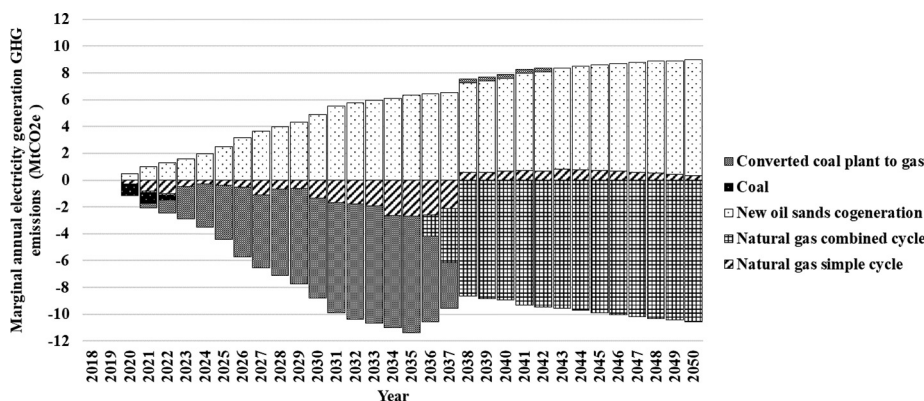


Fig. 4. SAGD-COG-CP30 scenario electricity generation marginal GHG emissions compared to the reference scenario.

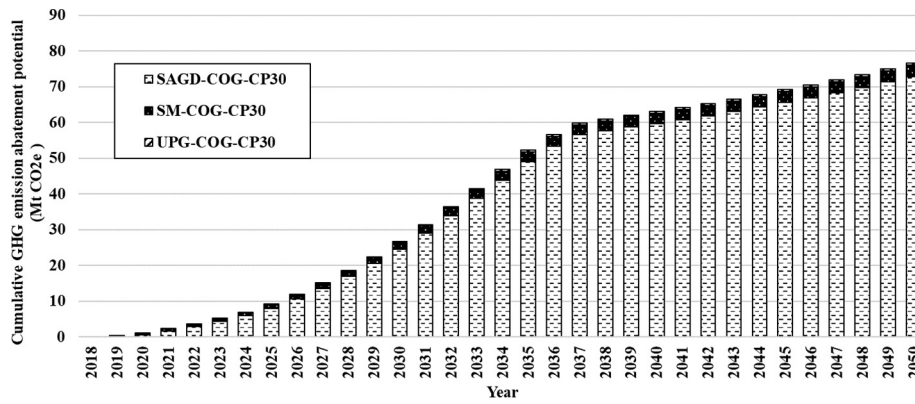


Fig. 5. Cumulative GHG emission abatement representing maximum potential with CP30 scenarios compared to the reference scenario.

emission abatement potential (~2%) is calculated to be \$15/tCO_{2e} through the implementation of cogeneration across subsectors (SAGD-COG, UPG-COG, and SM-COG scenarios). Fig. 6 shows the scenario cost curve results for cogeneration and electric equipment scenarios for the 2019–2050 evaluation period at CP30 conditions. Changing the carbon pricing from CP0 to CP50 increased the abatement potential in the SAGD, mining, and upgrading subsectors by 2, 3, and 0%, respectively. Full results are in the [Supplementary Information](#).

Both the upgrading and surface mining subsectors provide GHG abatement with expected cost savings over the evaluation period at CP30 conditions. Carbon pricing resulted in a \$26 and \$3/tCO_{2e} marginal cost decrease from CP0 to CP50 for the mining and upgrading scenarios, respectively. Since the mining and upgrading sectors have relatively smaller cogeneration additions per barrel of production, and low projected growth, there is limited emission reductions. The results show strong long-term cost-saving opportunities through cogeneration in the mining and upgrading subsectors at the modelled costs and electricity mix.

Marginal cost results for the SAGD subsector are upwards of \$26/tCO_{2e}. The abatement potential is largely due to the greater forecasted growth in the SAGD subsector combined with the larger cogeneration plants required to meet SAGD steam demands, producing greater technology penetration. Because of the higher abatement potential, the SAGD subsector scenarios still offer the best opportunities to reduce GHG emissions, despite the higher marginal abatement costs

GHG abatement potential and marginal cost results from the SAGD subsector electrification scenarios, shown in Fig. 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 considering the modeled conditions and chosen cost-benefit analysis. 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 54 Mt of abatement potential at \$43/t marginal cost in CP30 conditions. Compared to the basic SAGD cogeneration scenario at the same carbon price, this is a 19 Mt reduction in abatement potential and a \$17/t increase in marginal cost.

3.4. Sensitivity analysis

The results of the sensitivity analysis are presented for CP30 scenarios for the SAGD-COG, SM-COG, and UPG-COG scenarios. Full sensitivity analysis results are available in the [Supplementary Information](#).

Fig. 7 shows the sensitivity results to changes in the cost variance parameter over the suggested range of values for the energy industry. No significant differences in marginal abatement cost results were observed across the range of cost variance values. A notable change in GHG mitigation did occur for the SAGD case due to market share changes. Changes were prominent only in the SAGD scenario because SAGD production experienced high growth relative to the other cases, allowing for more penetration of cogeneration, thus more sensitive to the cost variance parameter.

Fig. 8 shows the abatement potential results for the range of capital costs used to evaluate the LCC of project costs in each scenario. For this analysis, the reference scenario capital costs remained fixed, and the capital cost of the cogeneration alternative was varied. The SAGD

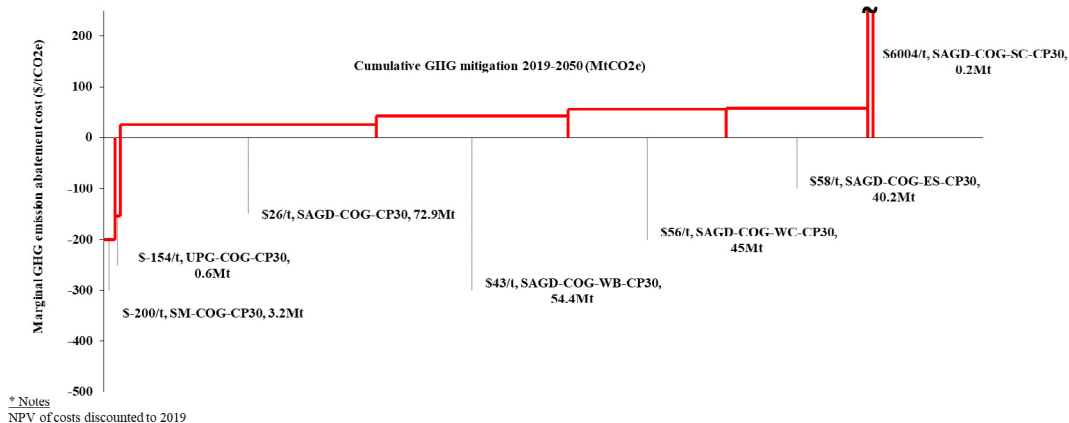


Fig. 6. Marginal GHG abatement cost curve for CP30 scenarios.

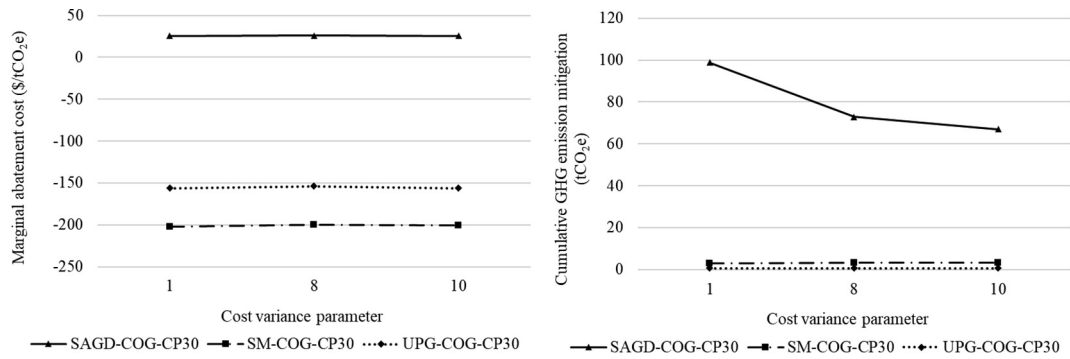


Fig. 7. Sensitivity of results to changes in the cost variance parameter.

scenario reached negative abatement costs at about 13% of capital cost reduction. The marginal abatement costs for the surface mining cogeneration scenario became positive at about a 10% increase in capital costs. The upgrading scenario was highly sensitivity, due to the already limited GHG mitigation from low growth in the sector. The GHG mitigation of the SAGD scenario was significantly impacted by changes. A 30% increase in capital cost reduced the SAGD-COG abatement potential by 64% from the base result as the technology penetrates the market at a much slower rate. It is expected that SAGD would be most impacted by capital cost changes because the SAGD process has the highest steam requirement and therefore the highest marginal capital costs associated with adding cogeneration plants. The higher capital costs result in a larger marginal cost change when the capital cost value is increased. Surface mining and upgrading were less significantly impacted when compared to the SAGD scenarios. Despite the lower impact of capital cost 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 financial capital of adding cogeneration to facilities plays a major role in the technology’s market penetration viability and subsequent abatement potential from changing technology penetration rate.

The sensitivity of GHG abatement potential to changes in forecasted natural gas prices for each technology is shown in Fig. 9. Lower and higher natural gas price forecasts did not have large impacts on the marginal abatement costs. While the SAGD-COG marginal cost reduced by 22% with lower natural gas prices, it was not enough to bring the costs below 0. The SAGD-COG GHG abatement potential increased by 5 Mt when forecasted natural gas prices decreased by 20% and decreased by 4 Mt when forecasted natural gas prices increased by 20%. As with the capital cost sensitivity, the larger relative size of cogeneration facilities required to meet the high heat requirement of SAGD increases the sensitivity. 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.

Results were also tested in relation to changes to the forecasted market growth, and the results are shown in Fig. 10. Marginal costs were not greatly affected by changes in production since the marginal costs and GHG mitigation change in proportion to changes in production. Interestingly, a slight change was found in the results for the mining and upgrading scenario results with SAGD production growth. This was due to more cogeneration penetration into the oil sands associated with more SAGD growth, which lowered the overall Alberta electricity emission factor, leading to more GHG mitigation in all sectors. The SAGD-COG GHG mitigation potential was most sensitive to changes in market growth; abatement potential was as low as 57 Mt and as high as 89 Mt from a base value of 72 Mt.

The base efficiency value of the cogeneration plants (61%) was varied by ± 10% and the abatement potential results are shown in Fig. 11. All scenarios showed variation in the GHG abatement potential across this range. The SAGD scenario varied from 39 Mt to 97 Mt at the low to high efficiency, respectively, from a base value of 72 Mt. The surface mining and upgrading scenarios decreased to 38% and 41%, of the base value at the lowest efficiency and increased to 27% and 30% of the base value at the highest efficiency, respectively. 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, coal to natural gas converted plants, simple cycle natural gas plants, and stand-alone steam generation. When the cogeneration plant efficiency is decreased to 51% there is less advantage over other plants, reducing GHG abatement potential considerably. With the lower efficiency, after 2035 the scenarios increased GHG emissions. These results show that the amount of efficiency gained from the replacement of stand-alone steam generation should be carefully evaluated, along with the long-term emission factor of the grid electricity supply option.

The sensitivity of the results to electricity costs and sale prices were also evaluated in Fig. 12. Marginal abatement costs for cogeneration scenario results in the mining and upgrading sectors remain negative whereas increases in the electrical energy and transmission cost greatly

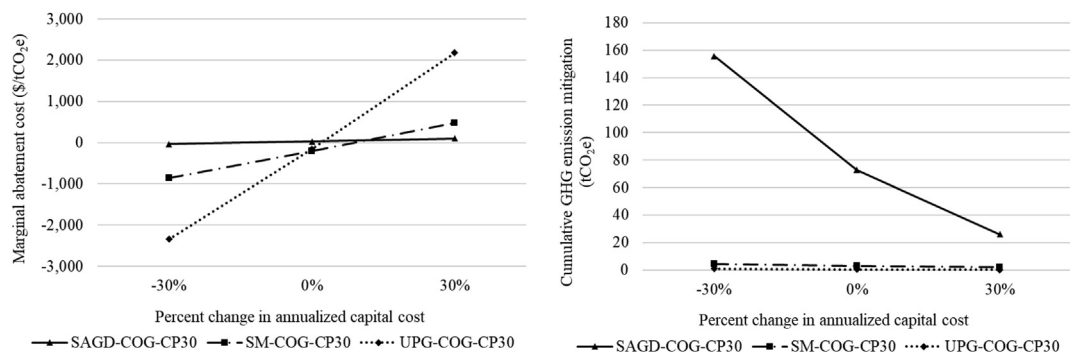


Fig. 8. Sensitivity of results to changes in capital costs associated with cogeneration.

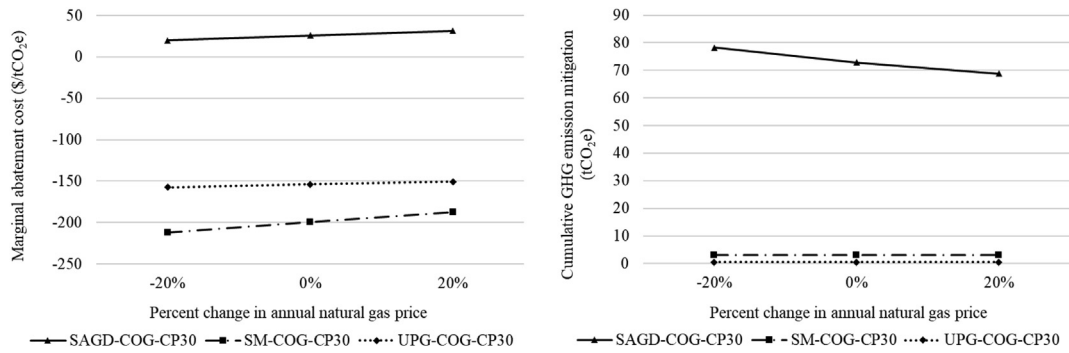


Fig. 9. Sensitivity of results to changes in the forecasted natural gas price.

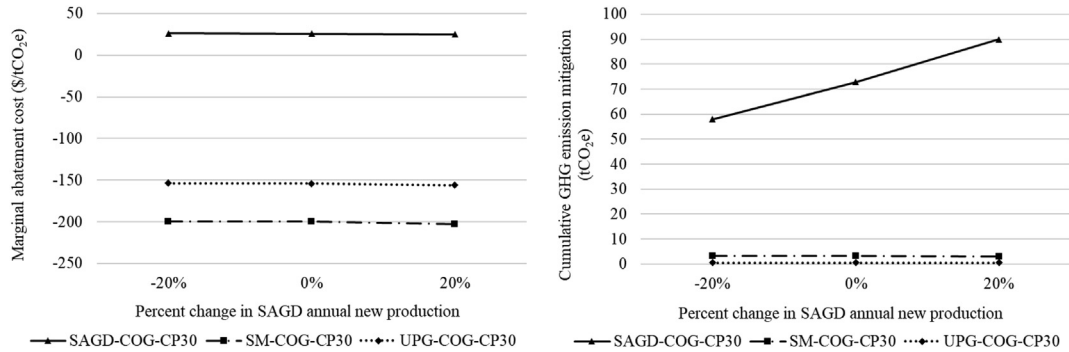


Fig. 10. Sensitivity of results to changes in forecasted SAGD market growth.

reduce the SAGD-COG marginal costs due to higher revenue from the sale of exported electricity to the grid, lowering the marginal costs of cogeneration in SAGD plants. If forecasted Alberta pool prices rise 20% above the modelled prices, the long-term marginal abatement cost for cogeneration in the SAGD subsector would become negative.

The Alberta electricity emission factor which is used to allocate emissions to electricity consumption from grid-purchased electricity has minimal impact on results at the ranges investigated as observed in Fig. 13. As cogeneration increases over time, the Alberta grid is becoming less carbon-intensive primarily due to the high penetration of renewables (30% of generation by 2030) and phase out of coal power by 2030.

Fig. 14 shows the change in results if the current Alberta industry carbon pricing (CP30) changed to a fully applied carbon price of \$50/tCO₂e. In other words, if all emissions were charged the carbon price, instead of the regulated portion as stipulated by the current policy. This analysis resulted in an additional 15% of cumulative GHG mitigation and an 18% reduction in marginal abatement cost for the SAGD-COG scenario relative to the CP30 case.

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 currently available data, but those parameters are determined using inputs that can vary unexpectedly and site to site. 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 logistic 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,

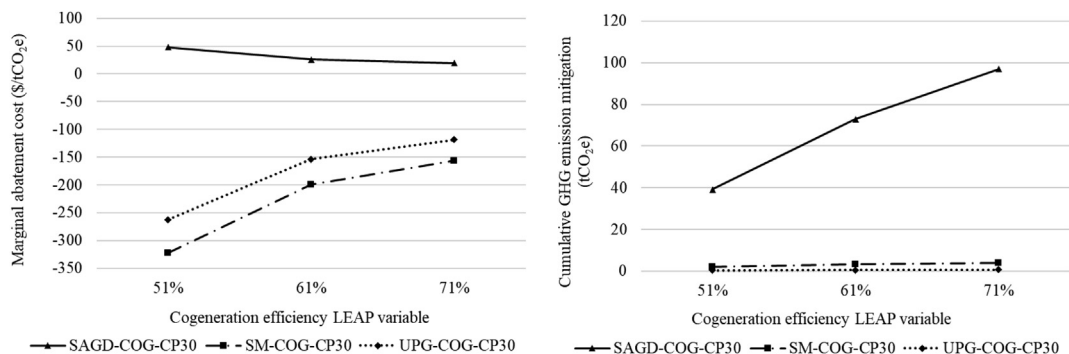


Fig. 11. Sensitivity of results to changes in cogeneration plant efficiency LEAP variable.

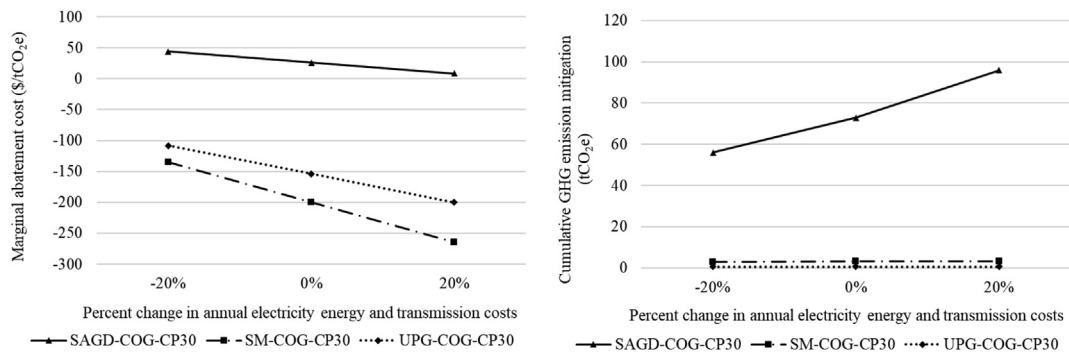


Fig. 12. Sensitivity of results to changes in electricity costs.

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.

The SAGD electric equipment scenarios consider the addition of the equipment to plants with cogeneration. The costs and energy data were sourced from an analysis considering a base case SAGD plant without cogeneration. While the costs and energy changes were scaled to a SAGD with a cogeneration plant, process modelling would make for a more robust assessment of facility-level cost and energy-use changes.

Lastly, the scenarios considered only one set of plant configuration and cogeneration plant sizes. Further analysis considering different plant sizes and configurations would be valuable and could have different results in terms of market penetration, cost-effectiveness, and GHG mitigation potential.

4. Conclusion

Cogeneration has played a key role in increasing operating efficiency while reducing greenhouse gas emissions from the oil sands industry and producing electricity with a lower greenhouse gas intensity than grid electricity. In this study, three different oil sands subsectors were evaluated for the years 2019 to 2050 for the potential to increase cogeneration penetration as a way of reducing greenhouse gas emissions from the industry. Four additional scenarios in the steam-assisted gravity drainage subsector were evaluated over the same period to determine the potential for electricity-based technologies to further reduce greenhouse gas emissions from the steam-assisted gravity drainage 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 cogeneration offers the greatest potential to gain market share, up to 16% of total production, primarily because of the significant growth expected in that subsector during the evaluation period. Correspondingly, steam-assisted gravity drainage scenarios offer up to 72 MtCO₂e of greenhouse gas abatement potential in the evaluation period, while surface mining and upgrading offer up to 3 Mt and 0.6 Mt. Cumulatively, these results represent about a 2% reduction in emissions for the oil sands industry between 2019 and 2050, or 1.3% of 2050 emissions, when compared to the reference scenario. These combined GHG emission reductions were found to come at a marginal cost of \$15 per tonne. When viewing the emission reduction from the perspective of electricity generation in Alberta, 5% of cumulative emissions can be reduced due to oil sands cogeneration, or 5% of 2050 emissions compared to the reference scenario. Cogeneration scenarios in the upgrading, and surface mining subsectors resulted in negative abatement cost, indicating cost savings in the long term. Cogeneration in steam-assisted gravity drainage scenarios resulting in positive abatement costs, however with a 20%+ increase in modelled electricity costs, the abatement cost approaches a negative value. 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 under the current regulation. The results from scenarios incorporating additional electrical equipment into the steam-assisted gravity drainage did not increase greenhouse gas mitigation or decrease marginal abatement costs.

The results of this study demonstrate the efficacy of using cogeneration for unconventional oil extraction and may be useful to oil sands and other unconventional oil stakeholders and government policy-makers for long-term planning. The framework developed and methods employed can be applied to evaluate international developments of unconventional oil with appropriate adjustment of variables such as energy intensity of extraction processes, production volumes, energy prices, and electricity grid mix emission factors. The results demonstrated the importance of considering such long-term system-wide

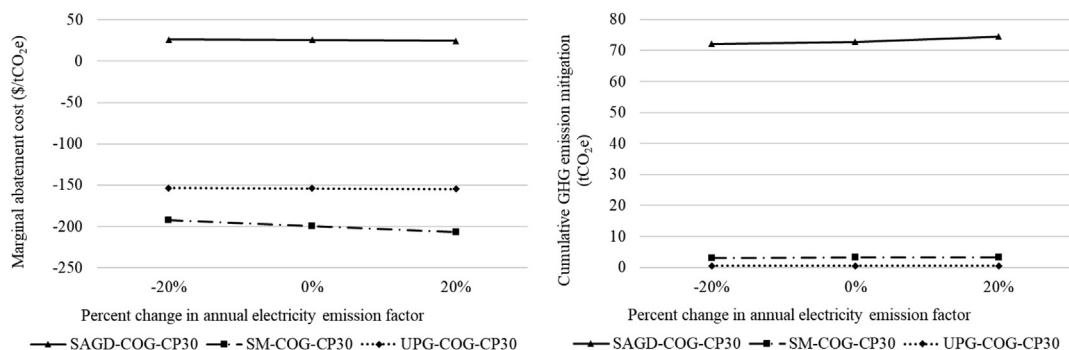


Fig. 13. Sensitivity of results to changes in electricity emission factor used in the market share model.

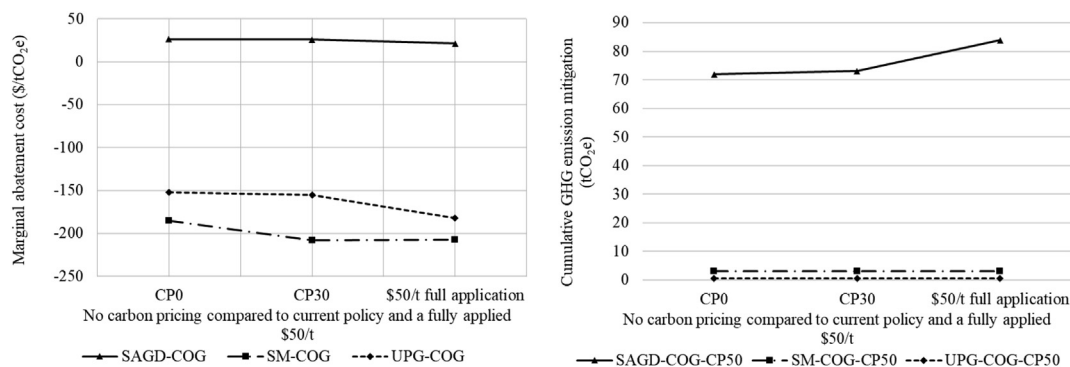


Fig. 14. Sensitivity of results to changes in applied carbon price.

impacts. For instance, the greenhouse gas mitigation potential associated with cogeneration was greatly attenuated by the long-term electricity grid emission factor transition from a carbon-intensive to low-carbon value.

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

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.enconman.2020.112755>.

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